COMMERCE DEPARTMENT

February 26, 2026 **PUBLIC DOCUMENT**

Sasha Bergman
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, Minnesota 55101-2147

RE: **PUBLIC** Comments of the Minnesota Department of Commerce
Docket No. E002/M-25-142

Dear Ms. Bergman,

Attached are the **PUBLIC** comments of the Minnesota Department of Commerce (Department) in the following matter:

In the Matter of Xcel Energy's 2025 Integrated Distribution Plan.

Xcel Energy's (Xcel or the Company) Integrated Distribution Plan (IDP) was filed on October 31, 2025. Xcel's Transportation Electrification Plan was filed concurrently.

The Department recommends the Commission accept Xcel's IDP with additional requirements and is available to answer any questions the Minnesota Public Utilities Commission may have.

Sincerely,

/s/ Dr. SYDNIE LIEB
Assistant Commissioner of Regulatory Analysis

AZ/RW/BP/KB/DD/ar
Attachment

Contents

List of Tables

List of Figures

Acronyms and Abbreviations

ADMS	Advanced Distribution Management System
AGIS	Advanced Grid Intelligence and Security
AMI	Advanced Metering Infrastructure
AOM	Advanced Outage Management
ARR Split	Avoided Revenue Requirement Split
BESS	Battery Energy Storage System
BTM	Behind the Meter
CAIDI	Customer Average Interruption Duration Index
CBA/BCA	Cost-Benefit Analysis/Benefit Cost Analysis
CELI	Customers Experiencing Lengthy Interruptions
CEMI	Customers Experiencing Multiple Interruptions
CIAC	Contributions in Aid of Construction
CIP	Conservation Improvement Program
CSG	Community Solar Garden
DCP	Distributed Capacity Procurement
DER	Distributed Energy Resource
DERMS	Distributed Energy Resources Management System
DI	Distributed Intelligence
DG	Distributed Generation
DGWG	Distributed Generation Working Group
DOE	US Department of Energy
DR	Demand Response
DRMS	Demand Response Management Systems
DSM	Demand Side Management
ECO	Energy Conservation & Optimization
EV	Electric Vehicle
FAN	Field Area Network
FERC	Federal Energy Regulatory Commission
FI	Flexible Interconnection
FLISR	Fault Location Isolation and Service Restoration
FLM	Feeder Load Monitoring
FTM	Front of the Meter
GIS	Geographic Information System
Grid Mod	Grid Modernization
HAN	Home Area Network
HCA	Hosting Capacity Analysis
IDP	Integrated Distribution Plan
IR	Information Request
IRA	Inflation Reduction Act
IRP	Integrated Resource Plan
IVVO	Integrated Volt-Var Optimization
kV	Kilo Volt
kW	Kilowatt
LBNL	Lawrence Berkley National Laboratory
kWh	Kilowatt-Hour
MAIFI	Momentary Average Interruption Frequency Index

MED	Major Event Day
MISO	Midcontinent Independent System Operator
MN DIP	Minnesota Distributed Interconnection Procedures
MP	Minnesota Power
MW	Megawatt
NERC	North American Electric Reliability Corporation
NPV	Net Present Value
NSPM	Northern States Power Company
NWA	Non-Wire Alternative
O&M	Operations and Maintenance
OMS	Outage Management System
PNL	Planned Net Load
PUC	Public Utilities Commission
PUP	Proactive Upgrade Proposal
PV	Photovoltaic
RFI	Request for Information
RFP	Request for Proposal
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SQRS	Service Quality, Safety, and Reliability
TCR	Transmission Cost Recovery
TEP	Transportation Electrification Plan
TOD	Time of Day
TOU	Time of Use
WACC	Weighted Average Cost of Capital
Xcel	Xcel Energy

Before the Minnesota Public Utilities Commission

PUBLIC Comments of the Minnesota Department of Commerce

Docket No. E002/M-25-142

I. INTRODUCTION

Every two years, the Northern States Power Company, doing business as Xcel Energy (Xcel or the Company) is required to submit an Integrated Distribution Plan (IDP), which began with the Minnesota Public Utilities Commission's (Commission) August 30, 2018 Order Approving Integrated Distribution Planning Filing Requirements for Xcel Energy.[1] The primary mechanism by which IDPs operate is compliance with the Commission's established filing requirements. The Commission accepts the IDP if it finds that Xcel complies with its established filing requirements. Since the Commission's August 30, 2018 Order, the Commission has modified its filing process and/or requirements in every IDP.[2,3,4,5] Throughout this process, the Commission has also ordered one-time compliance requirements to add additional analysis that enriches the depth of the IDP process. This history of IDPs reveals that the IDP process has consistently adapted to meet varying informational needs about distribution system planning.

With acknowledgement of the ever-evolving nature of the IDP process, the Minnesota Department of Commerce (Department) advocates for the next set of IDP modifications to improve the impact of its IDPs. It is important to establish that IDPs are not meant to serve as a prudency review, or to otherwise preclude utilities from making timely changes to their distribution systems that are not included in IDPs.[6] The only existing mechanism within the IDP process to approve specific investments is certification for utilities on a multi-year rate plan, such as Xcel.[7] Aside from items requested for certification, the IDPs only provide information that can be used for future decision making processes, such as cost recovery proceedings. Despite the lack of a direct connection to cost recovery, the Commission established processes to affect utility decision making within the IDPs. The two most

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[1] *In the Matter of Distribution System Planning for Xcel Energy*, *Order Approving Integrated Distribution Planning Filing Requirements for Xcel Energy*, August 30, 2018, Docket No. E-002/CI-18-251, (eDockets) 20188-146119-01, (hereinafter "August 30, 2018 Order").

[2] *In the Matter of Xcel Energy's 2018 Integrated Distribution Plan*, *Order Accepting Report, and Amending Requirements*, July 16, 2019, Docket No. E002-CI-18-251, (eDockets) 20197-154416-01 (hereinafter "July 16, 2019 Order").

[3] *In the Matter of Xcel Energy's Integrated Distribution Plan and Advanced Grid Intelligence and Security Certification Request*, *Order Accepting Integrated Distribution Plan and Modifying Filing Requirements*, November 2, 2020, Docket No. E002/M-19-666, (eDockets) 202011-167944-03.

[4] *Order Accepting 2021 Integrated Distribution System Plan and Certifying the Resilient Minneapolis Project,* July 26, 2022, Docket No. E002/M-21-694, (eDockets) 20227-187764-01 (hereinafter "July 26, 2022 Order").

[5] *In the Matter of Xcel Energy's 2023 Integrated Distribution Plan*, *Order Accepting 2023 Integrated Distribution Plan and Modifying Reporting Requirements*, September 16, 2024, Docket No. E002/M-23-452, (eDockets) 20249-210223-01 (hereinafter "2023 IDP Order").

[6] August 30, 2018 Order – Attachment A at 1.

[7] Minn. Stat. § 216B.2425, subd. 3 (2023).

significant examples of these processes regard non-wires alternatives analysis (NWA) and Planned Net Loading (PNL). For example, Filing Requirement E.1 states:

> Xcel shall provide a detailed discussion of all distribution system projects in the filing year and the subsequent 5 years that are anticipated to have a total cost of greater than two million dollars. For any forthcoming project or project in the filing year, which cost two million dollars or more, provide an analysis on how non-wires alternatives compare in terms of viability, price, and long-term value.[8]

In compliance with the Commission's filing requirement, Xcel provides a cost-benefit analysis of its capacity projects, which can impact project selection in the future. In addition, in Xcel's 2023 IDP, the Commission ordered Xcel to modify its planning standards with regard to PNL:

> 17. Xcel shall work with stakeholders to refine its planned net load methodology. Xcel shall also evaluate alternative approaches to applying the dependability factor, including applying it to hourly photovoltaic generation and to photovoltaic nameplate capacity. Xcel shall engage parties that commented on planned net load in this proceeding as it evaluates seasonal dependability factors and alternative planned net load approaches. Xcel shall include a report describing the results of this evaluation and changes to its proposed planned net load methodology in its next IDP.
>
> 18. Xcel shall implement the 15 percent DFPV in the next planning cycle for N-0 risk analysis in the next IDP.[9]

While neither of these requirements establish prudency, or determine the allowance of specific projects, both examples highlight the Commission's authority to modify Xcel's existing decision processes in ways that could affect Xcel's budget requests in cost recovery proceedings. To date, both IDP requirements have had only a small impact on Xcel's budget, but there are similar risk-based planning standards that could have a more significant impact on Xcel's budget.

In these comments, the Department advocates for an expansion of the review of Xcel's planning standards with a key objective to reduce Xcel's planned distribution spending. By every measure, Xcel's distribution spending will at least double within its planning cycle, and this budget raises significant energy affordability concerns. Both NWA and PNL are fundamentally risk-management processes that seek to manage the risk of distributed energy resources being available when the distribution grid requires them. Xcel has many more risk-based standards that must be reviewed to ensure that these standards prioritize safety, reliability, and cost effectiveness. These comments will demonstrate that

[8] *In the Matter of Xcel Energy's 2025 Integrated Distribution Plan*, *Notice of Comment Period*, November 13, 2025, Docket No. E-002/M-25-142, (eDockets) 202511-224924-01, at 9-10 (hereinafter "Notice").
[9] September 16, 2024 Order – at 26.

Xcel's planning standards prioritize the abatement of worst-case scenarios that are often rare, with limited data to support their efficacy, and little, if any consideration of cost effectiveness. Xcel's planning standards in capacity and wildfire alone induce over two billion dollars of spending by 2030 to manage these risks.

While no one wants more outages, a perfectly reliable system is useless if no one can afford to pay the bills. There is a midpoint between undergrounding a powerline to serve a single vacation home located 5 miles down a road and upgrading an old, chronically unreliable substation transformer that serves 10,000 customers. That midpoint optimally balances the societal cost of reliability and utility spending. Based on the Department's analysis, Xcel's planning standards appear closer aligned towards serving the costly reliability needs of the vacation home, which opens significant opportunities for reduced distribution spending. The Department seeks to collaborate with Xcel engineers and other intervenors to ensure that Xcel's decision processes and criteria consider cost effectiveness. Where these standards do not consider cost effectiveness, the Department seeks to evaluate alternative planning standards that factor in cost effectiveness, where it is appropriate to do so.

The Department's review of planning standards aligns with the Commission's planning objectives 4 and 5 to optimize the distribution system and to comprehensively analyze ratepayer cost and value, which state:

> 4. Ensure optimized utilization of electricity grid assets and resources to minimize total system costs; and
>
> 5. 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.[10]

Xcel's planning standards are the central focus of these comments. The Department first addresses the Commission's planning objectives, and the need for IDP process changes. The comments then discuss strategies to enhance distribution system optimization. With this background, the comments outline how reliability is valued, and then discuss specifically how Xcel's forecasting, capacity, and wildfire planning standards affect Xcel's budget. In a similar theme, the comments address Xcel's Targeted Underground Proposal. Finally, the comments address other IDP notice topics, which include programmatic cost benefit analysis, grid modernization, PNL, NWA, Xcel's mobile battery certification request, proactive capacity investments, equity analysis, and geospatial analysis.

[10] Notice – at 3.

II. PROCEDURAL BACKGROUND

December 8, 2022	The Commission issued its Order in Docket Nos. E002/M-21-694, E999/CI-17-879.[11] The Order approved combining the filing requirements of electric utility IDPs and TEPs.
May 2023	The Minnesota Legislature established requirements for utility TEPs in 2023 Minn. Laws. ch. 60, art. 12, sec. 12, codified at Minn. Stat. § 216B.1615 – Electric Vehicle Deployment Program. Minn. Stat. § 216B.1615 requires electric utilities to file TEPs, established certain content requirements, granted the Commission authority to approve, modify or reject TEPs, and established evaluation criteria.[12]
August 23, 2023	The Commission issued its *Order Accepting Withdrawal of Clean Transportation Portfolio Subject to Conditions*. The Order placed a number of conditions upon Xcel Energy, including that it file a TEP by November 1, 2023 consistent with Minn. Stat. § 216B.1615 and that various components and information be included in its filing.[13]
September 14, 2024	The Commission issued its Order Accepting Xcel's 2023 IDP and Modifying Reporting Requirements.[14]
October 31, 2025	Xcel files its 2025 TEP and IDP.[15]
November 13, 2025	The Commission issues its Notice of Comment Period in the present docket.[16]
January 28, 2026	The Department files initial comments in response to Xcel's first Proactive Upgrade Proposal.[17]

[11] *In the Matter of a Commission Inquiry into Electric Vehicle Charging and Infrastructure; In the Matter of Xcel Energy's 2021 Integrated Distribution System Plan; In the Matter of Minnesota Power's 2021 Integrated Distribution System Plan; In the Matter of Distribution System Planning for Otter Tail Power Company, Order,* December 8, 2022, Docket Nos. E-99/CI-17-879, E-002/M-21-694, E-015/M-21-390, E-017/M-21-612 (eDockets) 202212-191192-01.
[12] Minn. Stat. § 216B.1615 (2023).
[13] *In the Matter of the Petition of Northern States Power Company for Approval of a Public Charging Network and Electric School Bus Pilot and Program Modifications*, *Order Accepting Withdrawal of Clean Transportation Portfolio Subject to Conditions*, August 23, 2023, Docket No. E002/M-22-432 (eDockets) 20238-198430-01.
[14] 2023 IDP Order.
[15] *In the Matter of Xcel Energy's 2025 Integrated Distribution Plan*, Xcel, Compliance Filing, October 31, 2025, Docket No. E002/M-25-142, (eDockets) 202510-224538-01, (hereinafter "2025 IDP").
[16] Notice.
[17] Department, Comments, January 28, 2026, Docket No. E002-M-25-142, (eDockets) 20261-227533-02 (hereinafter "Department Initial Comments on Xcel's Proactive Upgrade Proposal").

Topic(s) open for comment:

Xcel Energy 2025 Certification Request: Mobile Battery System

11. Should the Commission approve, modify, or deny certification of the mobile battery system?
12. Should the Commission approve, modify, or deny Xcel's request to streamline the certification process by requiring the following information to evaluate whether the proposed project serves the public interest:
    a. A description of why the project is necessary for grid modernization;
    b. A description of the project's objectives and potential benefits to customers;
    c. A cost range for the project; and
    d. The expected timing for project implementation.
13. Are there any other issues or concerns related to this matter?

Xcel Energy 2025 Integrated Distribution System Plan

14. Should the Commission accept or reject Xcel's IDP?
15. Did Xcel adequately address the Commission's IDP filing requirements and prior Orders, as outlined in Attachment A to this notice?
16. Feedback, comments, and recommendations on the following areas of Xcel's IDP:
    a. Forecasted distribution budget
    b. Forecasting results and methodology
    c. Proactive capacity investments
    d. Updated Planned Net Load (PNL) methodology and risk analysis results
    e. Targeted undergrounding proposal
    f. Proposed cost-benefit analysis for discretionary distribution investments
    g. Non-Wires Alternative Analysis
    h. Distributed Energy Resource Management System (DERMS)
17. Other areas of Xcel's IDP not listed above, along with any other issues or concerns related to this matter.

III. DEPARTMENT ANALYSIS

These initial comments of the Department address Xcel's IDP and the Commission's Notice Topics 11 through 17. Recommendations are offered in the corresponding sections and are summarized at the conclusion of this filing.

For organization and clarity, these comments do not perfectly follow the sequence of topics in the Notice.

A. IDP COMPLIANCE WITH FILING REQUIREMENTS AND RECOMMENDATIONS CONCERNING ACCEPTANCE

The Department responds to the following notice topics:

Notice Topic 14: Should the Commission Accept or Reject Xcel Energy's IDP?

Notice Topic 15: Did Xcel Adequately Address the Commission's IDP Filing Requirements and Prior Orders, as Outlined in Attachment A to This Notice?

The Department recommends the Commission accept Xcel's 2025 IDP with additional order points. As part of the Department's review of Xcel's October 31, 2025 filing, the Department verifies that Xcel's filing includes the basic documentation required by the applicable Commission orders, rules, and statutes. While the Department's review process raises additional questions and concerns about the current filing, the attached compliance chart in Attachment A documents Xcel's compliance with the basic filing requirements established by the Commission in this docket.

B. PURPOSE OF THE IDPS

The Commission set forth five planning objectives for IDPs, with additional filing requirements to promote transparency in distribution system planning. The Commission's planning objectives for IDPs are to:

> 1. Maintain and enhance the safety, security, reliability, and resilience of the electricity grid, at fair and reasonable costs, consistent with the state's energy policies;
>
> 2. Enable greater customer engagement, empowerment, and options for energy services;
>
> 3. Move toward the creation of efficient, cost-effective, accessible grid platforms for new products, new services, and opportunities for adoption of new distributed technologies;
>
> 4. Ensure optimized utilization of electricity grid assets and resources to minimize total system costs; and
>
> 5. 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.[18]

The Department supports the five Commission planning objectives, but it does not fully support how these objectives have been operationalized through the existing IDP process. In this section, the Department presents an argument for why the IDP process should be updated to better align IDPs with other proceedings. The IDP filing requirements primary aim to provide information about the distribution system, but mostly do not seek to influence utility decision making. In the early years of IDPs, distribution budgets were relatively stable, with large spending increases associated with grid modernization efforts, such as smart meters. IDP Filing Requirement D.2.K, regarding the cost-benefit

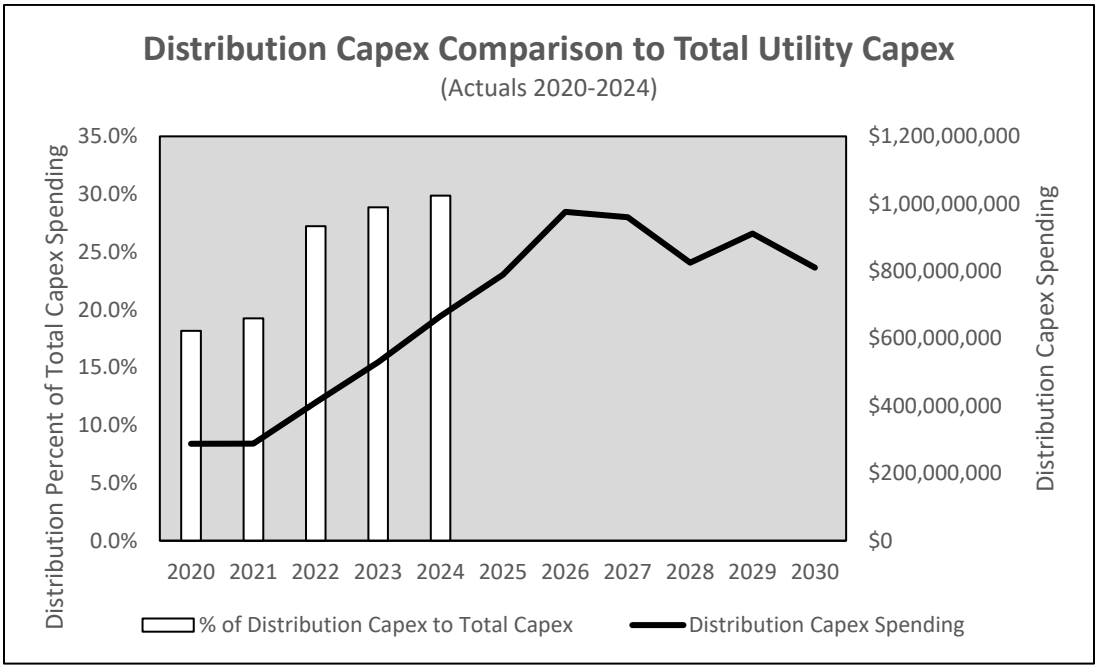
[18] Notice – at 3; *2021 Integrated Distribution Plan*, Xcel, November 1, 2021, Docket No. E002/M-21-694, (eDockets) 202111-179347-02 at Attachment B, 3.

analysis of grid modernization projects, was well suited to prepare Xcel to analyze whether its grid modernization efforts were cost effective.[19] However, the conditions present at the inception of IDPs are no longer the main budgetary concerns regarding IDP. The sources of Xcel's budget growth are more fundamental and often fall into mandatory spending categories. With Xcel's distribution spending more than doubling since the recent past, the existing filing requirements will not slow or prevent this outcome. New approaches are necessary to address Xcel's budget that expand beyond the traditional filing requirements.

B.1. Growing Need for Budgetary Scrutiny

Xcel's distribution budget has been growing significantly in the past five years. In real-dollar terms, Xcel's 2026 distribution budget is nearly four times higher than its 2018 budget.[20] More recently, Xcel's 2026 distribution budget is nearly three times higher than its 2021 budget, and will maintain a spending level that is at least twice as high as 2020 and 2021 spending by 2030.[21] This increase in spending has not been proportional to Xcel's spending on transmission and generation. Instead, distribution spending, as a share of total Xcel capex spending, has increased from 18% – 19% in 2020 and 2021 to 30% in 2024, which is shown in Figure 1. With distribution spending forecasted to remain above 2024 spending levels through 2030, it can be expected that Xcel's distribution spending will continue to take a significant share of total utility capex spending.

Figure 1: Comparison of Nominal Distribution Capex Spending to Nominal Total Xcel Capex Spending



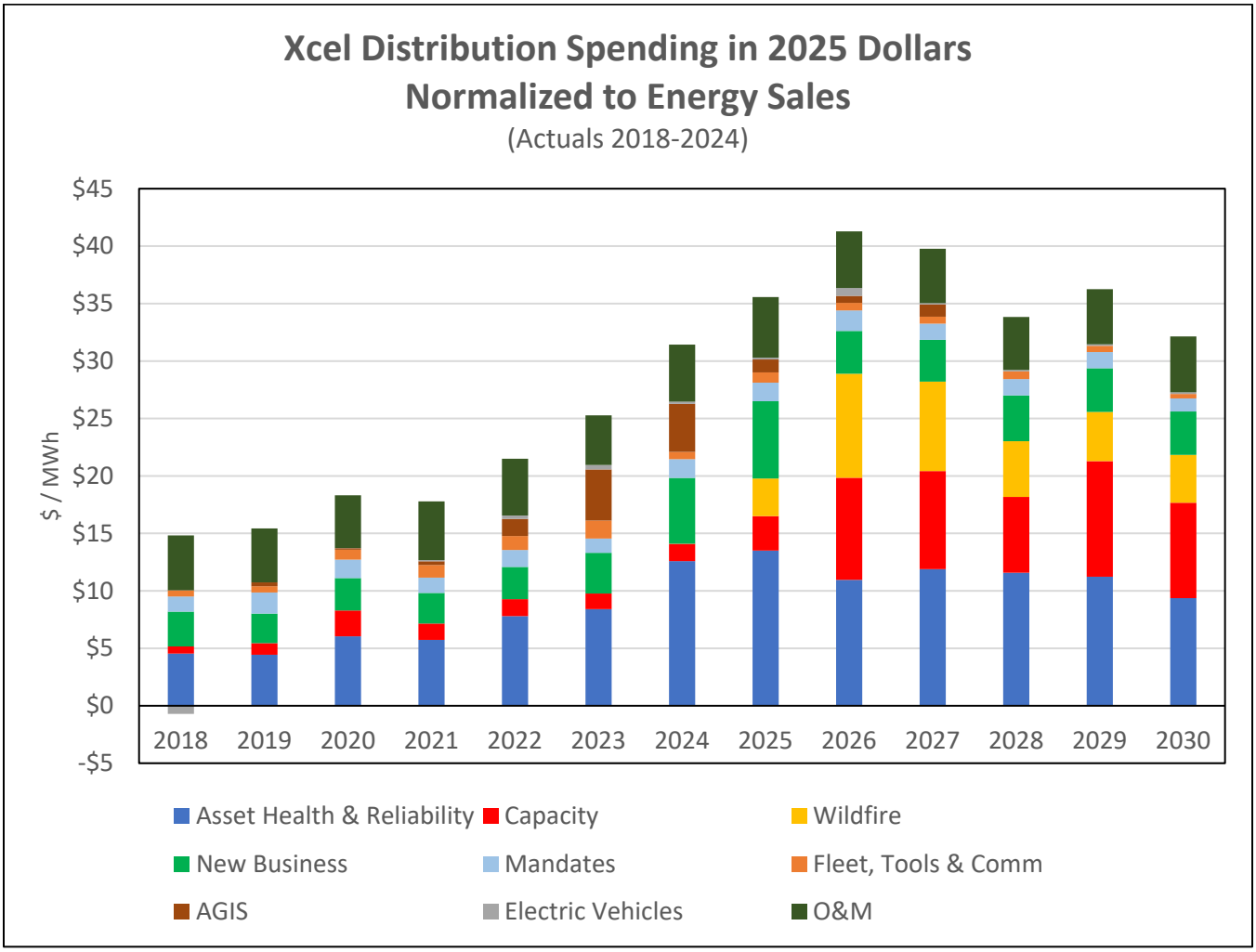
Source: Information Request (IR) 2 and 2025 IDP Attachment L

[19] Notice – at 9.
[20] See Figure 2.
[21] *Ibid*.

While the data on total capex spending provides a compelling argument for enhanced scrutiny of Xcel's distribution plan, increases in spending are most meaningful in the context of rates. To this end, the Department compares seven years of historical distribution (2018-2024) spending to Xcel's forecasted spending in this IDP (2025-2030) in Figure 2. The data is normalized to 2025 dollars and to distribution energy sales, which controls for inflation and actual changes to sales, and therefore impacts to customer bills. Figure 2 shows a clear trend that Xcel's distribution spending doubled between 2018-2019 and 2024, and Xcel's forecasted distribution budget is expected to remain well over double the 2018-2019 level in its forecasted distribution budget period. In addition, these increases in spending are not expected to be mitigated by new energy sales, at least in the near-term. These data support the data presented in Figure 1, which leads the Department to conclude that Xcel's distribution spending is significantly impacting rates. Finally, Xcel provides its own data to support a similar conclusion. Xcel reports that its distribution revenue requirements are expected to increase from $468,404,000 in 2021[22] to $1,048,136,000 in 2030.[23]

[22] 2021 IDP – Attachment G at 3.
[23] *Ibid*.

Figure 2: Comparison of Xcel Spending Over Time



Source: 2025 IDP – Attachment L, IR 32, IR 33, IR 37[24]

While distribution spending now makes up a large share of total utility capex spending and rates, there is essentially no secondary process to ensure that Xcel optimizes its distribution spending, as there is in an integrated resource plan (IRP) or in the Midcontinent Independent System Operator (MISO) transmission planning process. In an IRP, or in MISO's transmission planning process, optimization occurs to ensure that the least cost additions are made to the system. No such optimization exists for distribution investments. The current implementation of IDPs does not prove that the distribution system has been optimized. Given the significant share of utility spending on distribution investments, the Commission's Planning Objectives must be operationalized to create this process for distribution, particularly objectives 4 and 5. Actual spending, shown in Figure 2, demonstrates that the existing IDP and rate case processes have not succeeded in preventing Xcel's distribution budget from doubling in

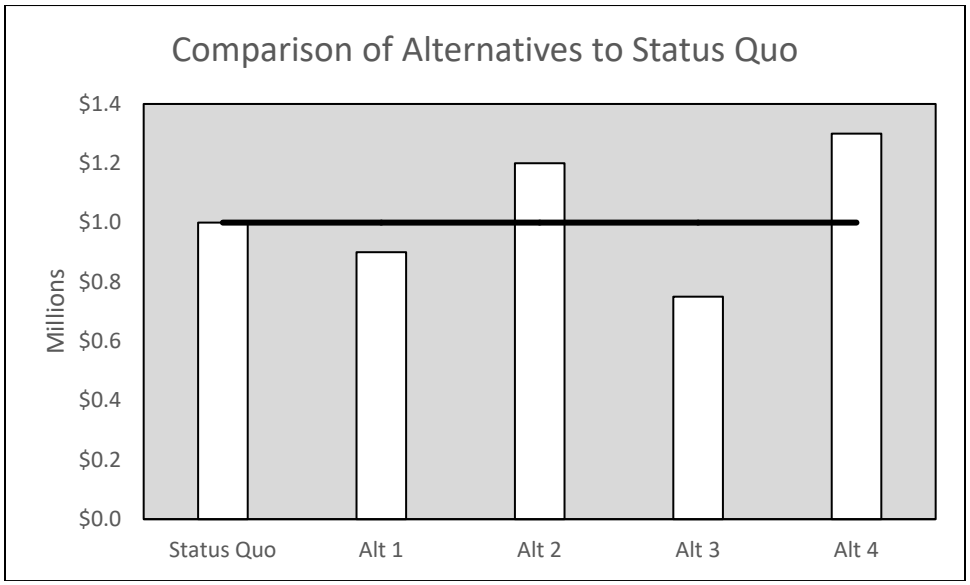
[24] The Department assumes 2% annual inflation after 2025, per Federal Reserve targets. Historical inflation based on June with data from https://www.bls.gov/data/inflation_calculator.htm.

just five years. With Xcel's distribution budget reaching close to $1 billion annually, there is a clear need for further scrutiny to determine whether all of this proposed spending is actually necessary.

B.2. Alignment With Rate Cases

The Department does not seek to turn IDPs into pre-rate cases. Fundamentally, rate cases are not optimization exercises, and are instead focused on whether proposed costs are reasonable and prudent for recovery, whereas IDPs are designed to evaluate planning strategies and identify cost effective approaches at the system level. The Department illustrates the fundamental difference between optimization and prudency in Figure 3, which shows the cost of hypothetical alternatives compared to a status quo. In a rate case, in order to demonstrate the prudency of an investment, Xcel may or may not need to compare its spending to spending under any other scenario (Status Quo in Figure 3). For spending that Xcel considers to be non-discretionary, such as capacity or age-related spending, Xcel may only need to prove that it procures the materials properly or that spending is reasonable for rate recovery purposes. For discretionary spending, such as advanced metering infrastructure (AMI), Xcel may only need to compare proposed spending under a new program to the status quo (Alt 1 in Figure 3). In Figure 3, Alternative 1 offers a 10 percent cost savings, and therefore offers a better value than the status quo, and should be approved for cost recovery. The rate case is not tasked with the consideration of other alternatives (Alternatives 2, 3, and 4 in Figure 3). If Xcel were required to consider Alternatives 2, 3, or 4, it would find that Alternative 3 offers a 25 percent cost savings—and therefore is the optimal strategy, which is preferrable to Alternative 1.

Figure 3: Demonstration of Optimization in IDPs



Furthermore, the Department argues the rate case is not the appropriate venue to plan for system optimization. If it were, then IRPs and MISO transmission planning would not be necessary. Consistent with the Commission's planning objectives, the Department views the IDPs as the appropriate venue to explore alternative strategies before a utility makes a cost recovery request. Alternative analysis, even

if it requires cost-benefit analysis, is not a prudency determination that will be used to deny cost recovery in a rate case. The analysis of alternatives, rather, strengthens a utility's case for cost recovery. Therefore, the Department seeks to modify IDPs to support record development in a rate case, not to supplant the rate case.

Lastly, the rate case is not the appropriate venue to analyze how Xcel plans its distribution system. While distribution planning standards are covered later in these comments, it is sufficient to state here that the analysis of Xcel's distribution decision making process is not suitable for a rate case.

B.3. Optimization Within IDPs VS IRPs or Transmission Planning

The Department recognizes that the optimization process within an IDP is fundamentally different from the optimization process in an IRP or in transmission planning. Most importantly, the Department is not aware of optimization software that can run quantitative optimizations on the distribution system at this time. LoadSEER is the closest option, but the tool is designed for geospatial allocation modeling, rather than optimization of resource deployment. In addition, the distribution system has many more components at much lower cost compared to generation and transmission, which makes the exercise of optimizing the distribution system much more challenging. Optimization is much easier with tens of larger equipment systems that cost hundreds of millions of dollars compared to thousands of pieces of equipment that cost tens of thousands of dollars.

Despite these challenges, the Department believes there is a plethora of unexplored opportunities to optimize the distribution system. The Department initially sought to understand Xcel's budget growth by mapping spending to outcomes in the Distribution Data Working Group, which did not yield tangible results.[25] By understanding how much value Xcel creates with its budget, the Department can track trends over time to determine if factors such as inflation or distribution planning assumptions drive Xcel's budget growth. Utilities, in general, expressed great consternation over providing outcome data in IDPs due to fears over being denied cost recovery in a rate case and the redundancy of potentially asking for information twice. In addition to these concerns, utilities simply do not know what they install on their systems, or what value their projects create. Simple questions regarding new capacity created in the capacity budget, how old distribution assets are, and how much system assets are utilized have proven challenging for utilities to answer. The Department does not fault Xcel or any utility for not being able to answer these questions given the current regulatory paradigm, because utilities have never been required to provide these data, and they may not have tracked this information historically. Based on a lack of data availability, the Department pivots its strategy to understand Xcel's budget growth in a more ontological direction, which results in new opportunities to optimize the distribution system.

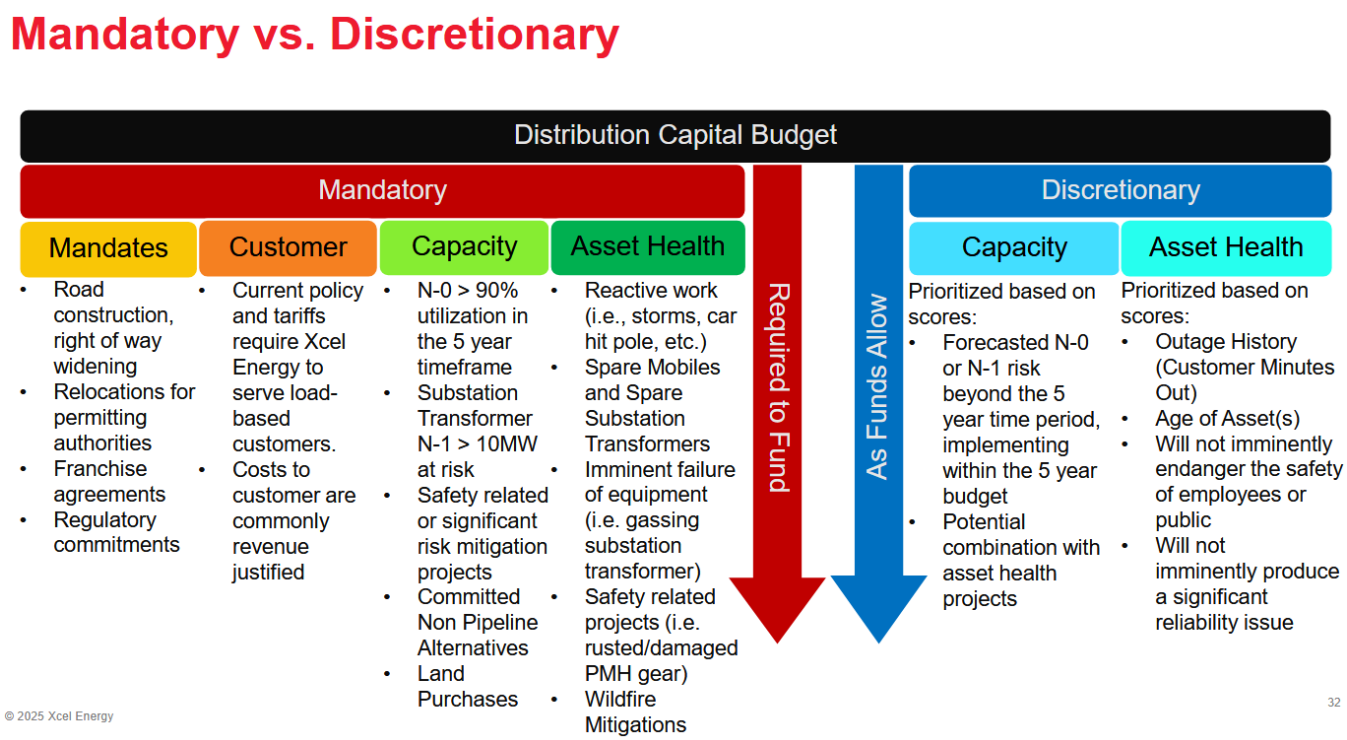
The main opportunities for distribution system optimization lie in the system planning standards, decision criteria, and budget allocation decisions Xcel makes. While there are likely hundreds to thousands of individual planning standards and decision criteria Xcel uses, there are larger categories

[25] 2023 IDP Order – Order Point 13.

that are suitable for enhanced analysis. Review of these standards in IDPs is not new; for example, the PNL standard is now under review in its second IDP cycle. The Department simply contends that there are many more standards that need to be reviewed in IDPs, and that a review of these standards should be formalized within the IDP process.

Xcel may counter that large portions of its system planning are not discretionary (Figure 4), which implies that these projects do not require optimization. While the Department does not question the validity of some mandatory spending shown in Figure 4, the Department disagrees on Xcel's use of the term "mandatory." Upstream decision making before budgeting, such as decisions made in forecasting, capacity planning limits, the benefits of reliability, and wildfire mitigations all involve judgment and choice. As the Department will demonstrate in these comments, there is a strong need to evaluate whether Xcel's system planning decisions are in the public interest.

Figure 4: Xcel Presentation of Mandatory VS Discretionary Spending



Source: Xcel Cost Benefit Analysis Workshop 1[26]

B.4. Alignment With IDP Planning Objectives

The analysis of alternative investments and planning standards furthers the cost/system optimization and cost benefit considerations outlined in the Commission's Planning Objectives 4 and 5. This

[26] *Cost Benefit Analysis Workshop 1*, Xcel, Presentation Materials, May 9, 2025, Docket Nos. E002/M-23-452, E002/M-25-142, (eDockets) 20255-218747-01 at Attachment A, 32.

approach complements rate cases and provides a new lens on how costs can be optimized in the distribution system. Therefore, alternatives analysis is fully aligned with the Commission's Planning Objectives.

C. STRATEGIES FOR DISTRIBUTION SYSTEM OPTIMIZATION

The previous section establishes the need for enhanced budgetary scrutiny through the analysis of alternatives and system planning standards. This section describes how Xcel can take additional steps to optimize its distribution system. At no point should the Department's comments be construed to imply that Xcel's distribution system is not already optimized based on its own internal systems, and is therefore imprudent. The Department's recommended strategies in this section are designed to either A) prove that Xcel's planning standards are optimized, or B) offer new strategies to improve optimization.

As a foundational concept, the Department offers its interpretation of what optimization means in the distribution system. Optimization means that every asset on Xcel's distribution system is used to its fullest potential, taking into consideration the maximization of ratepayer value in the process. If Xcel replaces an asset before the end of its useful life and the asset could have been used another year, or two, or five without major consequences, the asset replacement is not optimized. If Xcel sizes a conductor to a ten-year forecast, which then requires a reconductor in year eleven, the conductor sizing is not optimized. If Xcel replaces an asset based on a capacity forecast that is biased, the asset replacement is not optimized. If Xcel installs wildfire mitigations based on a risk assessment that is too high, the system is not optimized. If Xcel assumes blanket benefits for programmatic spending that varies widely by individual project, the program is not optimized. These examples are not hypothetical optimization problems, they are concerns the Department has about Xcel's distribution planning processes.

The Department notes that the consideration of alternatives is discussed in the previous section, while this section introduces a *procedural basis* for the consideration of alternatives.

C.1. Existing Optimization Efforts in the IDP

There is existing precedent within the IDPs to optimize the distribution system. In the context of Xcel, recent optimization efforts have primary taken place regarding PNL, Non-Wires Alternative (NWA) analysis, Targeted Undergrounding, and cost benefit analysis of projects such as Integrated Volt-Var Optimization, for example. However, to date, none of these efforts have delivered meaningful cost savings for Xcel's ratepayers. Despite a lack of cost savings, these studies prove that Xcel's distribution planning assumptions are optimized, at least with regard to these specific alternatives and Xcel's accepted methodology for their implementation.[27]

[27] Other intervenors, including the Department, contend that Xcel's assumptions in some of these areas should be modified.

The only example provided above that has been formally incorporated into the IDPs is NWA, which, by its lack of other examples, demonstrates the lack of formal process regarding optimization. Currently, intervenors are forced to ask information requests and make *ad hoc* recommendations about Xcel's system planning assumptions without a formal presentation of Xcel's system planning. This information asymmetry means that intervenors do not know or understand how Xcel makes decisions, and can therefore not offer alternatives to strategies that are unknown.

C.2. Proof

The most important aspect of alternatives analysis is proof. When Xcel makes generic claims about the efficacy of an alternative to avoid the quantitative analysis of the alternative, Xcel does not provide proof. Without proof, there is no optimization. The Department recognizes that the level of effort to qualitatively describe an outcome compared to the quantification of its effects requires substantially less effort, and these tradeoffs should be considered, where appropriate. However, the default option should always be for Xcel to demonstrate, with evidence, why an alternative is appropriate or not. Only in cases where the outcome is obvious and indisputable, should Xcel forgo any type of quantitative analysis.

To date, many alternative outcomes presented in recent IDPs have been qualitative in nature. Xcel's Targeted Undergrounding Proposal demonstrates this deficit. Xcel plans a budget of $233.7 million,[28] and does not provide a quantitative analysis of vegetation management. Instead, Xcel says, "[t]he Company currently does not have data to quantify the reliability benefits or duration of impact from enhanced vegetation management."[29] The Department does not think it is reasonable to request a $233.7 million budget without quantitative due diligence, particularly because vegetation is the leading source of outages for Xcel.[30] Regardless of the outcome of enhanced vegetation management, Xcel should be able to prove why the strategy is or is not beneficial with quantitative analysis.

C.3. Cost Benefit Analysis

While the Department continues to support cost benefit analysis, whenever feasible, the analysis is not essential for the optimization process. Rather, cost benefit analysis represents the highest formalization of proof. Cost benefit analysis is best suited to two use cases. The first use case is for cost recovery proceedings. The benefit of cost benefit analysis in this context is obvious and is also typically practiced by most utilities in cost recovery proceedings for larger investments. Cost benefit analysis provides a firm justification for utility investments to prove that the investments are prudent.

The second use case is for program evaluation. Xcel presents a cost benefit analysis of two of its existing programs for evaluation within this IDP for its End of Life Replacement (ELR) – Breakers

[28] 2025 IDP – Chapter 2 at 6.
[29] *Id*., at Chapter 2, 12.
[30] *In the Matter of Northern Sates Power Company's Annual Report on Safety, Reliability, and Service Quality for 2024*, Xcel, Compliance Filing, April 1, 2025, Docket No. E002/M-25-27, (eDockets) 20254-217138-03 at Attachment I, 1.

Program and for its Grid Reinforcement Program. To the Department's knowledge, these two analyses represent the first cost benefit analyses of existing programs within the IDPs. A review of existing programs at some cadence is essential, because as the Department will demonstrate later in its comments, both of these programs are marginally cost effective, at best. Therefore, analysis of existing programs highlights areas where Xcel should allocate more or less money to existing programs.

Program evaluation also allows Xcel to compare the cost effectiveness of programs with similar outcomes, such as reliability. As comparative cost benefit analysis also extends temporally, a program that may have been cost effective at one point in time may no longer be cost effective due to changes in labor or material costs, such as the rising cost of transformers. As conditions change, it is important to evaluate program cost effectiveness over time.

The Department recommends the Commission order Xcel to provide an update to each program cost benefit analysis ten years after the initial presentation of the cost benefit analysis.

The Department emphasizes that the purpose of program evaluation is to explore the justification of future programmatic expenses and will never be used to justify the disallowance of cost recovery that may be found to be cost ineffective during program evaluation. If a program, or part of its expenses, is found to be cost ineffective, the Department would recommend that these costs no longer be allowed for future cost recovery proceedings.

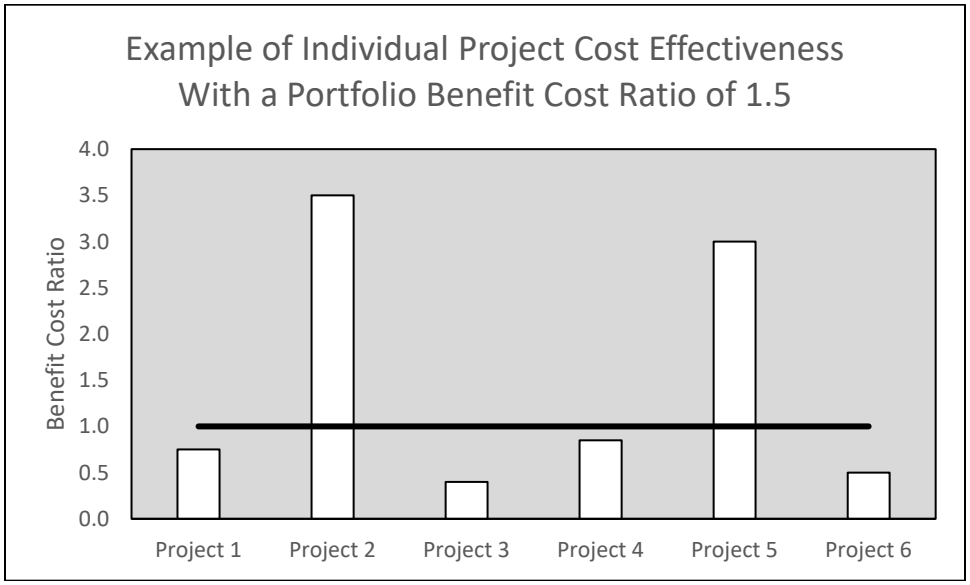
The Department supports Xcel's "walk-jog-run" approach, and recommends that Xcel continue to provide additional cost benefit analysis of programs that the Company considers to be discretionary. With Xcel's demonstration that the Company can provide this analysis, the Department recommends a higher scope of analysis for the next IDP cycle.

The Department recommends the Commission order Xcel to provide a cost benefit analysis of at least three discretionary programs with a total five-year budget of at least $250 million.

C.4. Enhanced Granularity

Optimization can only take place if the analysis of decisions occurs at a sufficient level of granularity. While programmatic evaluation is useful to provide a general impression of cost effectiveness, it can obscure cost-ineffective investments when some projects have much higher benefits than others. Figure 5 demonstrates an example of the importance of granularity in the optimization process. The figure shows a portfolio average benefit cost ratio (BCR) of 1.5. Of the six projects listed, only two projects have a BCR of at least 1.0, while the remaining four projects are not cost effective. This example illustrates that the hypothetical program is not optimized for individual projects, and therefore spends money on projects that are cost ineffective. In this example, an optimized program would only proceed with Projects 2 and 5.

Figure 5: Example Comparison of Individualized Cost Benefits Compared to a Portfolio Estimate



The Department highlights this concept in subsequent comments and makes specific recommendations regarding individualized project metrics in subsequent sections.

C.5. Sensitivity Analysis

A large part of the optimization process lies within sensitivity analysis. Sensitivity analysis demonstrates the effects of different key input assumptions. For example, if an assumption is uncertain, then sensitivity analysis may reveal that a 25% reduction in an expected outcome could make a proposed measure cost ineffective, or vice versa. Many utility assumptions, particularly when presented in a cost benefit analysis, are assumed to be static, despite uncertainty in these estimates. It may be revealed that small changes in assumptions or standards could result in large shifts in utility budgets. For example, if Xcel were to change its N-0 feeder capacity planning standard from maximum load to rated capacity from 75% to 80%, the number of at risk feeders would drop from 27.1% to 20.9%,[31] which is a 22.9% reduction that results from a 6.7% change in an input parameter. While a 5% change in Xcel's capacity planning standard could result in more outages, it is conceivable that the value of outages is not as great as the value of reduced asset replacement before the end of an asset's useful life.

Similarly, changes to a utility's planned budget could have a large impact on how system risks are mitigated. For example, when the Department asked Xcel how a double- or half-vegetation management budget would impact customer outages, the Company responds:

[31]See Figure 6 below for more information. Attachment B – DOC IR 34, Attachment A. Note that Attachment A is not included in these comments, but can be provided upon request.

> 1. Doubling the current vegetation management budget could improve annual customer minutes of interruption by approximately 10 to 40 million minutes compared to current plans.
>
> 2. Reducing the budget by half could degrade annual customer minutes of interruption by approximately 100 to 300 million minutes compared to current plans.[32]

Xcel's estimate, which the Company notes is speculative and uncertain, demonstrates the marginal impact of increased spending compared to the much larger impact of decreased spending. While Xcel does not know the actual impact of changes in its vegetation management budget, this dynamic may be at play in other budgets as well. For example, if Xcel devotes more money to a budget category that is already well optimized, and does not have significant gains to achieve, then the money may not produce a marginal benefit that is worth the marginal cost, or vice versa.

These examples highlight the importance of sensitivity testing of both Xcel's decision criteria as well as its budgets.

C.6. Expected vs Actuals

While forecasted benefits of utility investments are highly useful for decision making purposes, it is equally as important to evaluate actual outcomes of new utility investments. Reporting on actual outcomes of utility spending indicates whether expected outcomes are achieved or not. If the outcomes are not achieved, the program may not be cost effective, and should be discontinued; conversely, if outcomes are better than forecasted, then additional spending may be justified. Actual outcomes also help future decisions with improved alternatives analysis, which may reveal that programs that achieve greater outcomes than expected may be viable alternatives to other investments.

The Department recommends the Commission order all new Xcel spending projects with a five-year budget over $25 million, that were approved for cost recovery since 2021, report five years of actual outcomes compared to forecasted outcomes in the IDP.

C.7. IDP Review of Major New Expenses

As discussed previously, the rate case is not the appropriate venue to optimize distribution planning. Xcel's pursuit of wildfire spending is a perfect example of the need for optimization of the program within the IDP. Xcel circumvented the IDP process entirely with its rate case request for cost recovery. While the Company filed a letter agreeing to the Department's recommendations and to reduce Xcel's

[32]Attachment B – DOC IR 53. Xcel notes its objection to the Department's information request as inherently speculative. Xcel states that its estimates are very uncertain.

budget request in the rate case,[33] the plan should have been filed in the IDP before Xcel sought cost recovery. Xcel's requested wildfire budget would have failed most of the optimization measures discussed previously. In addition, the request neither establishes nor proves a quantifiable wildfire risk, nor does it attempt to quantify benefits. The request also does not establish individual project benefits. While the Department offered comparative risk assessments in its testimony,[34] the rate case process does not allow for as detailed of a review and opportunity to optimize the proposal. These are a few examples where greater due diligence could occur in the IDP process, if there is a willingness to modify the IDP process.

The Department notes that nothing in existing IDP filing requirements or other Commission approved process prevents a utility from circumventing the IDP process and requesting cost recovery first. Additionally, the Department does not advocate here for IDPs to become rate cases; rather, it contends that utility proposals for large new spending proposals undergo review in the IDP for a more robust and optimized plan before a distribution cost recovery request is made in a cost recovery proceeding. While utilities cannot be required to submit their plans for future cost recovery requests in the IDP before cost recovery can be approved, the exclusion of feasible alternatives or appropriate sensitivity analysis in a cost recovery proceeding can be used to justify that proposed spending is imprudent.

The Department recommends that the Commission create a new filing requirement which states: All new distribution spending projects and programs with an estimated historical or forecasted five-year budget of $25 million or greater shall, at minimum, address the following:

- **A. Estimated cost or range for the project/program;**
- **B. Consideration of feasible alternatives to the proposed spending;**
- **C. Quantitative estimation of expected outcomes; and**
- **D. Sensitivity analysis of cost and outcome assumptions.**

The establishment of the above filing requirement would both require large project optimization within the IDP and would request a good faith effort by Xcel to vet its large cost recovery plan within the IDP before making a cost recovery request. In the circumstance of Xcel's wildfire spending, the filing requirement would require Xcel to conduct A-D on its existing wildfire program, and the results of this analysis would be used in future cost recovery proceedings to determine the appropriate level of funding. Therefore, should Xcel choose to forgo preliminary analysis in the IDP, it is still required to perform a post-hoc optimization.

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[33] *In the Matter of the Application of Xcel Energy for Authority to Increase Rates for Electric Service in Minnesota CAH No. 28-2500-40515*, Xcel, Letter, December 12, 2025, Docket No. E002/GR-24-320, (eDockets) 202512-225801-01.

[34] *In the Matter of the Application of Xcel Energy, for Authority to Increase Rates for Electric Service in Minnesota,* Surrebuttal Testimony and Attachments of Eric Borden, Department, November 25, 2025, Docket No. E002/GR-24-320, (eDockets) 202511-225277-03, (hereinafter: "Borden Surrebuttal") at 18-22; *In the Matter of the Application of Xcel Energy, for Authority to Increase Rates for Electric Service in Minnesota,* Direct Testimony and Attachments of Eric Borden, Department, November 25, 2025, Docket No. E002/GR-24-320, (eDockets) 20258-222346-11 (hereinafter: "Borden Direct") at 11-12.

C.8. Review of Planning Standards

Most of the decisions that Xcel makes regarding its system planning are not discussed within the IDP. These decisions collectively result in Xcel's distribution budget request, and can circumvent the need to derive the causes of spending increases, which requires far more data. As an example, one of Xcel's most impactful planning standards is its N-0 and N-1 capacity standards. Table 1 summarizes the planning standards, which shows that 15 kV feeders should not be loaded more than 75 percent, in order to allow for switching, such that the load on a faulted feeder can be transferred to adjacent feeders without loss of load.

Table 1: Summary of Xcel's Capacity Planning Standards

Table 1 - 12
Risk Thresholds Requiring Mitigations

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

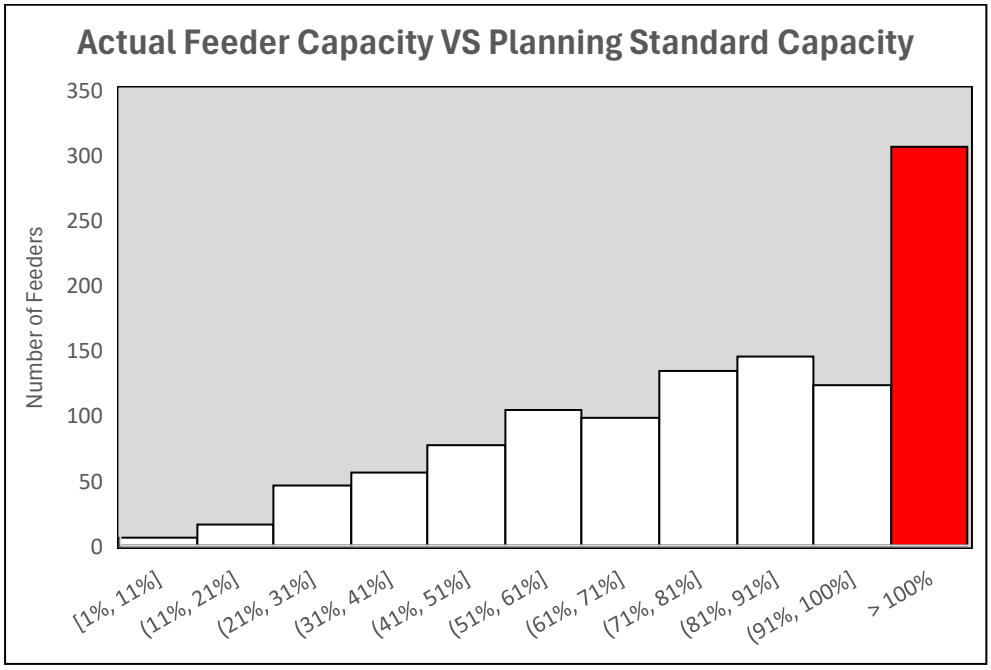
Xcel describes N-1 risk as follows:

> Distribution Planning delivers an N-1 Contingency Analysis, which is a list of all feeders and substation transformers for which the loss of that feeder or transformer results in an overload on an adjacent feeder or transformer, or loss of service for customers. For example, a 1.5 MVA N-1 condition for feeder FDR001 means that for loss of FDR001, all but 1.5 MVA of FDR001's peak load can be safely transferred to adjacent feeders without causing an overload. The remaining 1.5 MVA that cannot be transferred is then referred to as "load at risk." This risk reflects the ability of the system to be reconfigured to serve all the load. Any N-1 risk means that the N-1 analysis determined that there was not sufficient redundancy to supply the electricity demand once a given element has been lost. The Customers subjected to this N-1 outage would be without power until repairs are made, and the system is restored to an N-0 state.[35]

While Xcel may argue that these planning standards cannot be modified, these assertions are easily refuted by Xcel's own data. Figure 6 shows that 27 percent of Xcel's existing feeders are currently exceeding Xcel's planning standard, which indicates that the Company decided to not fully enforce its own planning standards.

[35] 2025 IDP – Chapter 1 at 82-83.

Figure 6: Comparison of Actual Feeder Capacity to Xcel's N-0 Capacity Planning Standard



Source: Department IR 34

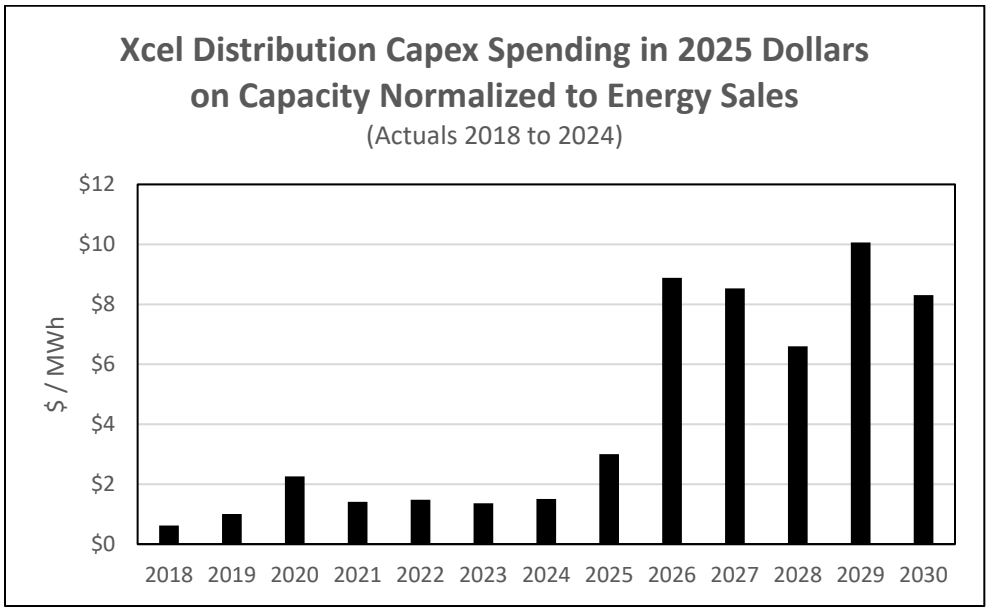
The 75 percent N-0 feeder planning standard has the potential to add significant cost to Xcel's budget. Compared to a 100 percent planning standard, the N-0 standard requires an additional one third of extra feeder capacity as headroom, which not only means that Xcel may oversize new equipment, but it also may trigger capacity upgrades before they are necessary, both of which may inflate Xcel's capacity budget. The Department asked Xcel if the Company has performed any cost-effective analysis of its N-0 and N-1 capacity planning standards, and the Company states:

> The Company has not completed a cost-effectiveness analysis of the N-0 and N-1 load limit risk thresholds in Table 1-12. Accordingly, there are no analyses to provide in Excel format. The Company's planned loading limits are established based on engineering analysis and system design, not cost-effectiveness.[36]

This review demonstrates that A) Xcel makes discretionary decisions regarding its capacity planning standards, and B) Xcel does not know whether these planning standards are cost effective. In addition, Xcel's LoadSEER forecast used for capacity planning may significantly overestimate capacity needs, which can trigger upgrades before they are necessary, with a year 2 forecast error of 10.1 percent.[37] The importance of these planning standards cannot be overstated, as Xcel's inflation-adjusted capacity budget is expected to more than quadruple compared to historical levels, after adjusting for energy sales, which is shown in Figure 7.

[36] Attachment B – DOC IR 66.
[37] Department Initial Comments on Xcel's Proactive Upgrade Proposal – at 4-9.

Figure 7: Xcel Capacity Spending Adjusted to Energy Sales

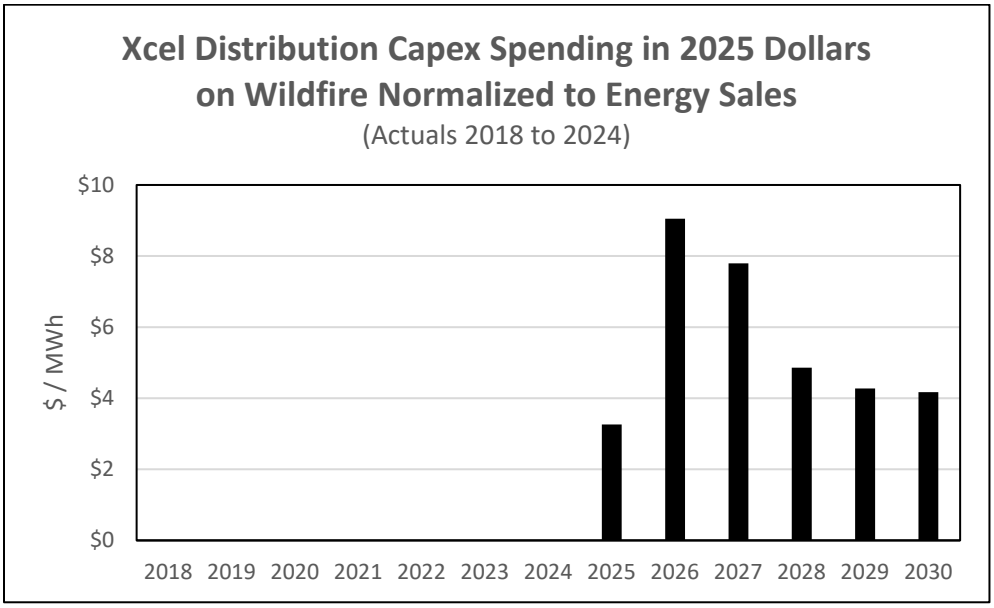


Source: 2025 IDP – Attachment L, IR 32, IR 33, IR 37

The Department continues its discussion of Xcel's capacity budget and planning assumptions in Section III.G.

Xcel's wildfire spending is also expected to rise from zero to a spending level on par with that of Xcel's capacity budget, which is shown in Figure 8. Together, these two budgets account for 41.6% of Xcel's total capex budget between 2025 and 2030, and both budgets are rising at alarming rates.

Figure 8: Xcel's Wildfire Budget Adjusted to Energy Sales



Source: 2025 IDP – Attachment L, IR 32, IR 33, IR 37

The Department continues its discussion of Xcel's wildfire budget in Section III.H.

The Department reiterates that the evidence presented in this section does not mean that Xcel has planned its system imprudently. These examples highlight the need for review of Xcel's planning assumptions. On the capacity-side, Xcel's planning standards may trigger upgrades before or at the end of life. Regarding end-of-life replacement, Xcel states:

> The appropriate design horizon depends on the type of project and system conditions. For example feeder-level projects may only use a 5-10 year horizon, while larger infrastructure additions—such as new substations or transformer additions—are generally designed to meet needs across a 10-30 year horizon.[38]

These new asset planning standards may also be problematic for cost optimization, as Xcel states:

> Across all three scenarios, the forecast shows distribution system growth from approximately 8.5 GW today to between 9 and 10 GW by 2035. This projected increase of 0.5 to 1.5 GW over the next ten years is substantial. To put this into perspective, a 1 GW increase would require *at least* 10 new substations, 20 new substation transformers, and 150 new feeders to support the additional load.[39]

[38] Attachment B – DOC IR 70.
[39] 2025 IDP – at 7.

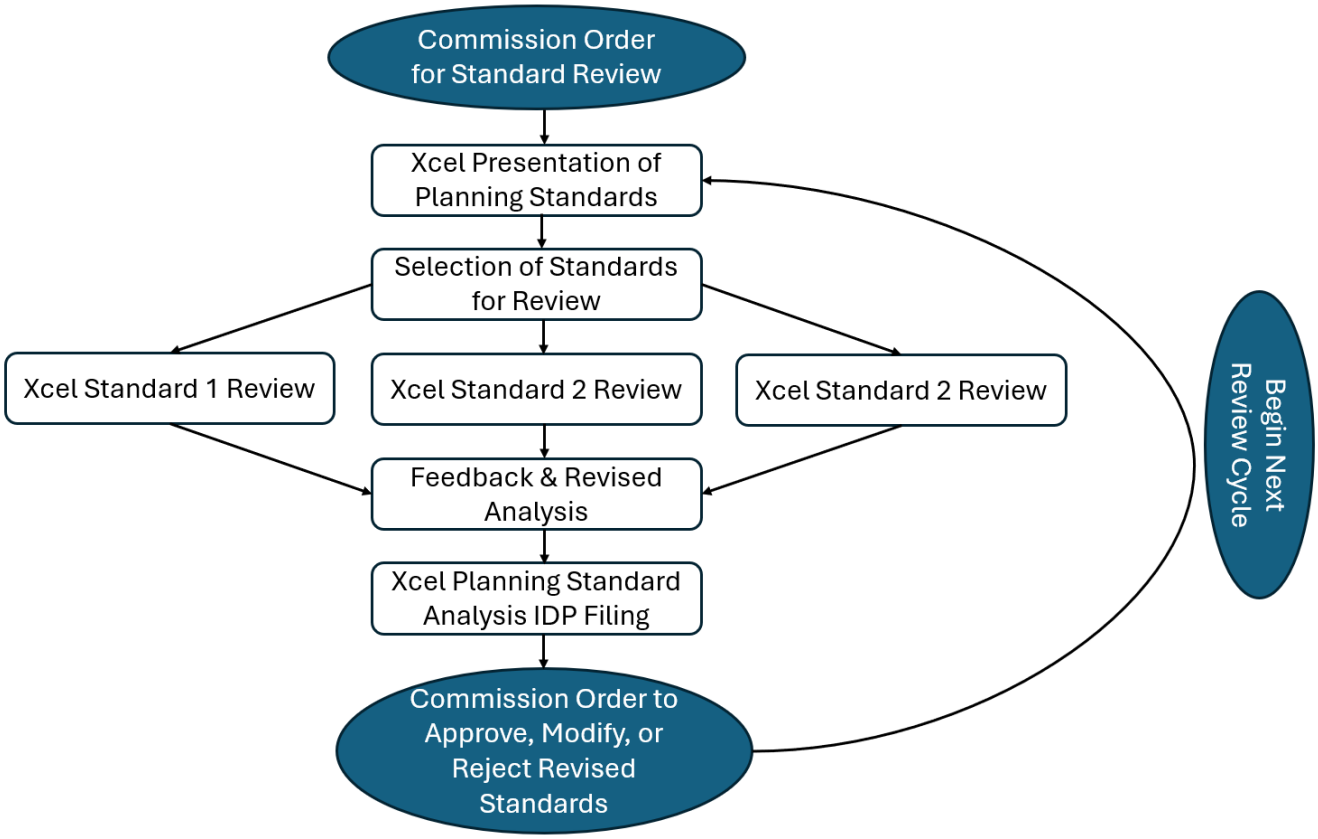
If Xcel continues to size its feeders to meet a load expectation in 5 or 10 years, it may in fact undersize its system and require several rounds of infrastructure upgrades to meet its planned load growth when the Company could instead size its assets during replacement for a longer-term forecast of capacity.

The Department does not know what the optimized capacity planning standards should be; but rather it demonstrates that these standards are not optimized for cost. The Department prefers a nuanced review of Xcel's planning standards, in coordination with Xcel engineers, to weigh the costs and benefits of Xcel's capacity planning standards regarding cost and the increased risk of outages.

The Department envisions the creation of a cyclical planning standard review process that takes place over four phases, with one phase per IDP. For the first phase, Xcel's capacity and wildfire system planning standards would be reviewed. For the second phase, Xcel's reliability and asset health planning standards would be reviewed. For the third phase, Xcel's grid modernization, DER, and operation and maintenance (O&M) planning standards would be reviewed. For the final phase, Xcel's budget allocation standards would be reviewed. These cycles would repeat every eight years to test the performance of existing, new or revised standards and would determine whether further modifications are necessary.

The review process would entail several sub-processes. The first step would be a presentation of Xcel's main planning standards for each topic area, such as capacity. The review is not intended to scrutinize every decision Xcel makes, but rather should provide a comprehensive overview of key decision points, particularly if those decision points impact the budget. The Department clarifies that many planning standards may be viewed as static by Xcel, and Xcel engineers should identify areas that cannot be modified. The second step would involve the selection of one or more planning standards to review. In this step, Xcel and intervenors would decide how many standards can be reviewed before the next IDP. After selection, Xcel and intervenors would decide on a set of alternative planning standards for analysis. In the next step, Xcel would present analysis of the alternative planning standards, and these standards could be modified in a second cycle, or could be presented in the next IDP. After the selection and review of planning standards, Xcel would present the results of its review in its next IDP. The Commission would request comments to approve, modify, or reject the new planning standards, and would then issue a the relevant order. The process is summarized in Figure 9.

Figure 9: Summary of Planning Standard Review and Approval Process



The Department recommends the Commission create a planning standard review process that shall:

A. **Identify the main system planning standards that Xcel uses for each Commission-approved review topic;**
B. **Select one or more planning standards, in agreement with intervenors, to review before the next IDP;**
C. **Set alternative system planning scenarios to analyze, in agreement with intervenors;**
D. **Perform a quantitative analysis of alternative system planning standards that measure estimated costs and benefits of alternative system planning standards;**
E. **Require Xcel to present the results of steps A-D in the next IDP cycle; and**
F. **Request comments to approve, modify, or reject the revised system planning standards for each Commission-approved review topic.**

The Department recommends the Commission establish the following system planning standard review schedule, with each phase to repeat every eight years:

- **2027: Capacity and Wildfire**
- **2029: Reliability and Asset Health**
- **2031: Grid Modernization, Distributed Energy Resources, and Operation and Maintenance**
- **2033: Budgeting**

If approved, the review cycle would begin after the Commission's approval of Xcel's 2025 IDP and Xcel would begin review of its Capacity and Wildfire planning standards for the 2027 IDP.

The Department is cognizant that the review schedule, on its own, may be too inelastic to keep up with changes to the distribution system. While the Commission already allows system planning standard reviews, for example PNL, there is no formal process to track or approve these reviews. The Department suggests formalizing this process to the benefit of all parties. Under the Department's proposed system, any intervenor may request a planning standard review for a new or modified planning standard that the Commission would approve, modify or reject. Any approval would then require Xcel to present the results of its system planning standard review in the next IDP, where the Commission would approve, modify, or reject the planning standard. Unlike in the cyclical review process, these requests should be highly specific and would not require involvement from intervenors between IDPs.

The Department recommends the Commission establish an ad hoc system planning standard review process that shall:

A. **Allow any intervenor to request a planning standard review;**
B. **Set the parameters that shall be reviewed;**
C. **Require the Commission to approve, modify, or reject the request for a planning standard review;**
D. **Require Xcel to present the results of the planning standard review in its next IDP; and**
E. **Request comments to approve, modify, or reject Xcel's system planning standard.**

For this process to be effective, Xcel must disclose changes to its system planning standards in its IDP. It is not necessary to prescribe additional processes beyond disclosure, because the ad hoc process, described above, can be used to approve, modify, or reject the system planning standard change, at the request of an intervenor.

The Department recommends the Commission order Xcel to disclose all changes to its system planning standards in its IDP.

The Department recognizes that the definition of "system planning standard" is subjective. The Department does not want or intend to scrutinize every decision Xcel makes on its distribution system. Nor does the Department suggest to substitute its judgment for that of skilled distribution system engineers. While there are perhaps hundreds or thousands of standards Xcel uses to plan its distribution system, the Department is primarily interested in standards that relate to risk and probability, particularly those standards for which modification could result in a material change to Xcel's budget in the tens of millions of dollars. The Department does not consider explicit safety standards, such as breaker or conductor sizing, to be under the umbrella of system planning standards. Instead, the Department is interested in standards that cover areas where judgment is exercised. The N-0 and N-1 capacity standards are perfect examples of system planning standards the Department

would like to further analyze. The Department does not dispute the need to mitigate capacity needs that reach or exceed the 100 percent capacity rating. However, the remainder of the standards remain more hypothetical, such that peak load events may not coincide with N-1 events, or that an infrequent loss of load event may be economically preferrable to a system overbuild. For purposes of discussion, the Department provides its own definition a system planning standard:

> A rule, guide, or decision criterion that governs a broad range of distribution planning activities beyond actions taken with regard to a single piece of equipment or project, and where its modification would not result in the immediate failure of system equipment.

Finally, the Department acknowledges the significant resources that Xcel devotes to the IDP process, and how additional process recommendations could further strain Xcel's distribution planning efforts. However, the Department also thinks that such a significant effort should result in actionable outcomes. To offset additional process, several of Xcel's current IDP filing requirements could be removed to focus on system planning standard analysis.

The Department recommends the Commission order the Executive Secretary to create a work group to identify IDP filing requirements that Xcel and intervenors agree can be removed.

D. FORECASTED DISTRIBUTION BUDGET

The Department responds to the following notice topic:

> *Notice Topic 16.A: Feedback, Comments, and Recommendations on the forecasted distribution budget.*

D.1. Spending vs Rates

Utility spending and rates are two different, but related concepts. Utility spending is a straightforward concept, which totals all the money the utility plans to spend during a specified period of time. Rates are the costs that are passed onto ratepayers to recover costs from spending. Increases in utility spending may not be commensurate with rate increases, because rates can be designed to capture the ebb and flow of spending, providing a more even distribution of spending. Additionally, the capital spending budgets presented by Xcel are only capitalized costs. Actual cost recovery, or resulting revenue requirements, could be two to three times higher over a potentially 50-year depreciation window, after adding the weighted cost of capital, taxes, and other related expenses. While spending does not equal rates directly, an analysis of utility spending can be helpful in analyzing the impact on utility rates.

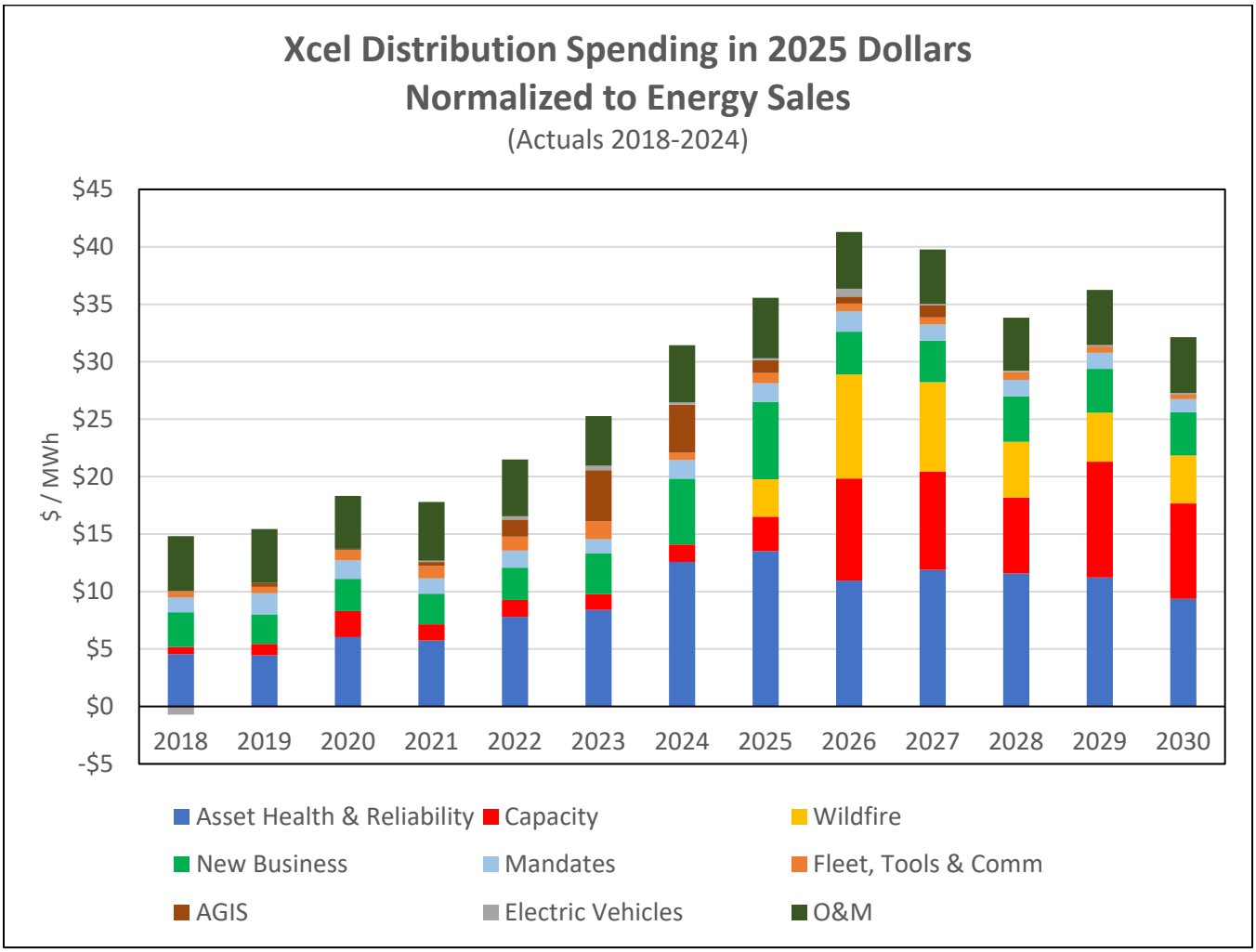
Regardless of rate impacts, every additional dollar that Xcel spends or saves puts upward or downward pressure on rates. Every year that a utility asset remains on Xcel's system (because it is not retired) is another year that Xcel does not have to spend money to replace the asset, regardless of whether the asset is depreciated or not.

D.2. Summary of Budget Trends

Xcel prepares a five-year financial forecast for the years 2026 through 2030. The key components of the financial forecasting process include the O&M budget and the capex budgets.

Figure 10 shows Xcel's distribution spending in 2025 dollars, normalized to energy sales and covering the years 2018 to 2030. Xcel's distribution spending for the years 2018 through 2024 are based on actual budget expenditures and the data for the years 2025 through 2030 are based on forecasted budget expenditures. The greatest spending increases occur in the following three spending categories: Asset Health and Reliability, Capacity, and Wildfire Mitigation.

Figure 10: Trend in Xcel Distribution Spending Over Time



Source: 2025 IDP – Attachment L, IR 32, IR 33, IR 37

D.3. Asset Health and Reliability

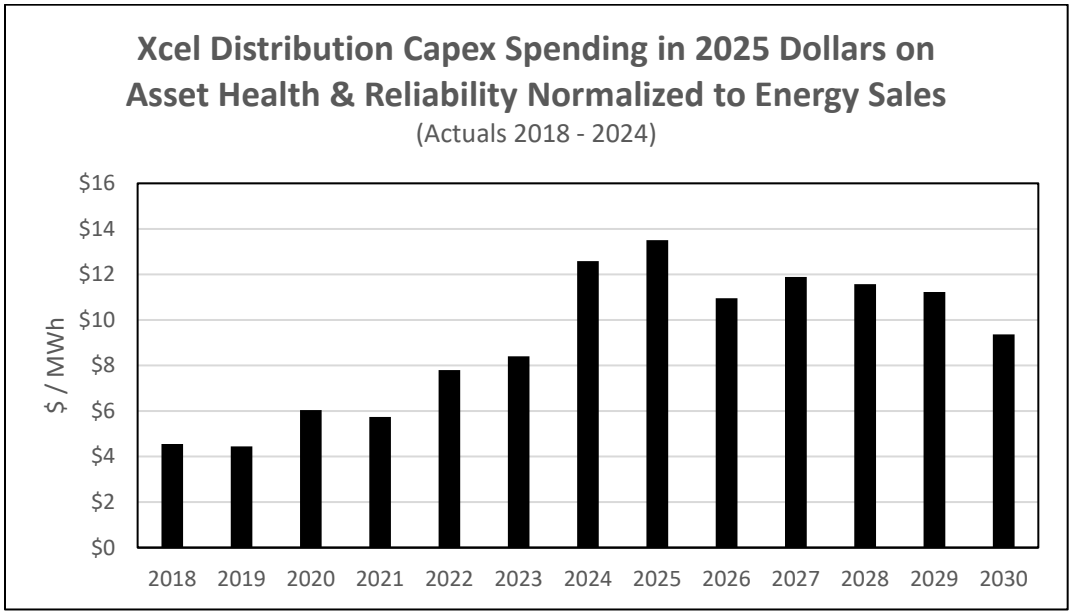
In its IDP, Xcel states that Asset Health and Reliability:

> includes projects focused on replacing infrastructure that has high failure rates, which can reduce service reliability and increase O&M costs. When underperforming assets are identified, [Xcel] budget[s] for projects that will improve their performance. Typical projects include the replacement of underground cables, wood poles, overhead lines, substation equipment, transformers, and switchgear that have reached the end of their useful life. This category also covers replacements necessitated by storm damage or public interference.[40]

Asset Health and Reliability is Xcel's largest budget category. Figure 11 shows Xcel's Asset and Reliability spending, in 2025 dollars, normalized to energy sales and covering the years 2018 to 2030. The Xcel Asset and Reliability spending for the years 2018 through 2024 are based on actual numbers and the data for the years 2025 through 2030 are based on forecasted numbers. Figure 11 shows the recent jump in spending on Asset Health and Reliability and the forecasted higher level of spending for the next several years. Spending was stable from 2018 through 2021, began an upward climb during the years 2022 and 2023, and then jumped in 2024 to a much higher forecasted level through 2030. Xcel's actual historical Asset Health and Reliability budget, for the years 2020 through 2024 (in 2025 dollars), totals $1.09 billion. Xcel's total forecasted Asset Health and Reliability budget, for the years 2026 through 2030 (in 2025 dollars), grows to a total of $1.47 billion. This data shows an increase of 35% from the total historical Asset Health Reliability budget for the 2020 to 2024 period to the forecasted Asset Health and Reliability budget for the 2026 to 2030 period.

[40] 2025 IDP – Chapter 6 at 4.

Figure 11: Xcel Asset Health & Reliability Spending Adjusted to Energy Sales



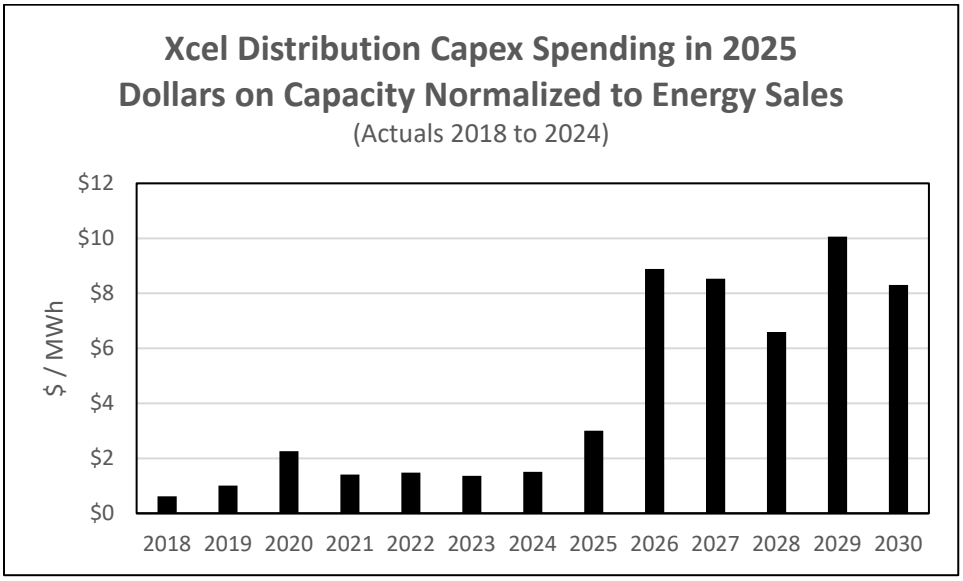
Source: 2025 IDP – Attachment L, IR 32, IR 33, IR 37

D.4. Capacity Budget/Spending

Capacity refers to capital investments designed to expand or upgrade the distribution system to support load growth from both existing and new customers. Projects typically include installing new or upgraded substation transformers and distribution feeders. These capacity-related projects often span multiple years and are driven by increasing load demand. Programs such as grid reinforcement, and feeder load monitoring are also included here.[41] Figure 12 shows these Capacity spending trends, in 2025 dollars, normalized to energy sales covering the years 2018 to 2030. The Xcel Capacity spending for the years 2018 through 2024 are based on actual numbers and the data for the years 2025 through 2030 are based on forecasted numbers. Xcel's distribution spending on Capacity was stable, at a relatively moderate level from 2018 through 2024, is forecasted to begin climbing in 2025, then to significantly increase until at least, 2030, as shown in Figure 12. Xcel's actual historical Capacity budget, for the years 2020 through 2024 (in 2025 dollars), totals $215.50 million. Xcel's total forecasted Capacity budget, for the years 2026 through 2030 (in 2025 dollars), grows to a total of $1,132.38 million. This spending results in an increase of 425 percent from the total historical Capacity budget for 2020 to 2024 period to the forecasted Capacity budget for 2026 to 2030 period.

[41] 2025 IDP – Chapter 6 at 4.

Figure 12: Xcel Capacity Spending Adjusted to Energy Sales



Source: 2025 IDP – Attachment L, IR 32, IR 33, IR 37

D.5. Wildfire Mitigation

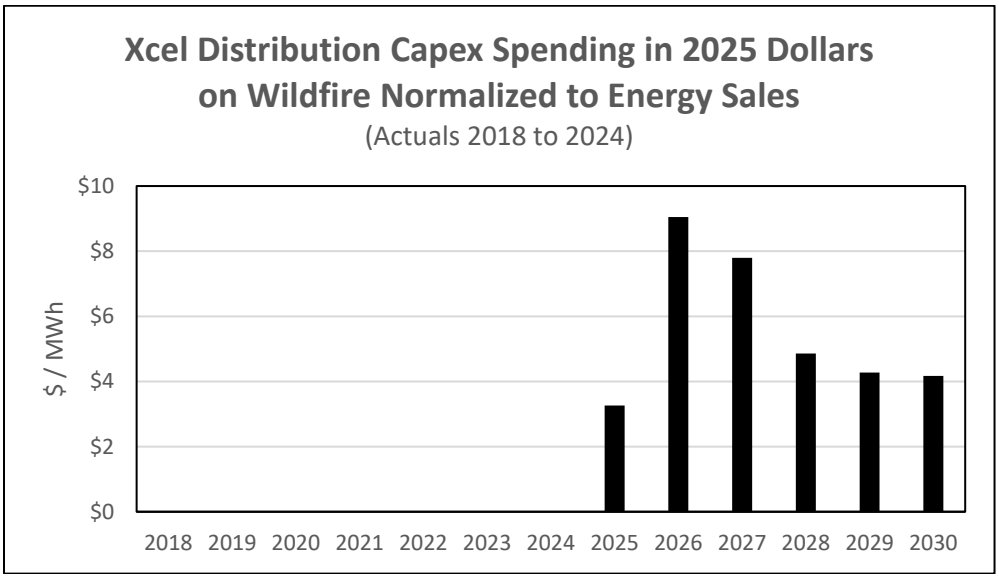
Wildfire Mitigation includes:

> [T]he Company's investments related to mitigating the risk of wildfires, including investments in operational mitigations, overhead assessments and associated mitigations, and small conductor and pole replacements, all targeted to reduce wildfire ignition risk in the wildfire risk areas of the Company's Minnesota service territory. In addition to reducing ignition risk, a portion of these investments, such as small conductor and pole replacements, address some of the oldest assets on [Xcel's] system, serving to preserve the integrity and functionality of the system components now and into the future.[42]

Figure 13 shows these trends in Wildfire spending, in 2025 dollars, normalized to energy sales covering the years 2018 to 2030. The Xcel Wildfire spending for the years 2018 through 2024 are based on actual numbers and the data for the years 2025 through 2030 are based on forecasted numbers. Xcel did not allocate funding to Wildfire Mitigation from 2018 through 2024. However, it is forecasted to increase significantly in 2025, then to jump in 2026 and stay at a higher level until 2030, as shown in Figure 13. Xcel's actual historical Wildfire budget, for the years 2020 through 2024, totals $8 million (in 2025 dollars). Xcel's total forecasted Wildfire budget, for the years 2026 through 2030 (in 2025 dollars), grows to a total of $803.05 million.

[42] 2025 IDP – Chapter 6 at 35.

Figure 13: Xcel Wildfire Spending Adjusted to Energy Sales



Source: 2025 IDP – Attachment L, IR 32, IR 33, IR 37

As the figures referenced in this section demonstrate, Xcel forecasts significant increases in spending on Asset Health and Reliability, Capacity, and Wildfire Spending. The Department further discusses the increases in spending in these categories, along with its recommendations in other sections of the current comments.

E. VALUE OF RELIABILITY

The value of reliability is a foundational concept to understand how reliability projects impact Xcel's budget. This concept is used throughout Xcel's analysis of project benefits, including:

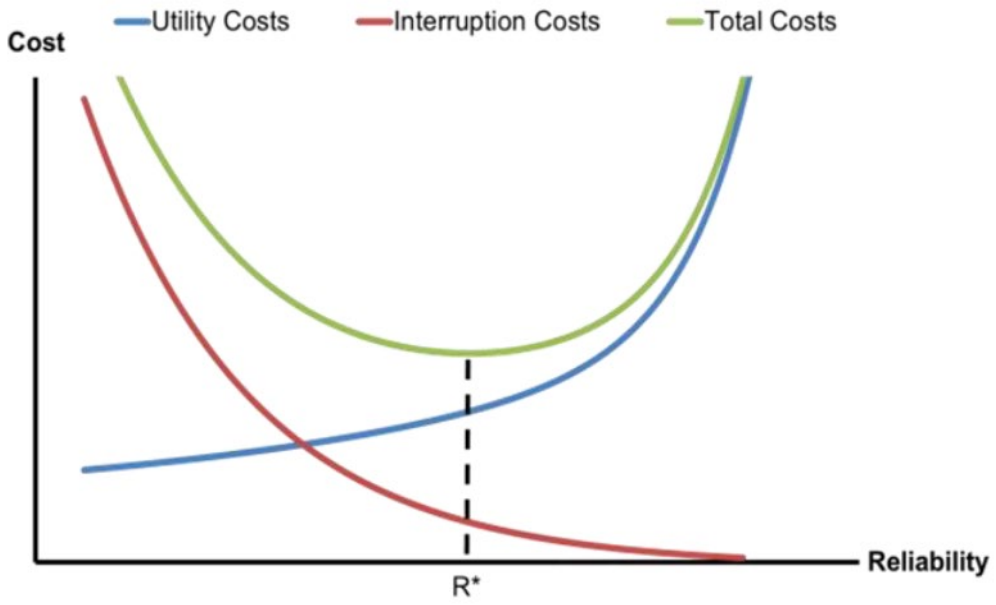
A. Targeted Undergrounding Proposal
B. Capacity Risk Model
C. End of Life Replacement Program CBA
D. Grid Reinforcement Program CBA

Reliability mitigations typically increase utility costs. A good example of increased costs from reliability spending relates to overhead vs underground power lines. Xcel estimates that new build underground powerlines are almost twice as expensive to build as overhead lines,[43] but underground lines significantly improve reliability. The distribution budgeting process should optimize for societal costs, which internalizes the cost of power outages into the reliability budget. Figure 14 shows how additional utility spending to improve reliability spending increases ratepayer costs, but can decrease societal costs (total Costs borne by customers) if these costs are appropriately optimized. However, if a

[43] Attachment B – DOC IR 96.

utility spends too much money to improve reliability with marginal decreases in improvement, costs are not optimized.

Figure 14: Internalization of Reliability Costs to Utility Spending



Source: Figure 2-1 LBNL Estimating Power System Interruption Costs[44]

Xcel monetizes the value of outages by applying a monetization conversion of customer minutes out (CMO). CMOs are multiplied by a $3.05 / CMO[45] conversion factor to determine the value of outages.[46] The monetization value is derived from the Lawrence Berkeley National Laboratory (LNBL) Interruption Cost Estimator (ICE) tool.[47] LBNL explains how the concept of reliability monetization works:

> Utilities must balance the economic costs of their investments against the economic value that customers receive from those investments—i.e., the value of service (VOS) created. If spending on reliability and/or resilience exceeds the economic impacts that are avoided by these investments, the cost (and price) of electricity will increase unnecessarily. Conversely, if utilities invest too little on reliability and/or resilience, customers will experience expensive and unnecessary interruption costs and inconvenience that could have been avoided.

[44] Sullivan, Michael, Myles T. Collins, Josh Schellenberg, Peter H. Larsen. *Estimating Power System Interruption Costs: A Guidebook for Electric Utilities*. Lawrence Berkeley National Laboratory, (July 2018). At 10. Available at: https://eta-publications.lbl.gov/sites/default/files/interruption_cost_estimate_guidebook_final2_9july2018.pdf
[45] Xcel also uses a $3.11 / CMO value for all its jurisdictions in other areas of its IDP.
[46] 2025 IDP – Attachment D at 1.
[47] *Id*., at Chapter 2, 14.

> […]
>
> VOS is the economic value that customers receive from reliability or resilience. It is expressed in a variety of ways, such as $/unserved kWh or $/customer-minute interrupted. These types of VOS measures are often expressed as averages or sums across all customers in a given utility. Underlying these aggregate values are the VOS quantities for each customer. The value that customers place on service varies considerably by customer type, as certain customers have higher VOS than others. For example, a residential customer may not incur significant costs or be inconvenienced by frequent, short duration interruptions, while a large industrial customer may incur substantial costs from loss of production from even a single momentary outage. VOS also varies among customers even within the same customer class. A stay-at-home parent may have a very different VOS than a day trader operating out of his/her home. These examples could all be located on the same circuit within a utility's service territory—and there is a wide variation in VOS across circuits. Utilities thus have significant opportunities to optimize investments by targeting high-value circuits, or circuits with high costs of unreliability.[48]

The Department emphasizes that the reliability benefit varies considerably based on which class of customer receives the benefit. The difference in potential costs is highlighted by the large divergence in values between residential and non-residential customers. Xcel's IR 45 response shows that Xcel assumes a residential CMO value of $0.08 / CMO and a non-residential CMO value of $30.65 / CMO.[49] Xcel assumes that 10.07% of its customers are non-residential, and the weighted average of these CMO values results in the $3.05 / CMO that Xcel uses in its calculation of reliability benefits. To highlight how important the assumption of customer class is, if the number of non-residential customers drops to 5% or increases to 15%, the interruption value changes to $1.61 / CMO and $4.67 / CMO, respectively. A five-percentage-point variation in non-residential customers results in almost a fifty percent change in the value of reliability.

The main reason for the large divergence in values is easily understood. Generally, business customers incur far higher expenses than residential customers when power is interrupted. Business customers may have to purchase backup generation, relocate their operations, or stop their economic activity altogether, which results in significant costs. When a residential customer loses power, it is likely the customer will wait for the outage to end, rather than purchase expensive backup power equipment. Table 2 supports this conclusion, which shows zero to low cost for at least fifty percent of residential

[48] Sullivan, Michael, Myles T. Collins, Josh Schellenberg, Peter H. Larsen, Michael Hanemann, Granger Morgan, Alex Davis, Sunhee Baik, Parth Vishnav. *Elicitation of Electric Utility Customer Power Interruption Costs: A Roadmap for Conducting a National Survey*. Lawrence Berkley National Laboratory, (December 2019). At 1. (hereinafter "LBNL ICE Calculator Methodology Report"). Available at: https://ice-calc-docs.s3.us-west-2.amazonaws.com/documents/National-Study-Roadmap.pdf

[49] Note: All reported values are in 2025 dollars.

customers. Only in the 95th percentile do costs begin to rise to the level of non-residential customers. The LBNL ICE Calculator Methodology Report lists the following costs that residential customers could incur from outages:

- Value of perishable food stored in refrigerator(s) and freezer(s)
- Damages that result from failure to supply power to other household functions that require continuous power (e.g., fish tanks, food dryers)
- Cost to relocate some or all family members during the outage (when the conditions require it)
- Cost of meals outside the home (when conditions require it)
- Cost to run backup generation if they have it (if they don't have backup generation they should be told to assume it will not be available in nearby stores)
- Cost of transportation to alternate location (if necessary)
- Cost to hire private security (if they choose to do so)[50]

Table 2: Summary of ICE Calculator Interruption Cost Distribution for Residential Customers

Region	Mean	Standard Deviation	Percentiles				
			5%	25%	50%	75%	95%
Northwest	$3.30	$6.60	$0	$0	$0	$3	$18.69
Southeast	$8.80	$13.19	$0	$0	$3.30	$11.00	$29.69
West	$6.60	$19.79	$0	$0	$1.10	$6.60	$31.89

Source: LBNL ICE Calculator Methodology Report at 28

Xcel's value of reliability can also be compared to a separate reliability standard, which is used by MISO. MISO uses a value of lost load (VOLL) construct that places a high value for lost load of $10,000 / MWh of unserved energy.[51] Xcel's $3.05 / CMO value and MISO's $10,000 / MWh unserved energy serve the same purpose, which is to induce spending to increase reliability. The two approaches represent separate constructs that are tasked as solving the same problem. If MISO were to assume

[50] LBNL ICE Calculator Methodology Report – at 23.
[51] *Scarcity Pricing White Paper: Value of Lost Load and Operating Reserve Demand Curve*. Midcontinent Independent System Operator, (March 2024). Available at: https://cdn.misoenergy.org/20240418%20MSC%20Item%2004d%20Scarcity%20Pricing%20White%20Paper%20VOLL%20and%20ORDC632355.pdf (hereinafter "MISO VOLL Report").

equal load shed, instead of primarily residential, with its 48 percent residential customer share, MISO could justify a 2023 VOLL of $36,888 / MWh,[52] and if this value is adjusted to Xcel's 10.43% non-residential customer share, the VOLL would be $11,464 / MWh in 2025 dollars.[53,54,55] However, based on these high cost assumptions and the reasonable expectation that the majority of load should would be residential, MISO chose a cost cap of $10,000 to keep costs reasonable for ratepayers. MISO states:

> MISO proposes a VOLL of $10,000/MWh to use as a market price cap and for administrative pricing during load-shed events. This [figure] recognizes that load-shedding will be focused on the residential class, which has a 1-hour-outage Summer VOLL of $4,337/MWh, but that other load classes would inevitably be dropped during such an event. As shown above, even adding 15% of non-residential load would result in a VOLL of $13,640/MWh. And if load was shed equally across all load types, a VOLL of $36,888 would be justifiable. MISO deems these values to be excessive, however, given the potential financial implications of extended VOLL-pricing.[56]

Xcel's ICE Calculator values can be converted to $ / MWh unserved energy by using the $ / kWh ($1,000 / MWh) of unserved energy and the $ / CMO values listed in Table 3 of the LBNL ICE 2.0 Report, which are proportional to each other:[57]

[52] MISO VOLL Report – at 33.
[53] See MISO 2023 customer class VOLL data in MISO VOLL Report at 32.
[54] Calculations based on data provided by Xcel in IR 45. See Attachment B – DOC IR 45.
[55] The MISO residential VOLL is $4,337 / MWh in 2023 dollars, which is close to the 2-hour ICE residential VOLL, listed at $4.31 / kWh or $4,310 / MWh, however MISO's small commercial and industrial VOLL is $66,354 / MWh, compared to the ICE VOLL of $101 / kWh or $101,000 / MWh for a 2-hour outage. Note that MISO assumes 1-hour outages in its VOLL calculations, while Xcel assumes 2-hour outages, which Table 3 show are less expensive. See MISO VOLL Report at 32.
[56] MISO VOLL Report – at 33.
[57] Larsen, Peter H., Kyle Carney, Joseph H. Eto, George Jiang, Dhawal Joshi, Kristina H. LaCommare, Ridge Peterson, Chris Ramee, Anna-Elise Smith. *ICE Calculator 2.0: Final Report for Phase 1 of National Initiative to Update the Interruption Cost Estimate (ICE) Calculator*. Lawrence Berkley National Laboratory, (May 2025). At xiii. Available at: https://ice-calc-docs.s3.us-west-2.amazonaws.com/documents/ICE+2.0+Phase+I+Final+Report+29May2025.pdf (hereinafter "LBNL ICE 2.0 Report")

Table 3: ICE Calculator Valuation of Unserved Energy and Customer Minutes Out/Interruption (CMI)

Duration of Power Interruption Event	Cost per Event	Cost per kW	Cost per Unserved kWh	Cost per CMI[4]
Residential				
Momentary	$1.80	$1.50	$18.03	$0.36
2 Hours	$10.49	$8.62	$4.31	$0.09
8 Hours	$25.55	$21.21	$2.65	$0.05
24 Hours	$54.52	$44.76	$1.86	$0.04
Non-residential				
Momentary	$609	$43	$521	$122
2 Hours	$2,839	$202	$101	$24
8 Hours	$6,172	$440	$55	$13
24 Hours	$12,646	$902	$38	$9

Source: LBNL ICE 2.0 Report[58]

Using Xcel's Minnesota jurisdictional CMO values for residential and non-residential customers from IR 45 yields a 2025 unserved energy cost of $16,820 / MWh of unserved energy. These results are 46.7% higher than the $11,464 / MWh value the Department calculated based on the MISO VOLL valuation for the Xcel Minnesota jurisdiction, as well as 68.2% higher than MISO's $10,000 / MWh cost cap. If Xcel's ICE-derived $ / CMO estimate is adjusted to the MISO VOLL, Xcel's reliability benefit would decrease to $1.96 / CMO.[59]

The Department requests Xcel explain in reply comments why it is reasonable to assume reliability benefits that are higher than the MISO value of lost load.

While no one wants power outages, no one wants their power bills to go up either. The benefits of reliability must be weighed against the costs to obtain that reliability. There may be circumstances in which the increased risk of outages is preferrable to significant capital expenditures to abate them. In the context of distribution planning, the outages being discussed are local and frequent. In 2023 and 2024, Xcel experienced**[TRADE SECRET DATA HAS BEEN EXCISED]** outages, respectively, which is equivalent to **[TRADE SECRET DATA HAS BEEN EXCISED]**outages per day, respectively.[60] These events

[58] LBNL ICE 2.0 Report – at xiii.
[59] This figure escalates the $10,000 / MWh VOLL that is based on 2023 data to 2025 costs based on Xcel escalators in IR 45.
[60] Attachment B – DOC IR 31, Attachment A. Note that Attachment A is not included in these comments, but can be provided upon request.

are not rare, and instead represent daily occurrences. In contrast, MISO experienced no loss of load events in 2023 and 2024. Compared to MISO-level loss of load events, local outages can be managed with fewer consequences to society. If a feeder loses power, adjacent feeders still have power and can still provide service. As Figure 14 demonstrates, societal costs of utility spending and power outages must be optimized together. Clearly, there is a contrast between the importance of outages at the MISO-level and at the local level, and outages will always be a reality in the distribution system. Yet, Xcel assumes a reliability value for distribution that is higher than what MISO is willing to pay for lost load. It is therefore important that there be a discussion on the appropriate number and cost of outages, which optimizes societal costs.

Table 2 also shows that the standard deviations for ICE Calculator estimates are approximately double the mean values, which means that there is considerable variation in results, and that results in the top 25 percent of values heavily influencing the mean values. Results for Small Commercial and Industrial Customers follow a similar trend to residential.[61] Based on these results, customers who have a greater ability to pay for outage interruptions will be the primary beneficiaries of monetary reliability benefits. In addition to a small number of customers that receive the monetary benefits of reliability, the ICE Calculator uses multiple methodologies to derive the value of interrupted power. Most notably, the ICE Calculator uses both willingness-to-pay and direct-costs surveys, among other methodologies employed.[62] Each of these methods—and any effort to measure the costs of outages—is prone to both error and uncertainty from multiple sources, including sampling, response rates, and the proper elicitation of actual costs. In addition, the calculation of reliability benefits is also prone to significant uncertainty, which determines the CMO savings that are then monetized. The Department does not imply that the ICE Calculator methodology is flawed and recognizes the rigor of analysis provided by LBNL. However, the Department highlights these examples of both variability in results and uncertainty in methodology to advocate for caution when interpreting the results of reliability benefits. The costs of reliability mitigations are basically certain, but the reliability benefits are not. Given that reliability mitigations such as underground compared to overhead lines can cost almost double,[63] there is reason to require enhanced certainty of benefit accrual for reliability projects. If rates are to increase for reliability projects, there should be a clear reliability benefit of these projects. For example, MISO has a minimum benefit cost ratio (BCR) requirement of 1.25 for its Market Efficiency Projects (MEP).[64] The Department thinks that a similar minimum BCR requirement is warranted for projects that are primarily justified by reliability benefits, to ensure that ratepayers receive clear reliability benefits. When assessing the reliability benefits of programs or projects, the Department will determine the reasonableness of distribution reliability projects if they demonstrate a minimum cost benefit ratio of 1.25 to 1.

[61] See Table 3-3. LBNL ICE Calculator Methodology Report – at 47.
[62] LBNL ICE Calculator Methodology Report.
[63] Attachment B – DOC IR 96.
[64] *MTEP25 Transmission Portfolio*. Midcontinent Independent System Operator, (2025). At 11. Available at: https://cdn.misoenergy.org/MTEP25%20Chapter%201%20-%20Transmission%20Planning%20Overview720401.pdf?v=20250929111625

F. FORECASTING RESULTS AND METHODOLOGY

The Department responds to the following notice topic:

> *Notice Topic 16.B: Feedback, Comments, and Recommendations on the forecasting results and methodology*

Xcel's forecasts show rapid load growth on Xcel's system. These forecasts trigger capacity upgrades, which then result in higher budget requests. The Department analyzes Xcel's forecast to ensure that its forecasts are reasonable. Forecasts that are too high raise important affordability issues if the forecasts turn out to be inaccurate, and capacity spending is not necessary for years after the forecasted capacity need.

F.1. System-Wide Forecast

The Department analyzed Xcel's system-wide forecast and its LoadSEER forecast in the Department's January 28, 2026 Initial Comment on Xcel's Proactive Upgrade Proposal.[65] The Department does not re-analyze Xcel's forecast in these comments, but provides a summary of the Department's analysis. Table 4 provides an analysis of Xcel's system-wide forecast accuracy, which is used as an input to LoadSEER's feeder and substation capacity forecasts. Average near-term forecast accuracy, which is used in Xcel's standard capacity planning process for years 1 through 5, has generally been good, with a year 1, 2, 3, 4, and 5 average deviation from actual forecasted energy sales of -0.2%, 0.3%, 1.0%, and 1.6%, respectively. These data indicate that forecast years 1 through 5 are generally accurate as an input to local substation and feeder forecasts used by LoadSEER.

Table 4: Analysis of Xcel System-Wide Forecast Accuracy of Energy Sales

	Forecast Vintage									
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
2015	1.4%									
2016	2.1%	1.2%								
2017	3.9%	3.1%	1.5%							
2018	1.5%	0.3%	-1.4%	-3.1%						
2019	6.2%	5.2%	3.6%	0.0%	0.6%					
2020	10.3%	9.5%	7.4%	3.6%	4.4%	1.6%				
2021	7.5%	6.8%	4.8%	0.5%	1.1%	-2.1%	-3.1%			
2022	7.4%	6.5%	4.1%	-0.2%	0.4%	-3.1%	-3.7%	-2.3%		
2023	8.6%	7.6%	5.1%	0.4%	0.9%	-3.0%	-3.8%	-1.5%	-1.2%	
2024	12.6%	11.5%	8.7%	3.8%	4.4%	-0.3%	-1.0%	2.1%	1.5%	1.9%

Source: Docket No. E999/M-YR-11

[65] Department Initial Comments on Xcel's Proactive Upgrade Proposal – at 5-6.

As the Department explains in its Initial Comments on Xcel's Proactive Upgrade Proposal, Xcel's LoadSEER forecasts appear systematically biased to estimate too much capacity need compared to actuals; however, the data remains preliminary at this time.[66] Based on Xcel Table 1-11, the 2023 IDP Low forecast was 6.1% higher than the actual in 2023 and 10.1% higher than the actual in 2024, which is not observed in the Xcel system-wide forecast data.[67]

If confirmed, these results suggest that Xcel needs to recalibrate its LoadSEER model to better match actual peak loads. If left unchecked, Xcel could end up making capacity upgrades that may not be needed until years after the install date. Xcel should continue to analyze its forecast accuracy in every IDP to ensure that its forecasts do not induce unnecessary capacity projects.

The Department repeats its forecast accuracy recommendation from its Initial Comments on Xcel's Proactive Upgrade Proposal, should the Commission prefer to take up the issue here rather than in Xcel's Proactive Upgrade Proposal.[68] Xcel's forecast accuracy should include each of its IDP Low, Medium, and High forecasts, which Xcel describes in its 2023 IDP as follows:

> To align with the intent of IDP Requirement 3.C.1, the "IDP Low" scenario represents what is considered the base case, or expected adoption forecast for each DER technology forecasted. The "IDP Med" and "IDP High" scenarios then represent faster-than-expected adoption scenarios for each DER technology, adding an extra 10 percent and an extra 25 percent of DER adoption over the base case, respectively.[69]

The Department notes that the 2023 vintage scenarios are different from the 2025 vintage scenarios, and therefore Xcel should provide an analysis of each forecast vintage.

The Department recommends the Commission create a new IDP filing requirement to provide a comparison of forecast accuracy for each vintage and scenario (IDP Low, Medium, High) in Xcel's LoadSEER forecasts compared to actuals.

F.2. Planning Division Forecasts

The Department examines the geographic units and their respective forecasts used by Xcel for distribution planning. The IDP relies heavily on "Planning Divisions" (PDs) as the primary unit for forecasting load, identifying constraints, and allocating capital spending. As such, the definition, scope, and consistency of these planning divisions are foundational to the formation of IDP budgets.

[66] *Id*., – at 6-7.
[67] 2025 IDP - Chapter 1 at 77.
[68] See Notice Topics 7-10. Notice at 1.
[69] 2023 IDP - Attachment A1 at 50.

F.2.1. Definition and Scope of Planning Divisions

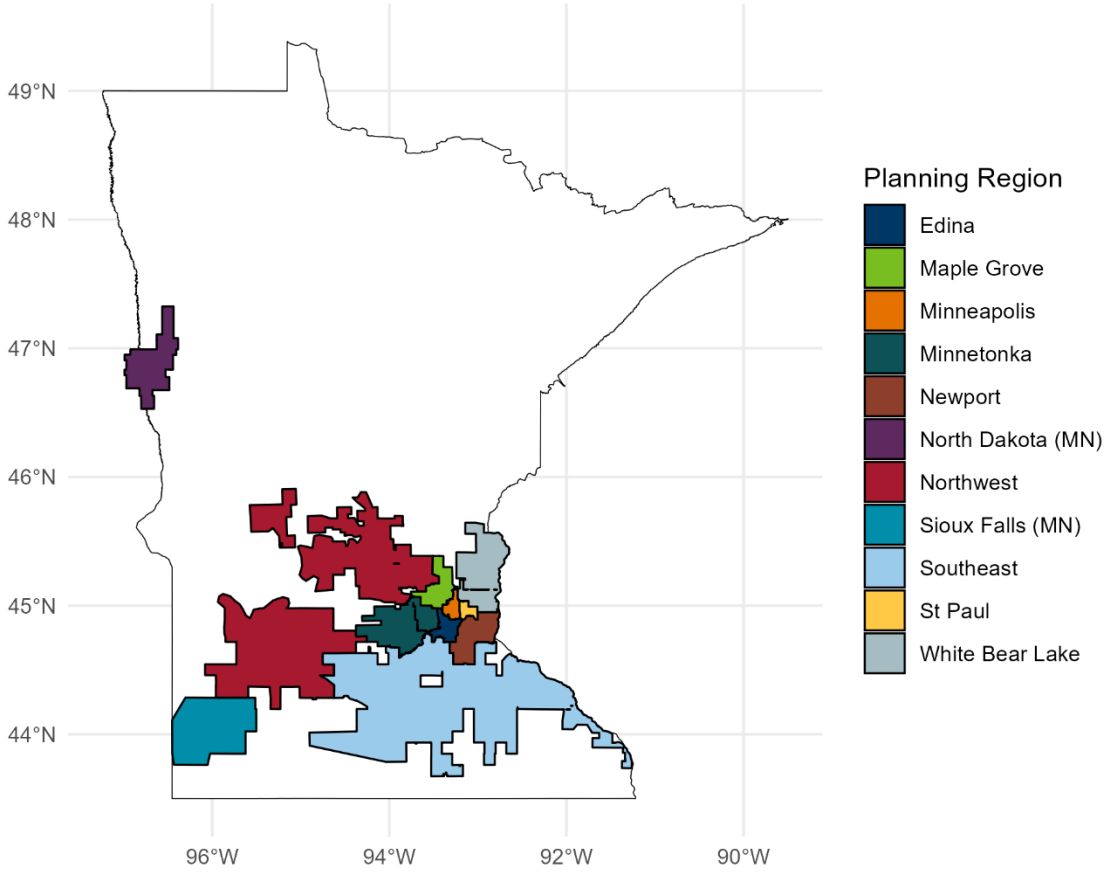
Xcel describes its PDs as follows:

> The Company's Minnesota service territory is divided into 11 planning divisions. These divisions are primarily based on the customers served by a subset of electric assets and generally align with service center territories, though some overlap occurs when assets (e.g. feeders) cross service center boundaries. In certain cases, multiple service centers are grouped together into one planning division for efficiency.
>
> Each planning division is assigned a unique location code, which is used to track and record some of the distribution system spending for that area. For projects, programs, and blankets that span multiple divisions, a separate location code is applied.[70]

Figure 15 shows these planning divisions based on the maps provided by the Company.

[70] Attachment B – DOC IR 4.

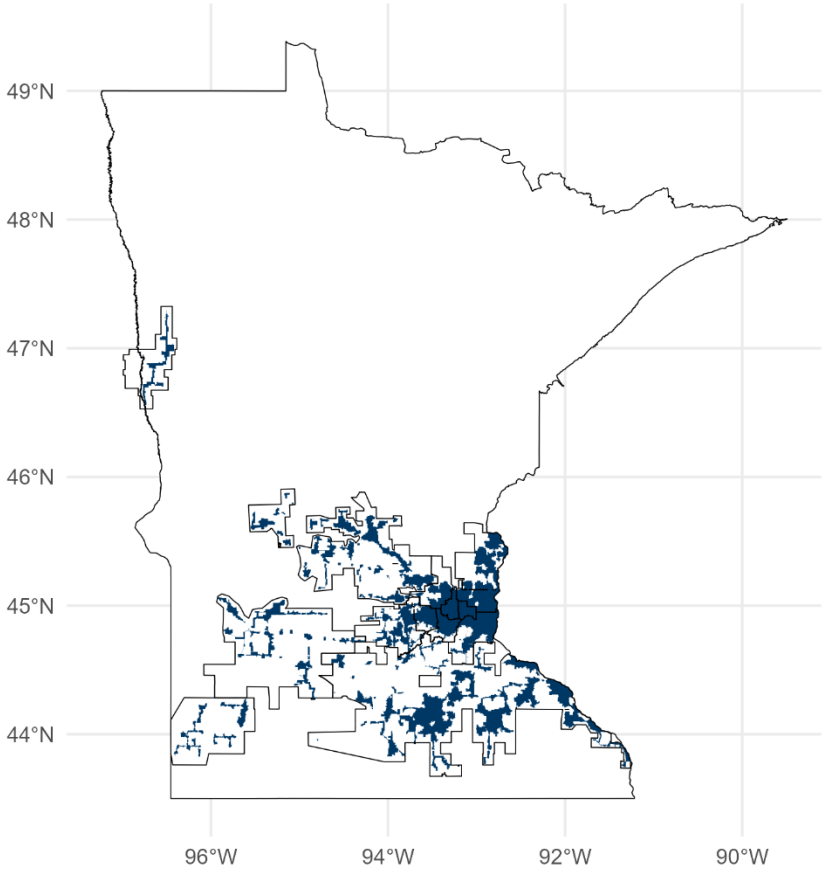
Figure 15: Map of Xcel's Planning Divisions



Source: IR 7

Figure 16 overlays the service territory with the PDs to provide a clear contrast of the difference between Xcel's planning divisions and its service area.

Figure 16: Overlap of Xcel's Service Territory and the PDs



Source: IR 7

The comparison shows that while Xcel's service territory spans approximately 4,400 square miles in Minnesota, their PDs cover approximately 17,000 square miles.

The Department requests that Xcel explain in reply comments:

- **A. Why Planning Divisions encompass areas well beyond the Company's Minnesota service territory;**
- **B. Whether load, asset, or spending data from outside Xcel's service territory are embedded in PD-level forecasts used in the IDP; and**
- **C. How the Company ensures that Minnesota-specific planning and regulatory decisions are not influenced by non-jurisdictional conditions.**

Without this clarification, it is difficult to determine whether PD-level investment needs and forecasts accurately reflect Xcel's Minnesota customers and assets.

F.2.2. Volatility in Peak Load Forecasts by Planning Division

Utilities often use projected peak demand to justify infrastructure investments. To assess the reliability of Xcel's peak load forecasts, the Department calculated year-over-year percentage changes in peak load by Planning Division using data from IR 11.[71] Table 5, which compares actual percentage changes in peak load (2020–2024) to projected values (2026–2029), summarizes these results.

The data show significant volatility in historical peak load changes across PDs, including large swings that are difficult to reconcile with the projections in future years. Additionally, most PDs show sharp declines in 2024 followed by large projected increases in 2026.

Table 5: Change in Peak Load Compared to the Prior Year by Planning Division

(Historicals 2020-2024; Forecast 2026-2029)

	2020	2021	2022	2023	2024	2026	2027	2028	2029
Planning Area									
Edina	-2.30%	4.78%	1.13%	4.13%	-5.26%	10.24%	0.26%	0.50%	0.37%
Maple Grove	-5.08%	5.65%	-1.05%	4.37%	-5.23%	22.04%	0.46%	0.66%	0.50%
Minneapolis	-12.08%	10.14%	0.69%	2.34%	-2.55%	8.89%	0.55%	0.58%	0.59%
Minnetonka	-28.65%	17.17%	-6.18%	19.38%	-6.62%	6.91%	0.45%	0.60%	0.50%
Newport	-60.61%	22.44%	116.39%	3.69%	-0.85%	0.86%	0.60%	0.73%	0.56%
Northwest	-90.30%	37.15%	833.71%	-3.74%	-2.39%	2.07%	1.37%	0.69%	0.56%
Sioux Falls/ South Dakota	-60.23%	8.22%	-2.74%	131.94%	7.47%	0.83%	0.42%	0.70%	0.70%
Southeast				12.71%	-0.96%	1.71%	0.30%	0.47%	0.33%
St Paul	-78.25%	31.27%	221.36%	5.81%	1.32%	8.61%	0.42%	0.45%	0.46%
White Bear Lake	-6.17%	6.00%	-0.08%	5.00%	-1.89%	8.54%	0.91%	1.16%	1.01%
Total Minnesota	-38.47%	10.17%	47.35%	4.86%	-2.54%	7.59%	0.59%	0.64%	0.55%

The Department requests that Xcel explain in reply comments the highlighted values in Table 5 and reconcile these projections with historical patterns.

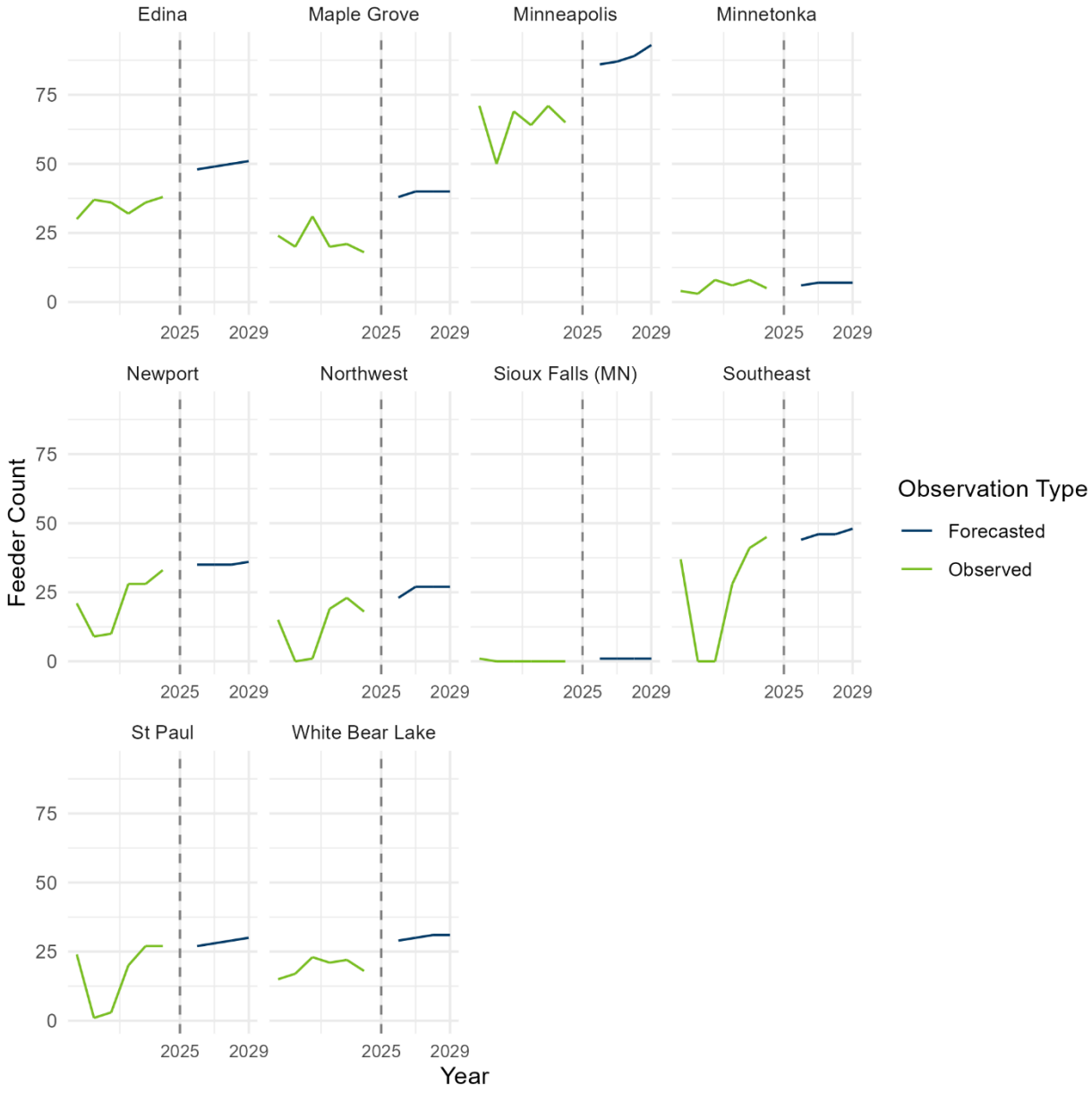
F.2.3. Feeder Capacity by Planning Division

Xcel identifies the need to upgrade feeder capacity as a major driver of distribution spending. To better understand this driver, the Department requested data on feeder utilization. In response to IR 8, Xcel provides counts of feeders operating above 50 percent and 75 percent of their planning limits. Figure 17 summarizes the number of feeders exceeding 75 percent of planning capacity over time,

[71] Attachment B – DOC IR 11, Attachment A. Note that Attachment A is not included in these comments, but can be provided upon request.

disaggregated by Planning Division. This figure indicates that capacity constraints are not evenly distributed across the system; certain PDs consistently exhibit higher numbers of heavily loaded feeders.

Figure 17: Number of Feeders That Exceed the 75% Capacity Planning Standard: 2019–2029



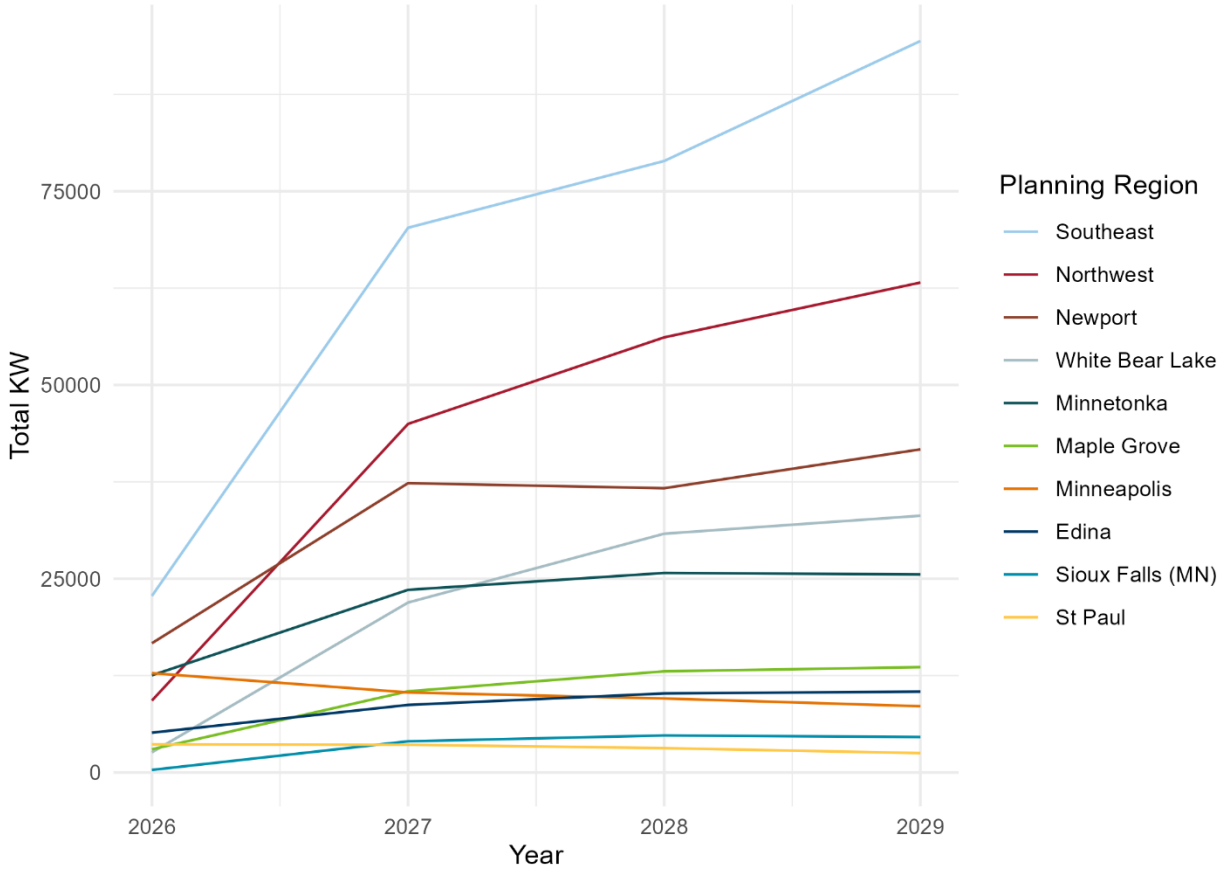
These patterns raise important questions about the underlying causes of forecasted rise in feeder congestion and whether capital investments are efficient. While most planning divisions show observable trends in Figure 17, Edina, Maple Grove, Minneapolis, and White Bear Lake all show visible

jumps in the number of feeders expected to be overloaded when the data transitions from actuals to forecasts.

F.2.4. Load Forecast Drivers and Electrification Assumptions

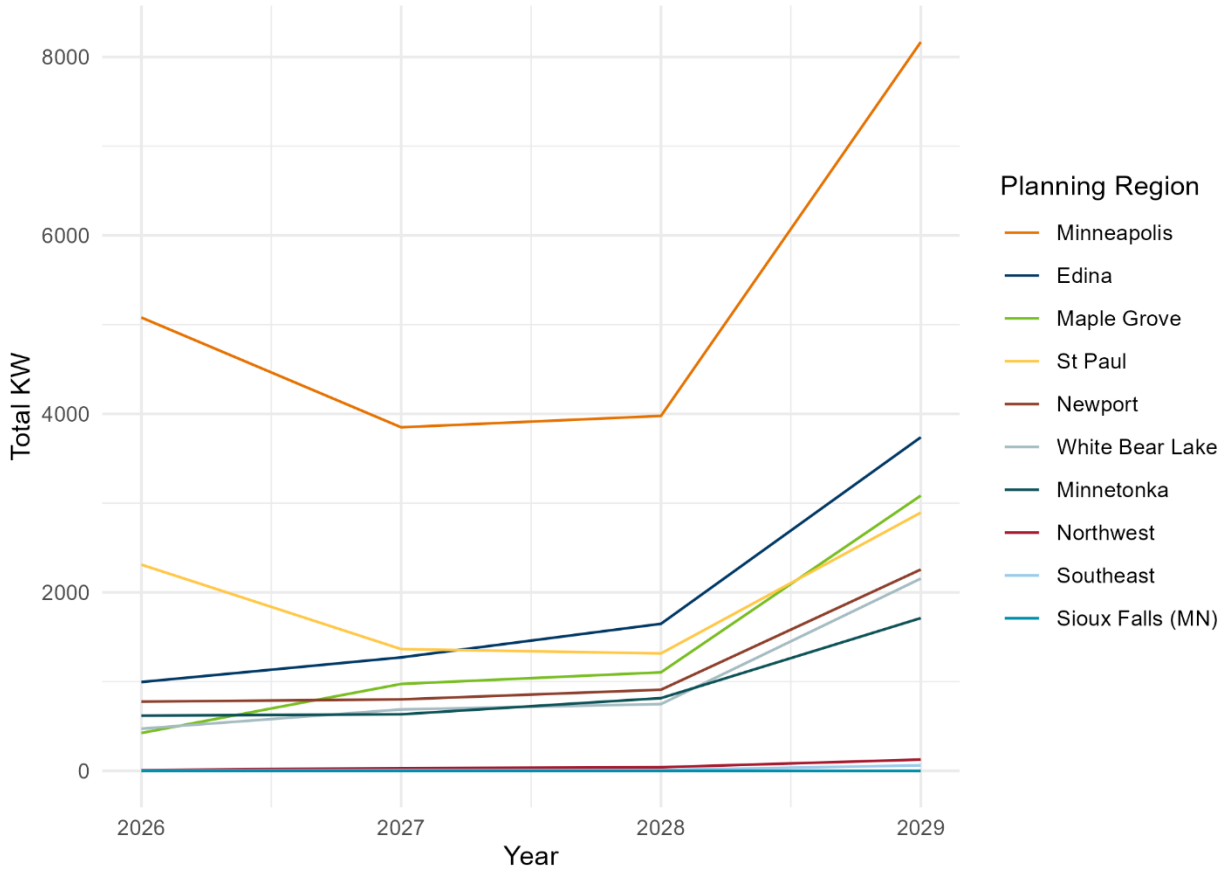
The Department examines Xcel's Planning Division–level load forecasts to better understand the drivers of projected peak demand growth and the extent to which electrification assumptions influence capacity planning decisions. As shown in Figure 18, certain Planning Divisions—notably the Southeast and Northwest PDs—exhibit particularly large increases in forecasted peak PV load over a relatively short time horizon. These increases warrant closer scrutiny given their implications for feeder upgrades, substation expansions, and other capital-intensive distribution investments.

Figure 18: Projected Increase in PV Load by Planning Division



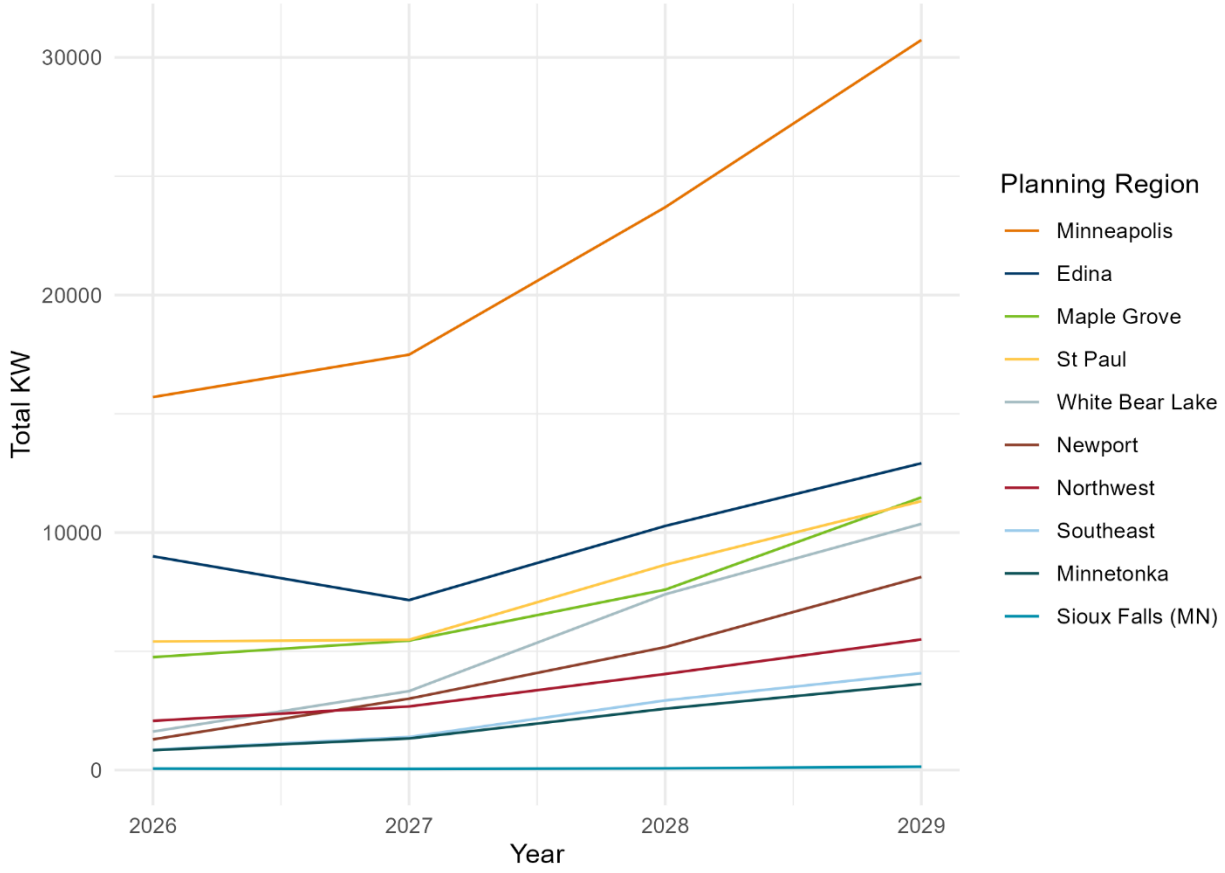
To better understand these projected increases, the Department reviewed the individual components contributing to peak load growth, as provided by the Company in response to IR 11 and summarized in Figures 19–21. This breakdown indicates that electrification-related loads—particularly electric space heating and electric vehicle (EV) charging—are major contributors to projected peak demand in several Planning Divisions.

Figure 19: Projected Increase in Heating Load by Planning Division



For example, in Minneapolis, forecasted heating-related peak load is projected to approximately double within a two-year period. Similarly, EV-related peak load increases sharply in multiple PDs over the forecast horizon. While electrification is an expected long-term trend, the magnitude and timing of these increases raise questions about the underlying assumptions driving the Company's forecasts.

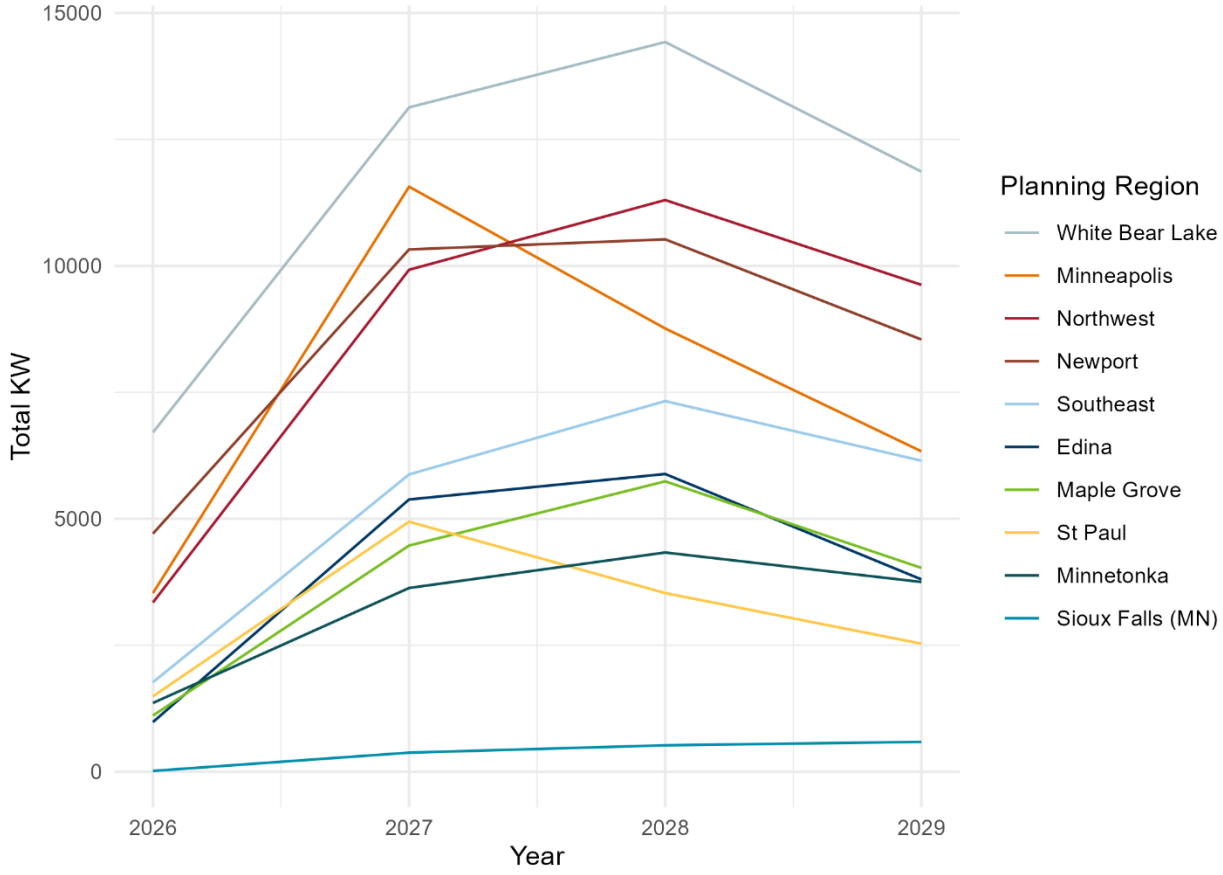
Figure 20: Projected Increase in EV Load by Planning Division



In particular, the Department is concerned that projected peak load growth may be driven by optimistic assumptions regarding the pace of technology adoption rather than by empirically observed trends. Recent historical data on heat pump installations, EV adoption, and customer load shapes generally show more gradual uptake, influenced by factors such as equipment costs, building stock turnover, consumer preferences, and infrastructure constraints.[72] The Company's forecasts appear to assume rapid and widespread adoption over a short period without clearly demonstrating that such adoption rates are consistent with observed customer behavior in each Planning Division.

[72] Historical trends in American Community Survey and Minnesota Department of Transportation do not comport with the data Xcel presents. Walker, Kyle, Matt Herman. *tidycensus: Load US Census Boundary and Attribute Data as 'tidyverse' and 'sf'-Ready Data Frames*. R package version 1.7.5, (2026). Available at: https://walker-data.com/tidycensus/authors.html; *Performance Measure Dashboard*. Minnesota Department of Transportation (2026). Available at: https://www.dot.state.mn.us/measures/electric-vehicles.html

Figure 21: Projected Changes in New Commercial and Residential Load by Planning Division



As described in the Department Initial Comments on Xcel's Proactive Upgrade Proposal:

> Xcel's LoadSEER forecast does not account for the recission of the Inflation Reduction Act (IRA) tax credits. Xcel confirms that the LoadSEER forecast includes the full IRA tax credits in IR 25.
>
> […]
>
> On net, the Department expects that reduced EV and electrification adoption will reduce peak load forecasts more than reduced energy efficiency will increase peak load forecasts.[73] [citation omitted]

The Department is concerned that the Company's electrification forecasts may not adequately account for load diversity and temporal effects. For example, assumptions regarding coincident EV charging during system peak hours or simultaneous operation of electric heating across large customer segments can substantially inflate projected peak demand if not grounded in empirical usage data.

[73] Department Initial Comments on Xcel's Proactive Upgrade Proposal – at 8-9.

Similarly, assumptions about heat pump performance during extreme cold events, backup resistance heating usage, and customer response to price signals or demand management programs materially affect peak load outcomes.

Taken together, these issues call into question whether the forecasted increases in peak load—particularly the sharp increases projected in certain Planning Divisions—are sufficiently supported by data. Given that peak demand forecasts directly drive capacity-related investments, overly aggressive electrification assumptions risk leading to premature or excess infrastructure spending, with associated cost impacts on ratepayers.

The Department therefore requests that Xcel provide additional detail in reply comments regarding the drivers of projected peak load growth, including:

- **A. The specific adoption rates for EVs and electric heating technologies assumed in each Planning Division;**
- **B. The empirical data sources used to justify these adoption rates;**
- **C. Explicit assumptions regarding the availability and level of subsidies and incentives over the forecast period;**
- **D. Sensitivity analyses showing how peak load forecasts change under alternative adoption and policy scenarios; and**
- **E. An explanation of how load diversity, customer behavior, and demand management are reflected in peak load estimates.**

Without this information, the Department has concerns about the reliability of Xcel's Planning Division–level peak load forecasts and the need for capacity investments justified on the basis of these projections.

G. CAPACITY

The Department responds to the following notice topic:

> *Notice Topic 17: Other Areas of Xcel's IDP Not Listed Above, Along with Any Other Issues or Concerns Related to This Matter.*

Xcel plans to spend $1.21 billion in 2025 dollars on capacity projects between 2025 and 2030, which compares to $240 million in 2025 dollars on capacity projects between 2019 and 2024.[74] This planned spending reflects a five-fold increase in Xcel's capacity budget. While the Department understands that the primary driver for Xcel's budget increase is forecasted increases in peak load, the increase in Xcel's budget is alarming. The sharp increase in capacity spending raises important affordability issues that require careful oversight.

[74] See Figure 2.

G.1. Summary of Xcel's Capacity Planning Standards

Xcel's capacity planning standards are summarized in Table 6:

Table 6: Summary of Xcel's Capacity Planning Standards

Table 1 - 12
Risk Thresholds Requiring Mitigations

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

Source: 2025 IDP – Chapter 1 at 83

Xcel does not explain the justification for its 75% and 50% feeder N-0 thresholds in Chapter 1, where Xcel presents the standards. However, Xcel provides a description of the N-0 Threshold in its NWA section. The Company states:

> In our 2023 NWA analysis, a new metric titled the forecast uncertainty margin was added to the NWA initial screen. This margin reflects the fact that forecasts are inherently uncertain and cannot be perfectly accurate. It also aligns with our planning standards, which target feeder loading at 75 percent of capacity or less and targets substation transformer loading below 100 percent of capacity. Since NWA solutions are sized based on forecasted peaks, accounting for inaccuracies in potential load growth is critical.
>
> Forecasts can have relatively high accuracy when observed at the system-wide level, but at the granularity of an individual feeder circuit or substation discrete changes, such as one large customer connecting to the grid, can introduce significant variance in the forecast. Even if load growth was anticipated in an area and included in the forecast, if the actual customers that ultimately interconnect in the area happen to have a higher or lower load density than was assumed then the forecast will not have been accurate. If an NWA is sized to precisely meet the need identified in the forecast, then such a forecast variance could cause the NWA to no longer be able to meet the need that actually develops based on how the NWA technology was sized. Therefore, NWAs need to be sized accordingly to account for uncertainty in the forecast.

> In the N-0 risk case, the forecast uncertainty margin reflects 75 percent of the feeder limit, which aligns with our planning criteria. In the N-1 risk case, we scale the peak of the N-1 overload load curve up by 25 percent and assess the overload against 100 percent of the feeder limit, which also aligns with our planning criteria. For both cases, the need shape is developed using the forecast uncertainty margin, resulting in a larger need shape, which is important to ensure the NWA is sized appropriately to be able to maintain reliability under futures with higher loads.[75]

Xcel provides a description of its N-1 Threshold as follows:

> Distribution Planning delivers an N-1 Contingency Analysis, which is a list of all feeders and substation transformers for which the loss of that feeder or transformer results in an overload on an adjacent feeder or transformer, or loss of service for customers. For example, a 1.5 MVA N-1 condition for feeder FDR001 means that for loss of FDR001, all but 1.5 MVA of FDR001's peak load can be safely transferred to adjacent feeders without causing an overload. The remaining 1.5 MVA that cannot be transferred is then referred to as "load at risk." This risk reflects the ability of the system to be reconfigured to serve all the load. Any N-1 risk means that the N-1 analysis determined that there was not sufficient redundancy to supply the electricity demand once a given element has been lost. The Customers subjected to this N-1 outage would be without power until repairs are made, and the system is restored to an N-0 state.[76]

Xcel's 75% N-0 standard also serves as buffer capacity for Xcel's N-1 standard. In the event of an N-1 contingency, the 75% standard allows Xcel to transfer the full faulted feeder's remaining load to adjacent feeders during a peak load event. Therefore, the N-0 and N-1 standards are closely related to each other.

G.1. N-0 Forecast Uncertainty Analysis

Xcel's 75 percent forecast uncertainty margin is a 33.3 percent forecast deviation margin, relative to the forecasted load. In addition, this error margin is one-tailed, such that only forested load that is lower than actual load is a problem with regard to overloads. The Department analyzes data from IR 74 to test the validity of Xcel's 33.3 percent forecast uncertainty margin. This IR provides forecast accuracy data for all projects over $5 million in Xcel's capacity project list in the 2025 IDP Attachment E, and contains for 30 projects.[77]

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[75] 2025 IDP – Chapter 8 at 42.
[76] 2025 IDP – Chapter 1 at 82-83.
[77] Attachment B – DOC IR 74. Note that Attachment A is not included in these comments, but can be provided upon request.

[TRADE SECRET DATA HAS BEEN EXCISED] …. Figures 22 and 23 show that there was one project that exceeded Xcel's forecast margin error of 33.3% in forecast year 1, and also one project that exceeded the margin of error in forecast year 2, which is shown in the "≤ - 40.0%" bin. In both cases, the greatest deviation observed is in excess of 50% higher than the forecasted value. The single overload corresponds to 4.5% of feeders in the dataset, however the dataset is relatively small.

Figure 22: Forecast Accuracy for Projects Over $5 Million in Forecast Year 1

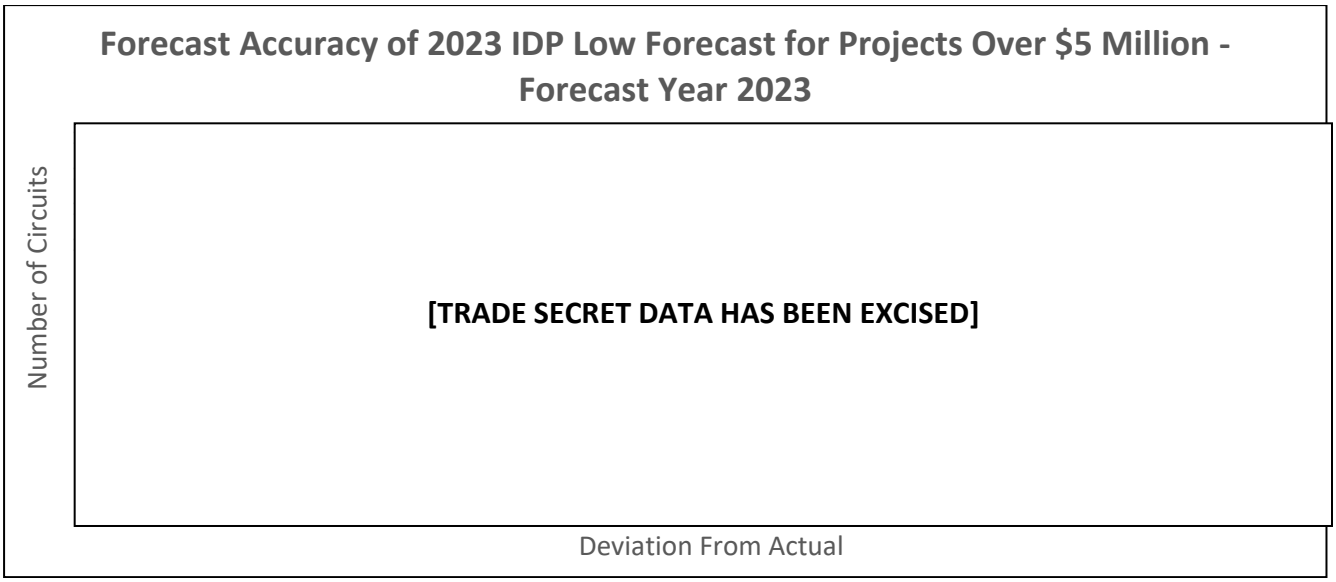
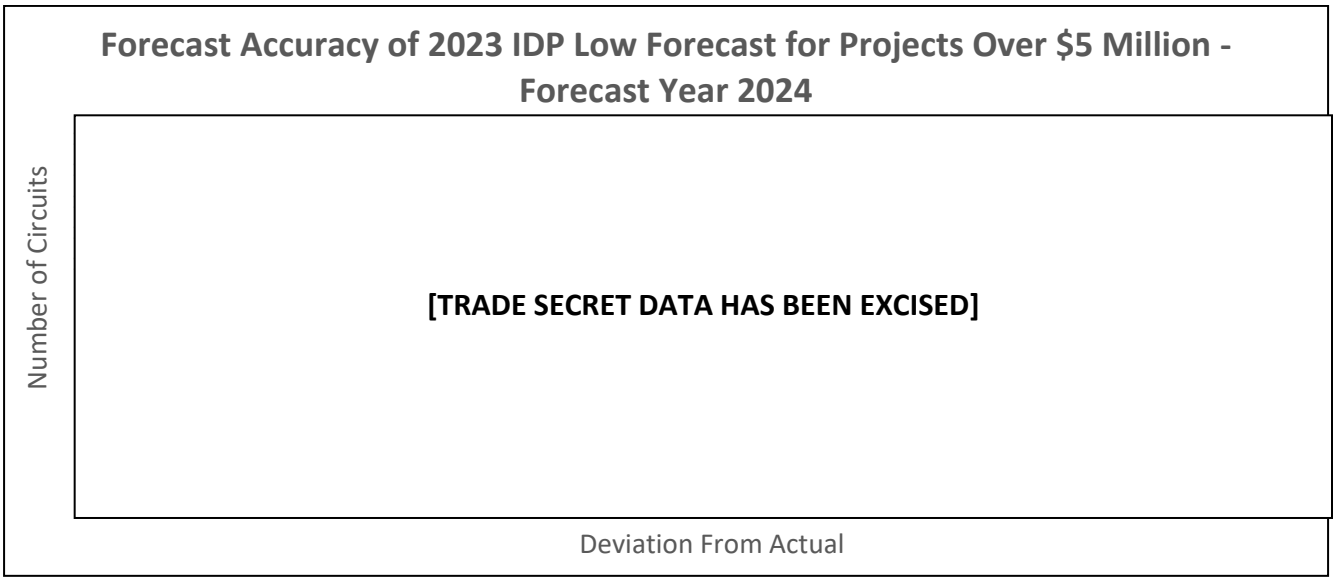
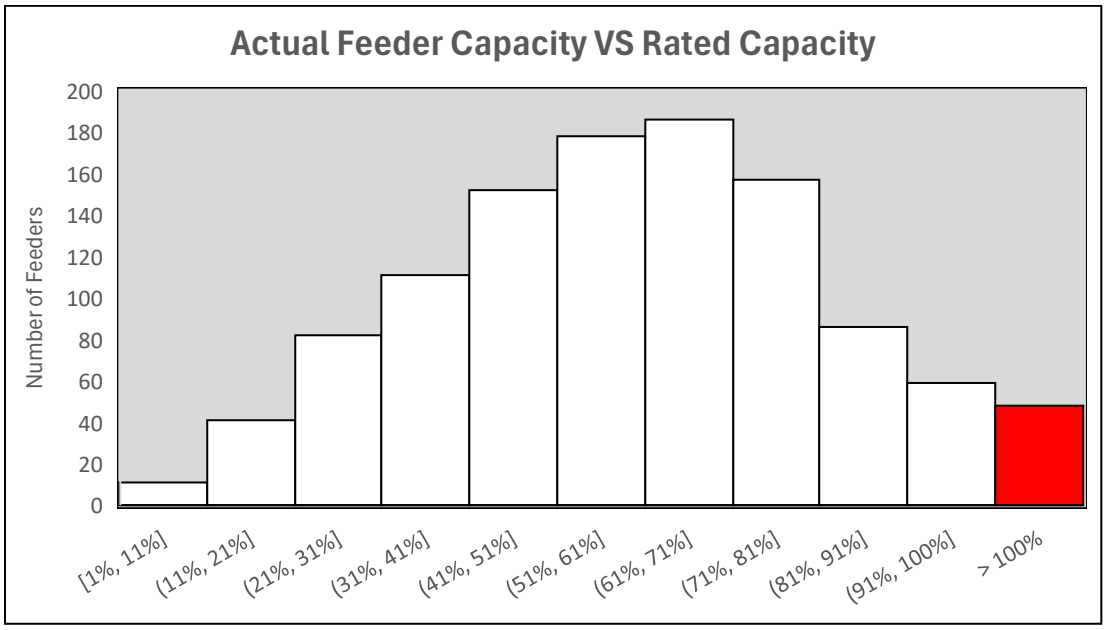


Figure 23: Forecast Accuracy for Projects Over $5 Million in Forecast Year 2



Xcel's feeder capacity data reflects a similar pattern, where 3.2% of feeders are currently overloaded, as shown in Figure 24.

Figure 24: Actual Feeder Loading Compared to Rated Capacity



Source: Department IR 34

If Xcel were to relax the 33.3 percent forecast deviation margin to 25 percent, which would allow for 80 percent feeder loading before an upgrade is triggered, then the number of overloaded feeders would rise to 7.5 percent, which is a 4.3 percentage point increase, or over double the current number of overloaded feeders. Conversely, if Xcel were to increase 33.3 percent forecast deviation margin to 42.9%, which would correspond to a 70 percent feeder loading before an upgrade is triggered, then the number of overloaded feeders would decrease to 2.9 percent, which is a 0.3 percentage point decrease, or approximately ten percent.

Xcel reports **[TRADE SECRET DATA HAS BEEN EXCISED]** outages between 2023 and 2024 that are labeled as **[TRADE SECRET DATA HAS BEEN EXCISED]** in IR 31. These outages resulted in **[TRADE SECRET DATA HAS BEEN EXCISED]** CMOs, with an average of **[TRADE SECRET DATA HAS BEEN EXCISED]** CMOs per outage. Using Xcel's $3.05 / CMO estimate, each outage costs **[TRADE SECRET DATA HAS BEEN EXCISED]**in reliability costs. There are additional costs, such as emergency repair costs, and decreased equipment life that are not factored into this estimate. Regardless, at the level of reliability cost, Xcel's current N-0 standard costs approximately **[TRADE SECRET DATA HAS BEEN EXCISED]** million in overload outages annually. A 70 percent forecast deviation margin would decrease the reliability cost by approximately **[TRADE SECRET DATA HAS BEEN EXCISED]** million annually, and the 80 percent forecast deviation margin would increase the reliability cost by **[TRADE SECRET DATA HAS BEEN EXCISED]** annually.

These costs must be weighed against Xcel's capacity budget. A 70 percent forecast deviation margin would induce earlier capacity upgrades and would increase Xcel's capacity budget. Conversely, an 80 percent forecast deviation margin would decrease Xcel's capacity budget. Xcel's 2025-2030 average annual capacity budget is $202 million in 2025 dollars.[78] Assuming only capitalization over a 30-year window, a one-, two-, three-, four-, and five-year deferral benefit would yield an annual deferral benefit of $7.1, $13.9, $20.2, $26.1, and $31.7 million, respectively.[79] These deferral benefits correspond to a compound annual growth rate of approximately 6.7%, 3.3%, 2.2%, 1.6%, and 1.3%, respectively for feeders at 75% of rated capacity.[80] For comparison, Xcel anticipates a native peak load compound annual growth rate between 2026 and 2036 of approximately 0.83%.[81] These estimates also do not include taxes or the benefit of avoided double payments for undepreciated infrastructure, which could significantly raise the value of a deferral benefit. While the Department does not expect a significant portion of Xcel's capacity budget to be deferrable, even a 50 percent applicability still presents a compelling case to study the N-0 planning standard. In addition, these reliability costs represent higher costs than MISO is willing to pay for lost load.

The Department's discussion thus far focuses on changes to Xcel's planning standard rather than its other processes. Changes in planning standards, coupled with other measures, provide the greatest benefit and increases accuracy. For example, if Xcel were to use its Advanced Metering Infrastructure (AMI) data, coupled with load growth data from its Energy Conservation and Optimization (ECO) and New Customer interconnection data, Xcel could know, rather than guess, how much additional load is added to its system. While LoadSEER forecasts should use AMI data, these forecasts lack the temporal sensitivity to rapidly respond to changes in load conditions. For example, if a new 500 kW load is added to a feeder, AMI data can rapidly indicate that a feeder is at risk for overload, rather than relying on an uncertain forecast. Rapid response to new load additions would allow Xcel to re-prioritize its capacity mitigations to avoid overloads with a high N-0 limit. In addition, new load interconnection programs, such as flexible energization could be used to avoid overloads until permanent upgrades are made. Rapid response would also allow Xcel to deprioritize projects on the oppose end of forecast error, which have lower actual energy use than forecasted. The addition of these data sources into its capacity planning would allow Xcel to mitigate overloads before they happen, without the requirement of a 33.3 percent margin of error. This change to the allowable margin would possibly reduce actual overload outages on Xcel's system. While the Department understands the importance of retaining capacity for new load interconnections, this change would only apply to feeders that are at their capacity limit. The Department asserts that 33.3 percent margin seems high relative to a new load reserve margin.

The Department does not advocate that Xcel change its N-0 forecast deviation margin in these comments, and fully expects Xcel to dispute the Department's claims. The Department is not also

[78] See 2025 IDP – Appendix L.
[79] These estimates assume a weighted average cost of capital (WACC) of 6.345%.
[80] These estimates assume that the planning standard grows from 75% to 80% of rated capacity.
[81] See Figure 1-28. 2025 IDP – Appendix L.

advocating for a cost-effectiveness test for individual N-0 overloads due to the relative certainty of these overloads. Rather, the Department requests that Xcel examine whether its N-0 standard is cost effective.

The Department acknowledges the analysis presented in this section is not sufficient to draw firm conclusions. Any rebuttal, however, does not change the fact that Xcel does not appear to have a current analyzed its N-0 standard for cost effectiveness. In addition, the current standard results in overload outages, and therefore the Department wants to determine how many outages are in the public interest. A sensitivity analysis of the standard does not harm Xcel's system, and allows for a robust debate about what the correct number should be, and how overloads can be prevented with better data. This discussion requires more data and analysis than can be provided in these comments, which is why the Department advocates for additional analysis to take place outside of the IDP comment period.

G.2. N-1 Standard Analysis

Two central assumptions of Xcel's N-1 Standard require careful review. First, Xcel assumes a near-worst-case scenario that all feeders in its N-1 analysis are at 100 percent loading. Xcel states: "In the N-1 risk case, we scale the peak of the N-1 overload load curve up by 25 percent and assess the overload against 100 percent of the feeder limit, which also aligns with our planning criteria."[82] As discussed previously, only 3.2 percent of Xcel's feeders are at or above their rated capacity. 9.4 percent of feeders are loaded at 95 percent, and 13.1 percent of feeders are loaded at 90 percent; approximately 9 out of 10 feeders in Xcel's N-1 analysis will assume grid conditions that are overly conservative and that Xcel will estimate more "load at risk" than actually exists.

The second assumption concerns the probability of an N-1 event with a peak load event. Xcel provides a summary of how its N-1 reliability benefits are calculated in IR 63:

> The avoided CMO benefit for N-1 events is calculated using the following formula: (0.5)(Peak Load MVA – Available Relief MVA)(Customers per MVA)(Peak Day hours out/24)(Hours to restore)(60 minutes)(Failure Rate). This formula applies the failure rate to capture the likelihood of an N-1 event and its impact on outage duration and customer exposure.[83]

This formula accounts for the probability of an N-1 event during a peak load event with a Failure Rate. The Failure Rate appears to be derived from the annual hours at risk:

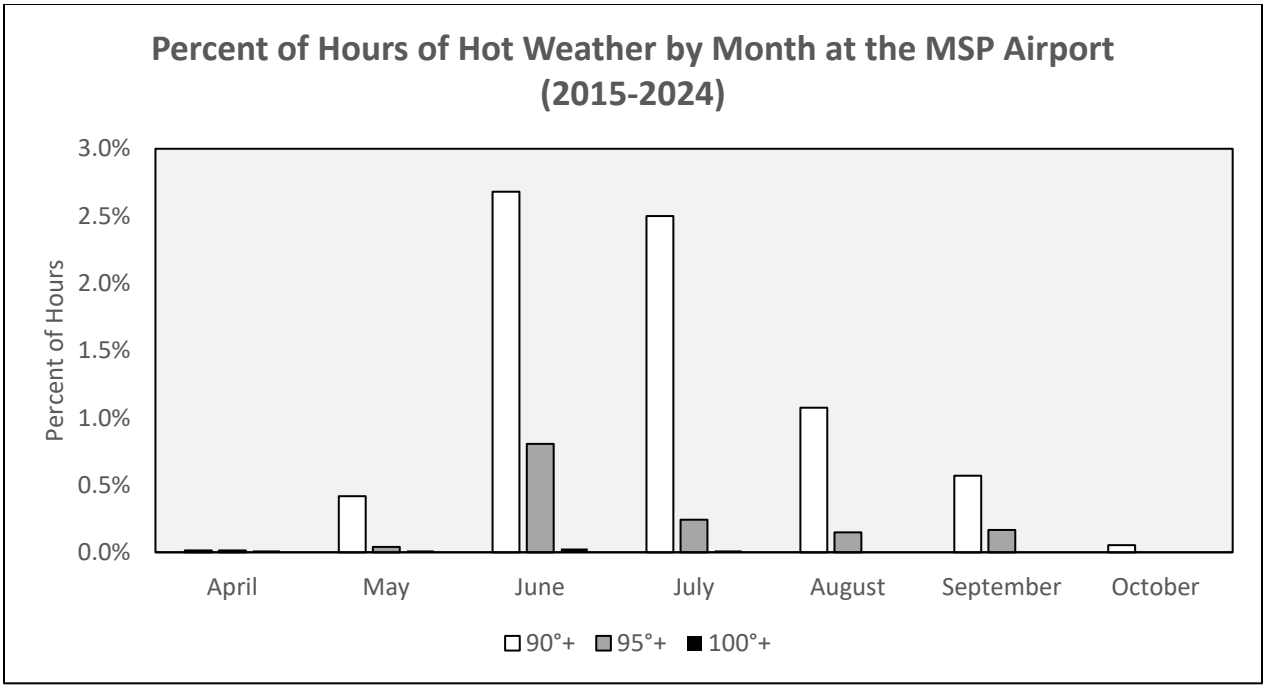
> While the Capacity Risk Scoring methodology does not combine the probability of an N-1 contingency event occurring simultaneously with a peak load event, the annual hours at risk are included within the N-1 calculation based on the estimated load duration curve for the asset.[84]

[82] 2025 IDP – Chapter 8 at 42.
[83] Attachment B – DOC IR 63.
[84] Attachment B – DOC IR 64

[TRADE SECRET DATA HAS BEEN EXCISED].

Additionally, the Department analyzes data on the likelihood of a peak load event on Xcel's system. Ten years of weather data were analyzed between 2015 - 2024 from Minneapolis-St Paul (MSP) Airport.[85] Average high temperatures occur in July at 83.5 degrees,[86] suggesting that temperatures below 90 degrees should not create peak load conditions. For example, at 85, 90, 95, and 100 degrees, the cooling degree days (CDD) are 20, 25, 30, and 35, respectively which correlates closely with energy use from air conditioning.[87] Compared to an 85 degree day, the cooling load at 95 degrees is approximately 50 percent higher, which means that summer peak load conditions are much less likely at 95 degrees compared to 85 degrees. Yet, these data demonstrate that only a high of 2.7 percent of hours in June are 90 degrees or warmer, which is shown in Figure 25. The number of hours drops to 0.8 percent of hours at 95 degrees, and close to 0 percent of hours at 100 degrees, with only 5 hours in the last 10 years at or above 100 degrees.

Figure 25: Percent of Hours of Hot Weather at MSP



Source: NOAA[88]

Probabilistically, the odds of having a peak load day are relatively small. When combined with the probability of an N-1 event happening during the same hours as a peak load event, the probability

[85] See Report FM-15. *Data Tools: Local Climatological Data.* National Oceanic and Atmospheric Administration, (2026), (hereinafter "NOAA FM-15 Report"). Available at: https://www.ncei.noaa.gov/cdo-web/datatools/lcd
[86] *Minneapolis/St. Paul Climate Data: Normals and Averages*. Minnesota Department of Natural Resources, (2023). Available at: https://files.dnr.state.mn.us/natural_resources/climate/twin_cities/ccjuly1991_2020.html
[87] *Overview: Residential Energy Demand Temperature Index*. National Oceanic and Atmospheric Administration, (2026). Available at: https://www.ncei.noaa.gov/access/monitoring/redti/overview
[88] NOAA FM-15 Report.

decreases even more. The Department acknowledges that when peak day outages happen, these are some of the worst outages because cooling is lost at the hottest time of the year. However, as discussed previously, localized outages do not disrupt other areas of the grid that still have service, and thus essential services and access to cool facilities are still available in other locations when these outages occur.

Table 7 shows the coincidence of N-1 outages with high temperatures that are associated with peak load events. For each outage, the table reflects the maximum temperature at MSP between the start of an outage and final restoration of service. MSP averages 0.8 and 2.2 hours per year of 99 and 98 degrees, respectively, which likely correspond to annual peak load events.[89] Of the **[TRADE SECRET DATA HAS BEEN EXCISED]** N-1 outages between 2020 and 2024, **[TRADE SECRET DATA HAS BEEN EXCISED]** happened at 100+ degrees, which would correspond with a likely peak load event. At 95+ and 90+ degrees, there were **[TRADE SECRET DATA HAS BEEN EXCISED]** outages per year, respectively, which correspond to **[TRADE SECRET DATA HAS BEEN EXCISED]** percent of all N-1 outages and **[TRADE SECRET DATA HAS BEEN EXCISED]** percent of all outages on Xcel's system. To re-state an earlier point, with an average high July temperature of 83.5 degrees, Xcel's feeders should be nowhere near their peak load, otherwise there would be many more overload outages than the current average of **[TRADE SECRET DATA HAS BEEN EXCISED]** overload outages per day.[90]

Table 7: Number of N-1 Outages That Have Any Coincident With High Temperatures

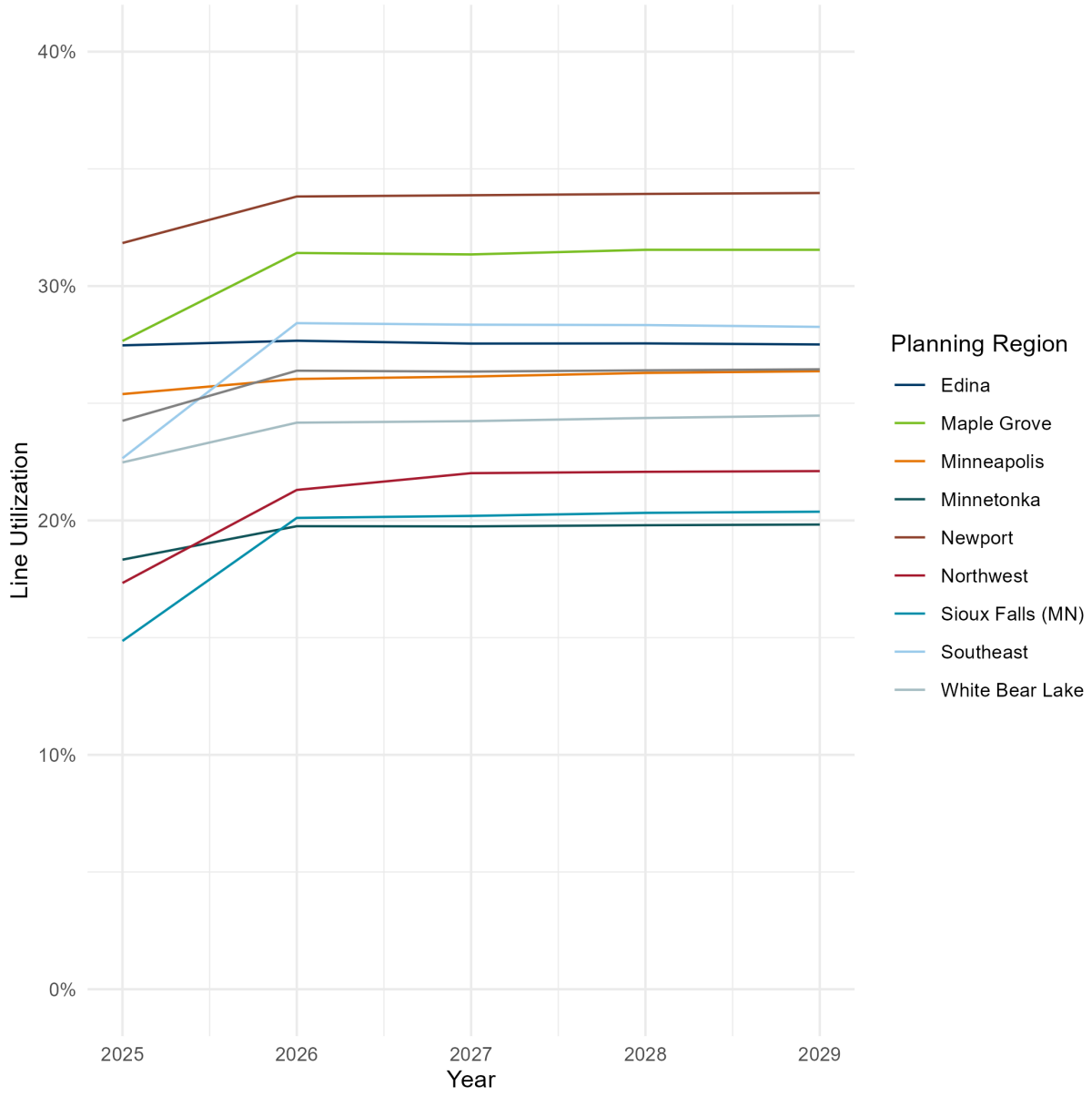
[TRADE SECRET DATA HAS BEEN EXCISED]

Outages that employ N-1 switching to restore service have an average CMO of **[TRADE SECRET DATA HAS BEEN EXCISED]** which has a reliability cost of **[TRADE SECRET DATA HAS BEEN EXCISED]** Near-peak outages that employ N-1 switching at or above 90 degrees have an annual cost of **[TRADE SECRET DATA HAS BEEN EXCISED]** The remaining**[TRADE SECRET DATA HAS BEEN EXCISED]** percent of outages that require N-1 switching at temperatures below 90 to 95 degrees therefore have extra headroom to relax the N-1 standard without the risk of capacity overload.

[TRADE SECRET DATA HAS BEEN EXCISED] Generally, most feeders in Xcel's territory have ample capacity for switching, as demonstrated by Xcel's line utilization data from IR 13 shown in Figure 26.[91]

[89] NOAA FM-15 Report
[90] *Ibid*.
[91] Attachment B – DOC IR 13, Attachment A. Note that Attachment A is not included in these comments, but can be provided upon request.

Figure 26: Xcel Line Utilization by Planning Division (Avg Energy Use / Rated Capacity)



The probability of rare N-1 peak day outages and their consequences must be weighed against Xcel's planned budget to mitigate these risks. Xcel plans to spend $293 million to mitigate N-1 risks listed in Attachment E,[92] which represents less than half of Xcel's 5-year capacity budget.[93] With an estimated annual N-1 risk capacity budget of $141 million,[94] it is important to evaluate whether these costs are

[92] 2025 IDP – Attachment E.
[93] Only $496 million of projects are listed in Attachment E, but Xcel's 5-year capacity budget is $1,193 million. See 2025 IDP – Figure 6-3.
[94] This estimate applies the known N-1 capacity budget proportion to Xcel's full 5-year capacity budget.

proportional to an estimated annual N-1 peak day outage cost of **[TRADE SECRET DATA HAS BEEN EXCISED]**. While a relaxation of the N-1 standard will increase the risk of N-1 outages, the risk is far lower compared to the risk of N-0 outages. Given the low risk of coincident peak day N-1 outage events, a cost-benefit analysis of both the N-1 standard and individual mitigations is warranted to ensure that N-1 risks are mitigated cost effectively.

The analysis in this section should not assume that Xcel's N-1 planning standard is flawed. Weather data is not a substitute for actual load on Xcel's system, but it does provide valuable insight about the probability of peak load events on Xcel's system, given that heat waves are highly associated with peak load events due to increased air conditioning.[95,96] The Department intends by this analysis to demonstrate the need to review Xcel's N-1 planning standard. Given that Xcel's N-1 risk planning assumptions appear to be highly conservative, the Department seeks to understand whether they are worth all of the extra capital spending to mitigate a relatively low risk of outages.

G.3. Capacity Forecast Error

In Section III.F, the Department recommends a new filing requirement for forecast error:

> The Department recommends the Commission create a new IDP filing requirement to provide a comparison of forecast accuracy for each vintage and scenario (IDP Low, Medium, High) in Xcel's LoadSEER forecasts compared to actuals.

To put this filing requirement in context, a 6.1 percent Year 1 forecast error,[97] which Xcel reports in Table 1-11 of its IDP, at 75 percent feeder loading, is equivalent to a modeled feeder loading of 79.6 percent of rated capacity. In contrast to the discussion around analyzing an N-0 standard of 80 percent, which is functionally equivalent to Xcel's Year 1 forecast error, there is essentially no marginal overload risk to fixing Xcel's forecast because the forecasted load is not accurate. Xcel's 10.1 percent Year 2 forecast error is equivalent to a forecasted load of 82.6 percent of rated capacity, when the actual load is at 75 percent of rated capacity. To reframe these numbers, at a 6.1 and at a 10.1 percent error, Xcel will trigger capacity upgrades, on average, at 70.7 and 68.1 percent of rated capacity, respectively, due to its forecast error.

Given the discussion regarding the analysis of an N-0 minimum loading of 80 percent, this forecast error may trigger upgrades a decade before they are needed, which could increase spending by hundreds of millions of dollars, all to mitigate risks that do not exist.

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[95] Anderson, Jared and Daryna Kotenko*. Major heat wave drives up power demand, prices across US MidAtlantic, Northeast*. S&P Global, (June 23, 2025). Available at: https://www.spglobal.com/energy/en/news-research/latest-news/electric-power/0623, 25-major-heat-wave-drives-up-power-demand-prices-across-us-midatlantic-northeast

[96] Ennis, Tim and Connor Waldoch. *Early Season Heat Stressed The Eastern Interconnection*. Grid Status Exports, (June 27, 2025). Available at: https://blog.gridstatus.io/early-heat-stressed-the-eastern-interconnect/

[97] 2025 IDP - Chapter 1 at 77.

Xcel opposes the Department's recommendation for a new filing requirement on forecast accuracy. In response to the Department's request for the filing requirement in Xcel's Proactive Upgrade Proposal comment period, the Company states:

> Additionally, a retrospective forecast accuracy assessment on the distribution system is complex and very different than a retrospective comparison of forecasts at the bulk system because:
>
> • Scenario bands are not point predictions. LoadSEER develops ranges – Low/Medium/High – precisely because distribution-level demand is driven by uncertain factors, including weather variability, customer electrification adoption, DER interconnections, and economic activity. Scenario bands are intended to bound plausible futures, not to predict a single "correct" outcome against which accuracy can be scored. An after-the-fact accuracy exercise risks penalizing reasonable planning judgment simply because exogenous conditions evolved toward one tail of the distribution.
>
> • Electrification and DER adoption introduce structural uncertainty. Our distribution forecast is intentionally built around clusters of customers adopting certain technologies—because in practice, adoption rarely occurs smoothly or uniformly across the system. Instead, electric vehicle charging, heat-pump conversions, commercial and industrial electrification, and distributed storage often emerge in localized pockets. These clusters can rapidly and nonlinearly alter feeder-level trajectories. As a result, even small concentrations of new load or new interconnections can materially shift outcomes relative to a prior median scenario, even when the underlying modeling and assumptions were sound.
>
> […]
>
> • The burden is disproportionate to the benefit. Producing feeder-specific, multi-year look-backs would be highly resource-intensive. It would require normalizing for weather, customer changes, behind-the-meter resource adoption, and code or standards changes—much of which is not readily available in a form that allows for efficient retrospective reconstruction. Significant manual effort would also be needed to validate and align the reconstructed data with historical operating conditions. Completing this work at the feeder level would require additional staffing yet would offer limited value for forward-looking proactive planning, where future uncertainty—not detailed historical reconstruction—is the primary driver.[98]

[98] Xcel, Reply Comments, February 18, 2026, Docket No. E002/M-25-142, (eDockets) 20262-228292-01 at 7-8.

Here, the Department respectfully disagrees with Xcel. The filing requirement is intended to track feeder-level forecast accuracy to determine if there is systematic bias in LoadSEER. As the Department discussed in its Initial Comments on Xcel's Proactive Upgrade Proposal, LoadSEER itself appears to be the source of the forecast error. Local variations in new customer load are not important at a system-wide level. In addition, factors such as weather, economic conditions, and other exogenous variables can be used to ascertain the relative contribution of forecast error from other sources, but these factors only indicate areas for improvement in Xcel's forecasting. Xcel's system-wide forecasts are generally very accurate, particularly in the short term when Xcel makes its capacity budget decisions. Therefore, the Department expects that other forecasting assumptions that are unique to LoadSEER are the driving factor for Xcel's forecast inaccuracy.

The Department also seeks to conduct a more thorough analysis of Xcel's forecast accuracy to determine the drivers of the forecast inaccuracy in Xcel's capacity planning standard review. Forecast accuracy currently trends in the wrong direction. The Department seeks to understand how Xcel can modify its LoadSEER modeling process to converge its average LoadSEER accuracy to its average system-wide forecast accuracy. If Xcel does not have the resources to perform this analysis itself, the Department can conduct this analysis if Xcel provides the necessary data.

In response to Xcel's last bullet point above, the burden is indeed disproportionate to the benefit— in the opposite direction Xcel states. Given the financial consequences of Xcel's forecast inaccuracy, any resources that Xcel or the Department devote to an analysis of forecast accuracy will likely yield far greater cost savings to ratepayers.

G.4. Sizing During Asset Replacement

Xcel is planning for a massive expansion of its distribution grid. The Company states:

> Across all three scenarios, the forecast shows distribution system growth from approximately 8.5 GW today to between 9 and 10 GW by 2035. This projected increase of 0.5 to 1.5 GW over the next ten years is substantial. To put this into perspective, a 1 GW increase would require *at least* 10 new substations, 20 new substation transformers, and 150 new feeders to support the additional load. This level of infrastructure investment highlights the urgency and importance of proactive planning and flexible budgeting.[99]

In IR 70, Xcel explains how the Company plans its future capacity needs.

> There is no single rule for sizing mitigations to a specific forecast year. The appropriate design horizon depends on the type of project and system conditions. For example feeder-level projects may only use a 5-10 year horizon, while larger infrastructure additions—such as new substations or

[99] 2025 IDP – at 7.

> transformer additions—are generally designed to meet needs across a 10-30 year horizon.
>
> In all cases, the goal is to design solutions that meet future needs, avoid premature rebuilds, and serve as building blocks for long-term plans. Customer load patterns, new development, and DER adoption can change from year to year, which is why planning is revisited annually. As a result, while a mitigation may align with today's forecast, that forecast may evolve, and design decisions must balance long term needs with prudent investment.[100]

2035 is less than ten years away, and Xcel's forecast after 2035 will continue to expand after that time. Load growth is also unlikely to materialize evenly throughout Xcel's system, with parts of Xcel's distribution system expanding relatively rapidly, and other parts with flat or slower growth. Given that Xcel may only use a 5- or 10-year forecast to size its feeders, these sizing assumptions may prove to be too short-sighted to plan for future load growth. The Department is well aware that Xcel's forecasts are uncertain, but given that distribution asset lifespans typically range between 30 to 50 years, the risk of premature asset replacement is high, given Xcel's load growth forecast. While Xcel explains that it does not have strict rules for how assets are sized when they are replaced, these general statements are concerning.

Xcel does not present analysis of different methods on how the company sizes, or could size its equipment for future capacity needs. The only effective way to determine the optimal sizing strategy is to test different assumptions about asset sizing with different assumptions about forecasts. Different scenarios will yield valuable insight about the future costs of asset replacement if Xcel sizes its assets too conservatively, or too liberally. While sizing assumptions during decades of relatively flat load growth were effective in the past, there is a need to revisit these assumptions given the large amount of load growth Xcel expects on its system.

G.5. Project Prioritization

In Attachment E, Xcel lists 193 projects that have been identified for capacity upgrades, with a total budget of $496 million. Xcel calculates a benefit-cost ratio of its capacity projects with a metric it calls the Risk Score.[101] Of these projects, $290 million have a Risk Score of less than 1, and $206 million have a Risk Score of 1 or greater. Xcel explains why over half of its projects have a BCR of less than 1:

> Over half of the selected projects have risk scores below 1.0 because the Capacity Risk Score is only one factor in project prioritization. As outlined in Attachment D of the IDP, other factors include mandates, new business,

[100] Attachment B – DOC IR 70.
[101] 2025 IDP – Attachment D at 1.

> asset health, blanket projects, and program needs. These factors often drive project selection even when the calculated risk score is relatively low.
>
> It is not possible to precisely delineate spending between these factors because many projects deliver overlapping benefits. For example, replacing a transformer may provide capacity, asset health, and operational benefits, but it is accounted for in a single project.
>
> The Capacity Risk Score model is a prioritization tool, not the sole determinant. Engineering judgment is also applied to ensure that our distribution grid evolves to accommodate new load, integrate DERs, and maintain safety and reliability. This includes addressing public and employee safety, improving resilience and enabling timely customer connections—all of which may justify selecting projects with lower risk scores.[102]

The Department understands that project needs beyond capacity are important considerations for project selection, and that a BCR of 1 or higher is not necessary to justify all projects. However, when the Department asked Xcel if a capacity-only project had a Risk Score of 0.75, if the Company would still conduct the project, the Company responds:

> While Table 1-12 provides N-0 and N-1 load limit thresholds, these thresholds do not operate as automatic triggers for funding a mitigation. Similarly, risk scores do not function as strict pass–fail criteria. It is important to note that a risk itself does not receive a score; instead a mitigation project, which may address multiple risks, receives an aggregated risk score. Over time, all risks get included in the budget and eventually become associated with a mitigation project.[103]

Xcel refuses to answer the Department's question, but implies when it says, "[o]ver time, all risks get included in the budget and eventually become associated with a mitigation project," that projects with Risk Scores below 1 will get mitigated, even if a Risk Score indicates that the projects are not cost effective. Xcel reaffirms this practice in its response to IR 68, where it states that the risk score "does not serve as a pass–fail test or allow the Company to exceed its N-0 or N-1 planning limits if a mitigation is not considered cost effective."[104] Xcel affirms that it will mitigate all N-0 and N-1 risks even if the projects are not cost effective.

Based on Xcel's responses, the Department concludes that Xcel's Capacity Risking Scoring Methodology is solely used for project prioritization, and is not a cost-benefit analysis. Therefore, every N-0 and N-1 risk that Xcel identifies will get mitigated eventually, and the risk score helps Xcel choose which

[102] Attachment B – DOC IR 61.
[103] Xcel notes its objection to the IR as speculative. See Attachment B – DOC IR 67.
[104] Attachment B – DOC IR 68.

projects to mitigate first, based on estimated consequences. Xcel's N-0 and N-1 standards themselves are therefore the only factor that determines whether a risk needs to get mitigated or not. Furthermore, a relaxation of the N-0 standard may not produce any benefit if the N-1 risk increases and pushes N-0 mitigates to N-1 mitigations.

As the Department's analysis shows, the risk of N-0 and N-1 capacity overload events is far from equal. N-0 overloads should be expected in the near-term, while N-1 overloads may happen much less frequently. Because the risk between N-0 and N-1 events is not equal, it is appropriate to consider whether Xcel should use a cost effectiveness test for its N-1 projects, which does not automatically qualify every N-1 risk as requiring a mitigation. An appropriate probability of an N-1 overload can indicate whether N-1 risks are cost effective to mitigate, however Xcel's current methodology appears to over-estimate N-1 risks, which could result in many mitigations that are not cost effective.

The Department again does not advocate for Xcel to change its project prioritization process in these comments. Instead, the Department advocates to study whether it could be net beneficial to ratepayers to screen N-1 projects based on their cost effectiveness. Xcel's current prioritization process can be adapted to add cost-effectiveness screens.

G.6. Scenario Analysis

The Department's analysis highlights the need to develop methods to test the efficacy of different planning standard practices. The Department intends to test scenarios that include both the sensitivity of planning standards, as well as different inputs, such as more conservative or liberal forecast assumptions. If the Commission accepts the Department's recommendations for a planning standard review process, the Department includes a list of the following capacity planning standards for review that would be presented for Commission decision in the 2027 IDP.

The Department recommends the Commission order a review of the following capacity planning standards, to be presented in Xcel's 2027 IDP:

A. Capacity forecasting and accuracy
B. N-0 forecast uncertainty margin and the use of AMI or other actual data
C. N-1 probability of coincident peak load and N-1 contingencies
D. N-1 screening based on cost effectiveness
E. Sizing new assets for future load growth
F. Capacity Risk Framework
G. Project Prioritization

There is an opportunity for Xcel and intervenors to collaborate on model development and testing of planning standards, similar to the IRP process. Xcel could develop one or more typical sections that are representative of its distribution system in a power flow model, similar to the results from NWA analysis. Xcel could then provide updated configurations of the typical sections with respective cost assumptions at different times to test its planning standards and inputs. While modeling will not be

required for a review of all of Xcel's capacity planning standards, a modeling process will be helpful to test certain standards such as N-1 contingencies and sizing assets for future load growth.

To facilitate the modeling process, and to provide expert engineering review of Xcel's planning standards, is currently considering a request for funding of contractual services. While the Department can request scenarios for economic analysis, there is value to verifying engineering practices from a third party. The Department may present a request for funding in supplemental comments.

H. WILDFIRE

The Department responds to the following notice topic:

> *Notice Topic 17: Other Areas of Xcel's IDP Not Listed Above, Along with Any Other Issues or Concerns Related to This Matter.*

Xcel provides a brief discussion of its wildfire mitigation strategy in its IDP. Previous IDPs have not addressed wildfire mitigation, as Xcel's proposal is an entirely new cost category and topic for discussion. The following table represents Xcel's wildfire capital expenditures for the IDP planning horizon (2025-2030). The proposed five-year budget totals $926,464,011. Given this brand new, and substantial budget category, there is a need to ensure that all of the proposed funding is necessary. The size of this new budget category raises important affordability concerns.

Table 8: Xcel Table 2-3 Wildfire Expenditures (2025-2030)

Table 2-3[14]
Wildfire Expenditures (2025-2030)

Year	2025	2026	2027	2028	2029	2030
Capital	$92,135,000	$232,966,000	$214,463,003	$137,900,002	$124,500,003	$124,500,003
O&M	$2,637,000	$4,697,000	$6,190,000	$2,616,000	$2,749,000	$2,749,000

Source: 2025 IDP, Chapter 2, Table 2-3 at 29.

H.1. Summary of Strategy

Xcel employs a layered wildfire mitigation strategy that includes tools such as system hardening, situational awareness, operational protocols, and community engagement.[105] Xcel states its approach is designed to reduce ignition risk, enhance system resilience, and protect public safety, all while maintaining a high level of customer service.[106] Xcel commenced a mapping process to geographically indicate three tiers of wildfire risk for its Minnesota territory: Tier 1 (Low Risk), Tier 2 (Medium Risk), and Tier 3 (High Risk).[107] Its map incorporates data layers such as vegetation type, historical fire data,

[105] 2025 IDP – Chapter 2 at 24.
[106] *Ibid.*
[107] *Id.,* at Chapter 2, 25.

topography, and infrastructure density. Xcel states its map is reviewed annually to determine if updates are necessary. Through this mapping effort, Xcel identified that 107,000 of its poles are located within Tier 2 and 4,700 are in Tier 3.[108] In Supplemental Direct Testimony filed by Xcel in its ongoing rate case, Witness Bloch states the number of poles located in Tier 3 is now 5,000 poles. This revision is due to the operationalization of the Xcel's wildfire risk area map that allows a Geographic Information System review of the specific assets located with each tier. The number of poles within Tier 2 remains the same at 107,000 poles.[109]

Xcel discusses its mitigation measures in five main categories within its IDP: Situational Awareness Tools, System Resiliency Enhancements, Vegetation Management, Operational Mitigations and Distribution System Upgrades, which are addressed in turn below.

H.1.1. Situational Awareness Tools

Situational Awareness Tools include modeling software to simulate fire behavior under various environmental conditions to predict spread and intensity, weather stations, AI-Enabled Cameras to detect smoke and fire, as well as both high impedance fault detection and non-traditional fault detectors. Xcel states that each of these tools support early identification of ignition risks, enabling precise fault location and improving safety and restoration times.[110]

The Department issued IR 90 to gather further information regarding Xcel's proposed situational awareness tools, given the discussion of the tools was quite brief.[111]

The Department requested Xcel discuss further how its advanced fire modelling software will be utilized within the Company. Further, the Department asked Xcel to clarify if the software discussed within its IDP refers to the FireSight tool discussed in Sherwood's Supplemental Direct Testimony in the its ongoing rate.[112] Xcel incorrectly asserted that the Advanced Fire Modelling Software tool is not referenced in the IDP.[113] The Company also asserted that its use and costs are properly addressed within the its ongoing rate case and thus the Department's IR is outside of the scope of the IDP. Xcel goes on to confirm that the Advanced Fire Modelling Software is the FireSight tool that is included in the rate case.[114]

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[108] *Id.*, at Chapter 2, 26.
[109] *In the Matter of the Application of Northern States Power Company for Authority to Increase rates for Electric Service in Minnesota, Bloch Supplemental Direct Testimony and Schedules*, Northern States Power d/b/a Xcel Energy, March 17, 2025, M002/GR-24-320, (eDockets) 20253-216469-07, (hereinafter: "Bloch Supplemental Direct") at 8.
[110] 2025 IDP – Chapter 2 at 27.
[111] Attachment B – DOC IR 90.
[112] *In the Matter of the Application of the Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota*, Sherwood Supplemental Direct Testimony, Northern States Power d/b/a Xcel Energy, March 17, 2025, Docket No. E002/GR-24-320, (eDockets) 20253-216469-06, at 8.
[113] Attachment B – DOC IR 90; 2025 IDP – Chapter 2 at 27. Note: The "Advanced Fire Modelling Software" is referenced as a situational awareness tool as part of the Company's Wildfire Mitigation Strategy.
[114] Attachment B – DOC IR 90.

In the same IR, the Department asked Xcel if it had completed any studies within its Minnesota territory to determine the effectiveness of its proposed AI cameras in detecting smoke or fire signatures. The Department also asked Xcel to propose reporting metrics for its proposed AI camera project. Xcel responded that it has not completed any studies within its Minnesota territory to demonstrate the effectiveness of its proposed cameras. Further, Xcel states that the AI camera project is included in the wildfire mitigation budget at issue in its ongoing rate case. As such, Xcel states it cannot meaningfully determine which technology will be implemented, nor the metrics that would be appropriate for ongoing reporting in future IDPs.[115]

H.1.2. System Resiliency Enhancements

Xcel discusses infrastructure upgrades it deems essential to reducing wildfire risk and improving reliability. These measures include asset inspection and repair/replacement, pole loading and clearance (using LiDAR to create 3D models of distribution lines to analyze structural integrity and clearance), system hardening, and non-expulsion equipment replacement.[116]

The Department issued IR 91 to gather additional information regarding the Xcel's proposed system resiliency enhancements, given the discussion of the enhancements in the IDP was quite brief.

The Department asked Xcel to discuss how the system resiliency enhancements proposed as part of its wildfire mitigation strategy differed from traditional resiliency efforts it has conducted. The Department also asked Xcel to clarify whether it is employing its system enhancements proactively, or as assets become due for replacement—if proactively, the Department asked for the criteria utilized to determine where to employ the enhancements.[117]

Xcel states in IR 91 that its System Resiliency Enhancements differ from traditional resiliency programs by specifically focusing on both proactively inspecting and replacing poles as well as replacing primary and secondary conductors in Tier 2 and 3 areas based on wildfire risk (Xcel will prioritize Tier 3 and then Tier 2).[118] Unlike traditional system resiliency efforts, Xcel states System Resiliency Enhancements would be focused on areas of heightened wildfire risk and would include a larger volume of work or a higher cadence of inspection due to heightened wildfire risk.[119]

In reference to overhead pole assessments, for example, Xcel would inspect all Tier 3 poles every 3 years (one third of the poles per year) and all Tier 2 poles every six years (one sixth per year. Its approach to inspections specific to its wildfire mitigation strategy, Xcel states, results in a higher inspection cadence and detailed evaluation along wildfire-risk feeders than traditional resiliency programs.[120] With respect to pole loading and clearance (PLC) efforts, LiDAR-based drone inspections

[115] *Ibid.*
[116] 2025 IDP – Chapter 2 at 27.
[117] Attachment B – DOC IR 91.
[118] *Ibid.*
[119] *Ibid.*
[120] *Ibid.*

would be employed to evaluate five percent of all Tier 2 and 3 poles annually—an inspection cadence not currently utilized by Xcel. Xcel states this annual inspection rate would provide the earlier identification and remediation of structural loading issues and clearance violations in areas of heightened wildfire risk. On the matter of Small Wire, Covered Conductor and Open-Wire Secondary Replacement programs, Xcel states the programs target older, less durable primary and secondary conductors before the end of asset life in Tier 2 and 3. Xcel states these replacements are planned proactively and at a larger scale, with annual targets for conductor replacements.[121]

H.1.3. Vegetation Management

Xcel states vegetation management is the leading cause of utility-related wildfires. Xcel states its vegetation management strategy includes conductor clearance, clearing flammable materials from around poles and execution of hazard tree work. Xcel states the vegetation management work is tailored to local vegetation types and growth patterns, with a focus on high-risk areas identified through its mapping effort of wildfire risk tiers. [122]

The Department issued an IR to gather additional information regarding Xcel's proposed vegetation management component of its wildfire mitigation strategy. The Department requested Xcel discuss how its vegetation management strategy differed from the management plan included in its annual Safety, Reliability and Service Quality Report (SRSQ).[123] In its response, Xcel states that its SRSQ only contains a brief description of its vegetation management plan, whereas the IDP provides a more comprehensive description of the plan and its timing. The vegetation management plan in the IDP, states Xcel, describes a hybrid approach that utilizes both time-based cycles of management as well as risk-based modeling supported by tools like AI analytics and satellite imagery.

H.1.4. Operational Mitigations

Xcel identifies two operation mitigations including Enhanced Powerline Safety Settings (ESPS) and Public Safety Power Shutoffs (PSPS). ESPS modifies protection schemes to direct faults more quickly and block automatic reclosing whereas PSPS temporarily de-energizes lines in extreme fire and weather conditions to prevent ignition.[124]

Xcel states its PSPS measures are coordinated with local emergency services and communicated with affected communities to ensure safety and minimize disruptions.[125]

The Department issued IR 93 to gather additional information on Xcel's proposed operational mitigations. The Department asked Xcel to provide additional context as to when an ESPS and a PSPS event would be called, including how it communicates with affected customers, state and local

[121] *Ibid.*
[122] 2025 IDP – Chapter 2 at 28.
[123] Attachment B – DOC IR 92.
[124] 2025 IDP – Chapter 2 at 28.
[125] *Ibid.*

governments, and local emergency management. The Department asked what strategies Xcel employs to mitigate harm to customers in the event of a PSPS event. The Department is especially concerned for particularly vulnerable customers in the event of a PSPS, such as those whose electric service is medically necessary, including large critical institutions such as hospitals or nursing homes.[126]

In response to Department IR 93, Xcel states that it may implement EPSS or PSPS depending on wildfire risk due to wildfire weather conditions described in its Wildfire Safety Operations (WSO) Playbook. In response to the questions about how PSPS is utilized and communicated, Xcel cited its PSPS Playbook and the associated PSPS Communications Playbook. The Company does not include these Playbooks as attachments or direct the Department to a location where the documents can be found.[127]

In response to the Department's question regarding medically dependent electric customers, including commercial customers such as hospitals and nursing homes, Xcel stated its medically necessary equipment certification form allows the Company to identify where on the system those customers are located. However, the locational information gathered from the form is not currently integrated into the Company's wildfire mitigation plan. Xcel states that most critical facilities, such as hospitals and nursing homes have back up generation.[128]

Although it may be true that most facilities with medically dependent residents will have back up generation, it is less likely that residential customers will have access to back up generation in the event of an outage. Xcel states that it has locational information related to its customers that have submitted a medically necessary equipment certification form, but that the information is not integrated into its wildfire mitigation plan. The Department concludes that in the event of a wildfire, and a possible operational mitigation resulting in a shutoff, it is paramount to know if or how an emergency shutoff could affect Xcel's most vulnerable customers. A power outage for customers whose electric service is medically necessary is a significant risk to health and safety and should be avoided if possible. Xcel cannot avoid power shutoffs to these customers if it does not inform its wildfire mitigation plans with the locational information provided by its medically necessary equipment verification form.

The Department recommends Xcel integrate the locational information from its medically necessary equipment certification form into its wildfire mitigation plan.

H.1.5. Distribution System Upgrades

Xcel states that it is investing in targeted upgrades to reduce ignition risk and improve system durability. The targeted upgrades include small wire conductor replacements, covered conductor

[126] Attachment B – DOC IR 93.
[127] *Ibid.*
[128] *Ibid.*

installations and, again, non-traditional fault detectors. Xcel states its targeted upgrades are prioritized in Tier 2 and Tier 3 and are aligned with broader Company reliability and resiliency goals.[129]

The Department issued IR 94 to gather additional information regarding Xcel's targeted distribution upgrade efforts to reduce ignition risk. The Department asked Xcel if the upgrades are being completed proactively or when the assets become due for replacement. The Department also asked Xcel to clarify how it prioritizes its targeted distribution upgrades.[130]

Xcel states that the distribution system upgrades identified within its wildfire mitigation plan are being performed proactively, guided by the risk tiers identified by its wildfire risk map. In tiers 2 and 3, Xcel evaluates both inherent wildfire risk and the condition of existing distribution assets. Xcel states it incorporates additional factors—including outage history and current distribution asset health—to identify specific conductors, poles, and equipment in need of replacement. Although many of the upgrades may coincide with assets approaching repair or replacement cycles, Xcel asserts the goal is proactive mitigation of wildfire ignition rather than routine asset renewal alone.[131]

H.1.6. Conclusion

While the Department was able to gather more information on the IDP categories of wildfire investment through IRs, the information included in the IDP and gathered through Department IRs does not constitute a robust plan that is fully optimized. Furthermore, it is unclear what issue(s) Xcel's wildfire mitigation plan is trying to address. For example, limiting Xcel's liability related to utility-caused wildfires may be an entirely different value proposition than preventing wildfire damage to utility infrastructure; the different elements of a wildfire mitigation strategy may be more or less beneficial based on the intent of Xcel's plan. Currently, the benefits and actual mitigation potential of the Company's wildfire strategy are limited and require additional development.

H.2. Overlap with Rate Case

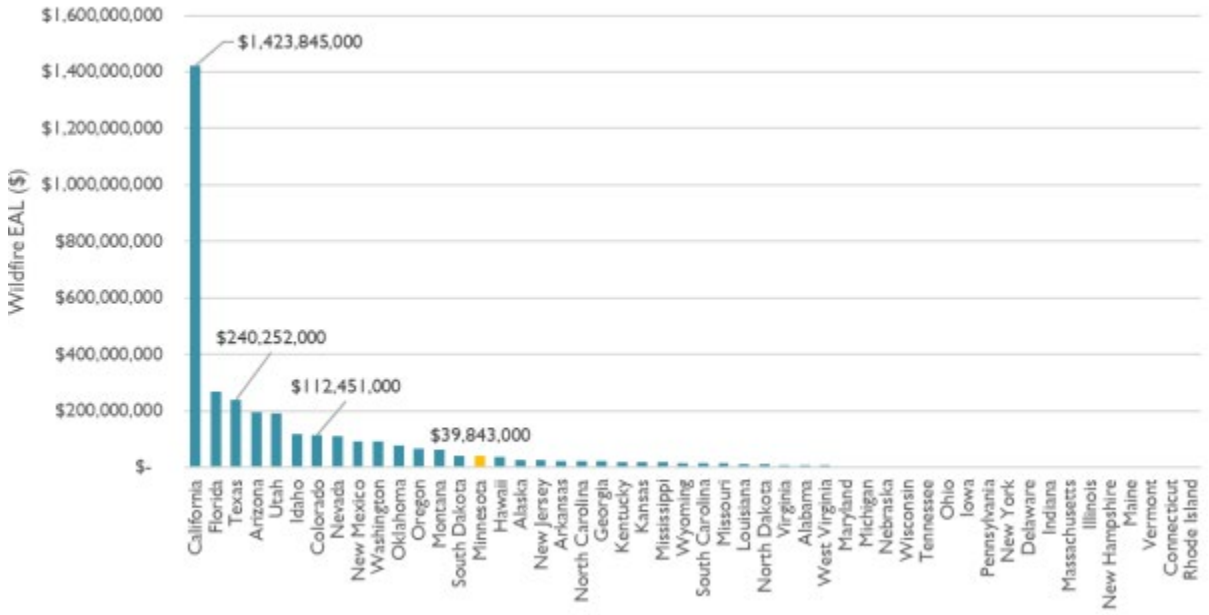
H.2.1. Department Testimony

Xcel states that Table 2-3 of its IDP presents its most current (at the time of IDP filing) wildfire expenditures and states the same expenditures were also included in its ongoing rate case. As such, a segment of Xcel's wildfire spending is under review and is subject to an ultimate Commission decision in the rate case proceeding. The expenditures included in the rate case may vary slightly due to the timing of the IDP filing. [132] The Department discusses the ongoing rate case herein as it relates to the development of the IDP record regarding the Company's wildfire mitigation plan.

[129] 2025 IDP – Chapter 2 at 28-29.
[130] Attachment B – DOC IR 94.
[131] *Ibid*.
[132] 2025 IDP – Chapter 2 at footnote 14.

Department Witness Borden covered several recommendations regarding Xcel's proposed wildfire budget in its ongoing rate case.[133] The Department concluded in the ongoing rate case that Xcel had not adequately justified its wildfire mitigation proposals.[134] Borden provides analysis of Minnesota's wildfire risk compared to the other states Xcel serves, Texas and Colorado, within his Direct testimony utilizing the FEMA National Risk Index. The FEMA National Risk Index models annualize frequency of wildfires, historic loss data, and exposure to estimate expected monetary damages from lost agriculture, buildings and lives.[135] Minnesota's wildfire Expected Annual Loss (the average annual economic loss in dollars resulting from natural hazards) is three times lower than that of Colorado and six times lower than that of Texas.[136] FEMA ranks Minnesota in the top 15 states in the U.S. for wildfire risk, but its risk is substantially lower than that of the highest risk states.[137] Figure 27 from Borden's direct testimony depicts Wildfire Expected Annual Loss (EAL) by state in 2022 dollars, showing Minnesota highlighted in yellow.[138]

Figure 27: Borden's Figure 1 – Wildfire EAL by State (2022 dollars)



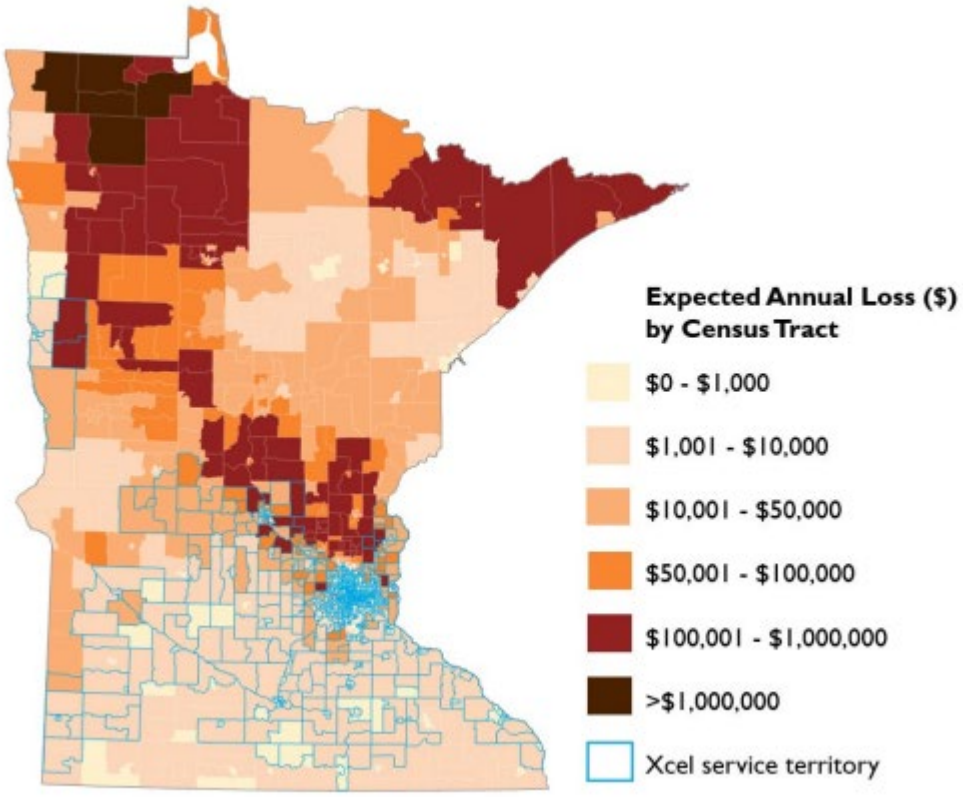
Source: Borden Direct – at 12.

Further, Borden demonstrates in direct testimony that wildfire EAL significantly varies across the state of Minnesota. Wildfire risk within Minnesota is highest in the northern part of the state, not within

[133] Borden Surrebuttal – at 29-30.
[134] *Id.,* at 1-2.
[135] Borden Direct – at 11.
[136] *Id.,* at 12
[137] *Ibid.*
[138] *Id.,* Figure 1 at 12.

Xcel's territory.[139] Figure 28 below depicts wildfire EAL by census tract. Xcel's territory, located in the southern part of the state, contains 19 percent of the statewide wildfire EAL ($7.5 million vs. $39.8 million, respectively).[140]

Figure 28: Borden's Figure 2 – Wildfire EAL in and outside of Xcel's Minnesota Service Territory (2022 dollars)



Source: Borden Direct – at 13.

Additionally, Borden examined wildfire data from the Minnesota Department of Natural Resources (MN DNR). The MN DNR collects data on historical fires, causes of ignition, and related damages.[141] Borden's analysis showed that utility transmission and distribution lines caused a very small fraction of fires within Minnesota from 2018 to 2025—annually, between only 3.5 and 6.3 percent were caused by utility power lines.[142] Overall, the Department concluded within the rate case that Minnesota's wildfire risk is relatively low compared to the western states in which Xcel also has service territory and risk within Xcel's Minnesota service territory is lower still.[143]

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[139] *Id.*, at 13.
[140] *Ibid.*
[141] *Id.,* at 14-15
[142] *Ibid.*
[143] Id., at 19.

Based on the Department's analysis within Xcel's ongoing rate case, it is clear Xcel incorrectly incorporated Minnesota's wildfire risk and the relative wildfire risk to its own service territory into its wildfire mitigation proposals. The same proposals were included in the IDP. It is also crucial to note that the proposals Xcel has included in its IDP and in its rate case are in addition to Xcel's preexisting Public Safety Power Shutoff Program (PSPS). The PSPS program shuts off power to customers during high-risk weather events, in order to prevent catastrophic ignitions.[144] As stated in Borden's Direct Testimony, "[s]ince the Public Safety Power Shutoff (PSPS) program reduces the majority of wildfire risk, incremental risk reduction from additional programs will be limited."[145]

Yet, given that some of Xcel's territory does exhibit high wildfire risk, the Department supports implementing a scaled back version of Xcel's proposals to address the highest-risk infrastructure in the rate case.[146] Department Witness Borden recommends the following regarding Xcel's wildfire mitigation plan in its pending rate case:

- The EPSS (Enhanced Powerline Safety Settings) and OPA (Overhead Pole Assessments) programs should be scaled back to address only Tier 3 Xcel's service territory, rather than implementation across all Tier 2 and Tier 3.
- The Wildfire Corridor program should be implemented on half of Tier 3 miles to test the program for efficacy and implemented over two years.
    - The Company should trim other areas where EPSS is implemented to the current clearance standard of six feet.
- The line rebuild program and associated pole replacements should be scaled back to 50 percent of the Company's proposal to better inform key assumptions and collect data on the cost-effectiveness of this program.
- Vegetation management costs should be treated as operations and maintenance (O&M) expenses.[147]

On December 12, 2025, Xcel filed a letter in its ongoing rate case to inform parties and the CAH (Court of Administrative Hearings) of its revised position on its wildfire related costs for the 2025 test year and the 2026 plan year. The Company states it reviewed the Surrebuttal Testimony of Department Witness Borden, agreeing that the recommendations are important foundational work. The Company states:

> For purpose of this case, in the interest of narrowing contested issues, we agree the overall costs for the larger-scale wildfire programs presented in the Department's Direct Testimony and Surrebuttal Testimony are reasonable for inclusion in the 2025 test year and 2026 plan year. This will

[144] Borden Direct – at 6-7.
[145] *Id.,* at 3.
[146] Borden Surrebuttal – at 1-2.
[147] *Id.,* at 29.

> allow us to perform important mitigation activity in the near-term, with subsequent mitigation work to be developed as we increase our understanding of wildfire risk with enhanced risk modeling currently under development.[148]

The following table from Department Witness Borden's Surrebuttal provides a comparison of the budget proposed by Xcel and the Department's proposed adjustments.

Table 9: Department vs. Xcel Forecast Adjustments for Wildfire Mitigation Capital Additions and O&M Expense Reclassification of Select Categories ($ Million)

Adjustment Category and Year	Xcel		Department		Proposed Adjustment	
	2025	2026	2025	2026	2025	2026
EPSS Capital Additions (sub, line, fault detection, SCADA)	$28.70	$110.40	$15.61	$3.80	($13.09)	($106.60)
EPSS O&M Increase for Vegetation Management	N/A	N/A	$3.93	$3.93	$3.93	$3.93
OPA Capital Additions	$41.90	$38.10	$9.00	$0.00	($32.90)	($38.10)
OPA O&M Increase for Vegetation Management	N/A	N/A	$5.26	$5.26	$5.26	$5.26
Line Rebuild & Pole Replacement Capital Additions	$0.00	$39.30	$0.00	$19.65	$0.00	($19.65)
Total Capital Additions (Reduction)	$70.60	$187.80	$24.61	$23.45	($45.99)	($164.35)
Total O&M Expense Increase	N/A	N/A	**$9.19**	**$9.19**	**$9.19**	**$9.19**

Source: Borden Surrebuttal Testimony[149]

The Department issued IR 39 requesting Xcel revise its proposed wildfire expenditures within the IDP to reflect the recommendations of Department Witness Borden. The Department also requested a narrative discussion describing how the revisions proposed by Borden would impact Xcel's mitigation plans.[150] Xcel responded that it is not in a position to provide a revised budget or narrative regarding the impact of the revisions proposed by the Department because the rate case has not yet been decided. It also stated the Department's request is outside of the scope and purpose of the IDP

[148] *In the Matter of the Application of Xcel Energy, for Authority to Increase Rates for Electric Service in Minnesota,* Wildfire Letter, Xcel Energy, December 12, 2025, Docket No. E002/M-24-320, (eDockets) 202512-225803-01 (hereinafter "Xcel Wildfire Letter").
[149] Borden Surrebuttal – Table 2 at 30.
[150] Attachment B – DOC IR 39.

because the "IDP is intended to outline anticipated investments and strategies based on the best available information at the time of filing, enabling stakeholders to understand the Company's long-term vision and priorities."[151] Xcel further states that any approved changes from the rate case will be incorporated into the wildfire section of the next IDP.[152]

The Department appreciates Xcel's support of the Department's wildfire mitigation budget recommendations in the ongoing rate case. However, it is worth noting that the departure from Xcel's proposed budget to the recommendation of the Department is a substantial budget revision, as depicted in Department Witness Borden's Table 2 above. Although the IDP is a snapshot-in-time planning docket, a planning pivot of over two-hundred-million dollars to the capital costs for 2025 and 2026, changes the planning landscape significantly. It is reasonable to assume Xcel has evaluated, or should have evaluated, how pivoting to the Department's recommended wildfire budget would impact its mitigation plans into the future.

H.2.2. FireSight Tool

As discussed above in reference to Xcel's Situational Awareness Tools, Xcel mentions Advanced Fire Modeling Software as one of many components of its Wildfire Mitigation Strategy within the IDP.[153] In Xcel's rate case, Xcel Witness Sherwood states in Supplemental Direct Testimony that Xcel will be utilizing Technosylva's FireSight subscriptions-based information service to determine which assets are most likely to fail, have an outage, and/or cause an ignition. Xcel confirms in response to Department IR 90 that the FireSight tool is the Advanced Fire Modeling Software that is included in Xcel's IDP. Sherwood states that the analysis completed with the FireSight tool will help Xcel to calculate potential risk reduction for asset hardening projects. The FireSight tool, states Sherwood:

> [A]llows Xcel Energy to design mitigation projects to optimize mitigation effectiveness for asset hardening and vegetation management by prioritizing those assets with the highest expected risk by understanding the probability of a wildfire occurring from one asset over another to efficiently prioritize their grid-hardening and mitigation efforts.[154]

The Department issued IR 95 to gather additional information as to 1) how Xcel plans to utilize the FireSight tool, 2) what the outputs from the tool are, and 3) how Xcel will prioritize mitigation projects and calculate risk reduction. The Department also asked Xcel if the FireSight tool could be utilized to develop a portfolio of proposed wildfire mitigation proposals to be filed for review by the Commission.

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[151] *Ibid.*
[152] *Ibid.*
[153] 2025 IDP – Chapter 2 at 27.
[154] *In the Matter of the Application of the Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota*, Sherwood Supplemental Direct Testimony, Xcel Energy, March 17, 2025, Docket No. E002/GR-24-320, (eDockets) 20253-216469-06, (hereinafter "Sherwood Supplemental Direct") at 8.

Further, the Department asked Xcel to discuss what a potential portfolio of wildfire mitigation proposals could look like and where such a portfolio could be filed for Commission review.[155]

Xcel states that, because the FireSight tool is included in Xcel's ongoing rate case, it would be premature for it to define how FireSight would be utilized, what criteria would be applied, or how potential risk reduction would be calculated.[156] Xcel asserts that the ability to procure or implement FireSight will depends on the level of budget approved by the Commission within Xcel's rate case. Xcel, in its response to IR 95,

> [R]ecommends that the Department defer further inquiry into FireSight's specific functionality or implementation until (1) the wildfire mitigation budget is finalized in the rate case, and (2) the Company files a Wildfire Mitigation Plan that reflects the final approved budget and identifies the specific tools and strategies the Company will deploy. The Department's questions can be more effectively and accurately addressed at that time, once the Commission has issued its decision and the Company is able to present a more fully developed wildfire-mitigation strategy.

H.3. Department Recommendation

Xcel expresses in its December wildfire letter in its ongoing rate case that the Department's recommendations in Xcel's pending rate case allow it to:

> perform important mitigation activity in the near-term, with subsequent mitigation work to be developed as we increase our understanding of wildfire risk with enhanced risk modeling currently under development.[157]

Together, the response from Xcel to IR 95 regarding the FireSight tool, Xcel's December wildfire letter, and the lack of record development surrounding Xcel's proposed wildfire budget in the IDP indicate that the appropriate level of funding for wildfire mitigation in Xcel's territory is largely based on the analysis performed by the Department within the rate case and the level of funding ultimately approved by the Commission. Xcel is still working to establish evidence-based risk modeling and to understand the level of wildfire risk within its territory, as stated in its December wildfire letter.[158] The determination of the level of investment necessary for the provision of safe, affordable and reliable electric service is not the burden of the regulator. The burden of proof lies with the utility as to what level of investment is necessary to address a concern on its system.

[155] Attachment B – DOC IR 95.
[156] *Ibid.*
[157] Xcel Wildfire Letter.
[158] *Ibid.*

Xcel states in its response to IR 95 that it plans to file a Wildfire Mitigation Plan following the final decision in its pending rate case.[159] The Department concludes that additional record development ahead of any future cost recovery beyond the current rate case proceeding for wildfire expenses is paramount. Prior to the Department's analysis in the ongoing rate case, there had been no opportunity to review and provide feedback on Xcel's wildfire spending. Without a dedicated location to review future spending on wildfire mitigation, the only opportunity for substantial review will be in the contested case proceeding for cost recovery. The confines of a contested case proceeding can put great strain on stakeholders' time and resources across a range of interrelated and complex issues. The contested case arena should not be where stakeholders learn of and analyze multimillion-dollar proposals for the first time.

The Department continues to support its recommendations within Xcel's pending rate case but asserts that there is much work to be done in assessing any future need for wildfire spending in Xcel's service territory.

The Department recommends that future (outside of the current rate case's test and planning years) wildfire mitigation proposals be filed with the Commission as a comprehensive Wildfire Mitigation Plan. The Department recommends the Company's Wildfire Mitigation Plan be filed as an attachment or supplement to its IDP.

The Department recommends the Commission require Xcel to include the following in its Wildfire Mitigation Plan:

- **Of the overall Wildfire Mitigation Planning process:**
  - **A description of the intent of the Company in mitigating wildfire risk (i.e. mitigating utility-caused wildfires/minimizing liability or mitigating fire damage to utility assets),**
  - **A definition of "wildfire" as it is used for utility identification, planning and mitigation.**
  - **A discussion of its risk modelling, mapping and prioritization process within its Wildfire Mitigation Plan.**
  - **The most recent version of its wildfire risk map with a narrative explanation of the highest risk areas, and any changes from the last iteration of the Wildfire Mitigation Plan.**
  - **Reporting on the number and locations of wildfires experienced in its territory over the last ten years, the number of outages caused by wildfire, and the average length of wildfire-related outage.**
  - **Reporting on the efficacy of its wildfire mitigation strategy in reducing wildfire-related outages (i.e. After deployment of the rate-case-approved wildfire mitigation measures, wildfire-related outages in Xcel's territory decreased 50 percent; the number of wildfires in Xcel's service territory decreased from 100 to 50 since the filing of the Company's last IDP resulting in approximately 10 fewer outages.[160])**

[159] Attachment B – DOC IR 95.
[160] Values are arbitrary given as examples for how Xcel could demonstrate the efficacy of its Wildfire Mitigation Plan.

- **Discussion of its use of its Public Safety Power Shutoff Program, including the number of PSPS outages, cause of the PSPS outage, average length of a PSPS outage, if/how notice was provided to customers, and measures the Company employs to protect customers that are medically dependent on electric service.**
  - **Provide the Wildfire Safety Operations Playbook, the PSPS Playbook, and the PSPS Communications Playbook as attachments or provide the location where the Playbooks can be accessed.**

- **A full cost benefit analysis.**

However, if the Commission accepts the planning standard review recommendation as discussed in Section III.C, the Department concludes that its wildfire planning recommendations, outlined above, could be addressed there and do not need to be accepted independently. If the Commission does not accept the Department's planning standard review recommendation, the Department supports its wildfire mitigation plan recommendations as standalone options.

I. TARGETED UNDERGROUNDING PROPOSAL

The Department responds to the following notice topic:

> *Notice Topic 16.E: Feedback, Comments, and Recommendations on the targeted undergrounding proposal.*

Xcel proposes a large, discretionary, targeted undergrounding proposal that is aimed at improving system reliability. While the Department supports reliability improvement projects, these projects must be carefully scrutinized to ensure that the reliability benefits are optimized, such that rates do not increase without commensurate benefits.

I.1. Summary of Proposal

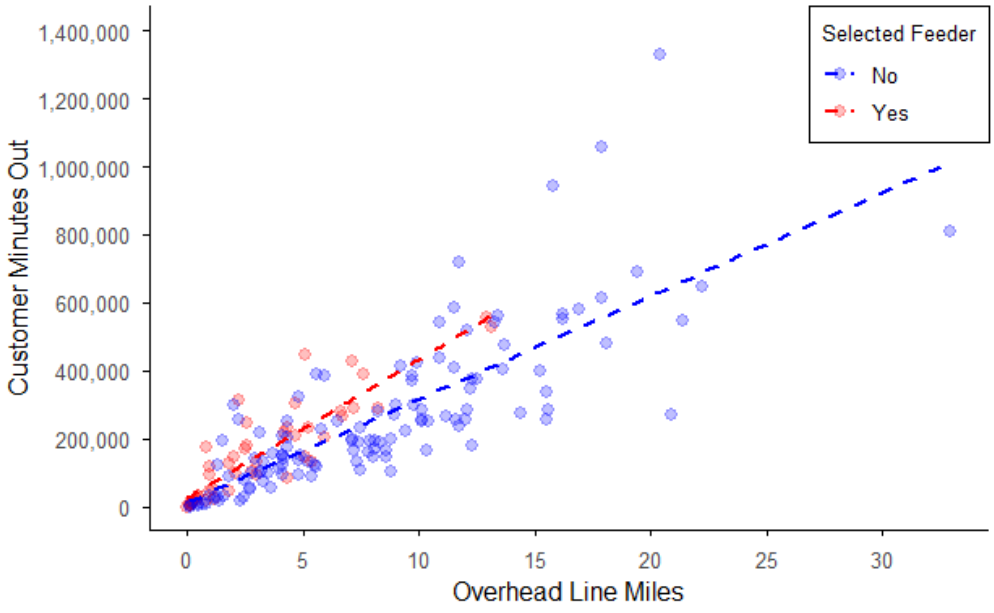
In its IDP, the Company proposes a Targeted Undergrounding Plan to serve as a long-term reliability initiative. This program focuses on relocating high-risk overhead distribution segments to "significantly improv[e] storm resilience, reduc[e] outages, and enhanc[e] public safety."[161] The Company describes full-scale undergrounding as "cost-prohibitive."[162] Instead, this strategic approach uses data-driven criteria, such as outage history and reliability metrics, to prioritize investments where they "deliver the highest reliability impact."[163] The plan follows a phased investment strategy from 2025 through 2030 with total capital expenditure of $233.7 million.

Figure 29 offers empirical support for the Targeted Undergrounding Plan through the demonstration of a clear correlation between overhead line miles and customer minutes out. The linear relationship confirms that feeders with extensive overhead infrastructure experience more significant service

[161] 2025 IDP – Chapter 2 at 5.
[162] *Ibid.*
[163] *Ibid.*

interruptions, which provides justification for the strategic relocation of high-risk segments to improve system resilience and reduce total outage durations. More importantly, the higher rate of accumulation for feeders selected for undergrounding (Selected Feeders 'Yes'), represented by a steeper slope, demonstrates that the First Targeting Method Scenario prioritized feeders with the highest outage impact relative to the overhead line miles. By targeting these higher-value feeders, the method focuses resources on the specific assets where the reliability gains per undergrounded mile are most significant. While the linear relationship provides a high-level physical justification, it fails to account for the diminishing returns of undergrounding in areas where outages are driven by equipment failure or lightning rather than trees and wind.

Figure 29: Relationship between Overhead Line Miles and Customer Minutes Out for Feeders in Xcel's Service Territory.



I.2. Xcel's "Indication of Benefits"

The Company conducts two hypothetical studies to illustrate the benefits of the targeted undergrounding plan—see Table 11. The first study (Scenario 1) examines 49 feeders and suggests that the plan would avoid 10.5 million Customer Minutes Out (CMO) each year. The Scenario 1 analysis indicates a total annual customer benefit of over $31.9 million and a BCR of 1.5. The second study (Scenario 2) assesses 13 feeders with high long-duration outage rates with a BCR of 0.6.

Table 10: Summary of Xcel's 'Indication of Benefits' Scenario Analysis

Metric	Scenario 1 (Top 49 Feeders)	Scenario 2 (High CELI-12 Feeders)
No. of Feeders Analyzed	49	13
Total Avoided CMO (Annual)	10.5 million	4.0 million
Average Length of Outage Events Avoided Per Year	23	12.5
Claimed Annual Benefit	$31.9 million	$12.0 million
Estimated Annual Revenue Requirement	$22.4 million	$19.9 million
Reported BCR	1.5	0.6

However, the Company clarifies that the analysis is an "Indication of Benefits" rather than a formal Cost-Benefit Analysis:

> [t]he Company characterized this analysis as an "Indication of Benefits," not a full Benefit Cost Analysis. This was one two hypothetical analysis scenarios the Company provided to illustrate the potential value of Targeted Undergrounding.
>
> […]
>
> It is important to emphasize that this analysis was illustrative only and not indicative of the methodology that will ultimately be used for Site Selection Criteria.[164]

As discussed in Section III.E – Value of Reliability, the economic model introduces the Interruption Cost Estimate (ICE) methodology developed by the Lawrence Berkeley National Laboratory, which converts reliability improvements into monetary benefits. The ICE methodology utilizes Minnesota-specific demographic data and reliability metrics to calculate state-level cost metrics, specifically the cost per customer event and the cost per CMO. The economic model relies on an ICE value of $3.05 for each minute of avoided interruption, which uses customer outage data from 2023 to 2025 that specifically targets areas prone to severe weather events and vegetation-related interruptions.

For its financial modeling, the Company also assumes a generic cost of approximately $1.5 million per mile for the conversion of these segments:

> Using the dollar per mile assumptions referenced in Docket No. E002/M-25-27—approximately $1.5 million per mile (or $31.7 million for 110,000 feet)—a total budget of $235 million could, hypothetically, underground all 154 overhead miles on the top 49 feeders identified in Docket No.

[164] Attachment B – DOC IR 47.

E002/M-24-27 as having the highest number of customer interruptions per overhead line mile.[165]

As shown in Table 3, benchmarking data from the US Department of Energy (DOE) shows that overhead-to-underground conversion costs vary significantly based on geographic complexity and utility jurisdiction. While Xcel's modeling relies on a flat assumption of $1.5 million per mile, external benchmarks for urban distribution conversion range from $2.88 million to as high as $12 million per mile in densely population or complex environments. Because the Company's targeting methodology specifically flags high-interruption segments—which often correlate with complex urban and suburban corridors—the reliance on a generic $1.5 million figure likely underestimates the actual capital requirements and, by extension, overstates the project's cost-effectiveness. The Department also notes that the CBA of overhead-to-underground conversion is heavily dependent on discount rates, undergrounding replacement cost, overhead T&D lifespan, value of lost load, reliability impact from undergrounding, and customers per line mile (population density).[166]

Table 8: DOE Table 2 – Examples of overhead-to-underground conversion costs.[167]

Utility (organization)	Investment Type	Period	Cost
Edison Electric Institute	Urban, Rural, and Suburban Transmission	2013	$0.54 - $12 million/mile urban (2013 USD); $1.1 - $11 million/mile rural (2013 USD); $1.1 - $6 million/mile suburban (2013 USD)
New Hampshire Electric Co-op	Urban and rural distribution	2009	$2.88 million/mile urban; $1.78 million/mile rural (2009 USD)
Pacific Gas & Electric	Urban and rural distribution	2023-2026	$2.97 million/mile (2019 USD)
Virginia Electric & Power Company	Rural distribution	2016-2022	$0.48 million/mile (nominal USD averaged over years)
Wisconsin Public Service Corporation	Rural distribution	2012-2021	$0.16 million/mile (nominal USD averaged over years)

Further, the Company omits O&M savings in the CBA, despite its statement that "ongoing operation costs of underground lines are significantly lower than overhead lines due to reduced needs for

[165] *Ibid.*
[166] *Resilient Power Grids: Strategically Undergrounding Powerlines*, U.S. Department of Energy Office of Electricity, (March 2022). At 15. Available at: Linkhttps://www.energy.gov/sites/default/files/2022-03/Undergrounding%20Powerlines%20Webinar%20Final%20PPT_508_0.pdf
[167] *Undergrounding Transmission and Distribution Lines: Resilience Investment Guide*, U.S. Department of Energy Grid Deployment Office (GDO) and UC Berkeley, (September 2024). At 5-6. Available at: (https://www.energy.gov/sites/default/files/2024-11/111524_Undergrounding_Transmission_and_Distribution_Lines.pdf

inspection, outage response and repairs."[168] Xcel claims that its hybrid design, which retains overhead service drops, "complicates estimation of resulting operational savings since a portion of the overhead facilities and their associated costs will remain," and thus "intends to incorporate estimates... in future analysis when more data is available."[169] For a proposal with a proposed capital expenditure of $233.7 million, these uncertainties must be resolved to provide a fair assessment of the net benefit to ratepayers, particularly as studies suggest that underground can save an average of $7,000 per mile per year in avoided vegetation management alone:

> Undergrounding saves $7,000 per mile per year on average in avoided vegetation management expenses.[170]

The Department recommends the Commission require Xcel to perform full BCA for all projects scheduled beyond the 2026 pilot phase, which must incorporate O&M savings (including avoided vegetation management and storm restoration costs), and use site-specific construction estimates and benefit calculations.

I.3. Treatment of Undepreciated Assets and Stranded Asset Risk

The treatment of undepreciated assets is a critical component of the justification of the project need. Xcel confirms that the revenue requirement for the Targeted Undergrounding program includes cost impacts associated with the retirement and removal of utility assets that have not been fully depreciated:

> […] the revenue requirement includes cost impacts associated with retirement and removal of utility assets that have not been fully depreciated.[171]

Therefore, ratepayers pay twice for the same reliability function: first for the remaining book value of the overhead poles and wires, and again for the $233.7 million in new underground infrastructure replacement. The Company does not provide an estimate of the total stranded asset cost that will be created by this program over the 2025-2030 period, nor does it evaluate whether accelerated depreciation or other regulatory mechanisms could mitigate this impact.

I.4. Review of Xcel's Consideration of Alternate Methods

The Company evaluates several alternative methods to address persistent reliability challenges, specifically overhead line rebuilds, enhanced vegetation management, and distribution automation technologies, such as FLISR (Fault Location, Isolation, and Service Restoration).

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[168] 2025 IDP – Chapter 2 at 15.
[169] *Ibid.*
[170] *Clear Skies Ahead: The Case for Undergrounding Utility Infrastructure*, Scenic America, (April 2019). At 4. Available at: https://www.scenic.org/wp-content/uploads/2024/02/ClearSkiesAhead82580.pdf
[171] Attachment B – DOC IR 47.

The Department reviewed Xcel's evaluation of alternatives to targeted undergrounding and finds several shortcomings. Xcel states that the other alternatives offer only "partial benefits" that "[f]all short of the comprehensive reliability and resilience improvements achievable through underground."[172] A primary concern is the oversight of lower-cost alternatives such as overhead line rebuilds and enhanced vegetation management. Xcel states that in a subset of cases, "backlot lines could be relocated to front lot overhead lines and obtain as much as 50 percent reductions in total outage durations,"[173] yet it favors undergrounding because rerouting "adds to construction costs and requires significant disruptions to customers' property."[174] However, the Company provides no quantitative cost-per-CMO comparison to demonstrate that undergrounding is more cost-effective. Furthermore, Xcel's evaluation of enhanced vegetation management is similarly limited; while the Company acknowledges it reduces risk, it labels the practice as "inherently reactive and cyclical" and notes it "currently does not have data to quantify the reliability benefits or duration of impact." The lacking review of alternative methods prevents a true least-cost comparison between the proposed targeted undergrounding proposal and other operational strategies.

I.5. Site Selection Criteria

Xcel proposes a phased, data-driven methodology to prioritize overhead distribution segments for underground conversion. In the initial phase, the program targets locations using Customers Experiencing Multiple Interruptions (CEMI) or Devices Experiencing Multiple Interruptions (DEMI) metrics, which trigger technical assessments that evaluate outage history, asset condition, and rear-lot access constraints. Xcel states that, as the program scales, the site selection prioritization will be informed by system-wide reliability metrics and operational data, including:

> SAIDI, SAIDI, and CELI analysis to identify segments contributing disproportionately to reliability indices, feeder-level ranking integrated with hardening and automation strategies, and predictive storm impact modeling to identify high-risk areas.[175]

The Department supports the phased approach as a pragmatic engineering strategy. By initially targeting localized, chronic outages before scaling up, the Company addresses immediate needs. However, the Department notes limitations regarding the economic optimization and transparency of the proposed site selection criteria. The site selection process misses opportunities to maximize cost-effectiveness. For instance, it does not require a hard quantification of alternatives, such as enhanced vegetation management or FLISR, to prove undergrounding is truly the optimal solution. Furthermore, the criteria fails to explicitly prioritize the replacement of fully depreciated assets. The retirement of functional equipment prematurely risks burdening ratepayers with avoidable stranded costs.

[172] 2025 IDP – Chapter 2 at 11.
[173] *Id.*, at 12.
[174] *Ibid.*
[175] 2025 IDP—Chapter 2 at 20.

To ensure prudent cost management and protect ratepayer interests, the Department recommends the Commission approve the site selection criteria with the following modifications:

- **Require Xcel to demonstrate a minimum BCR of 1.25, using tools like the ICE, to financially justify each individual project prior to approval.**
- **Limit or strictly prioritize undergrounding to sites where existing overhead infrastructure is fully depreciated to prevent stranded costs from premature retirements.**
- **Require the formal quantification of alternatives, specifically enhanced vegetation management, FLISR deployment, and backlot O&M expenses, during site selection to ensure undergrounding is the most economical choice.**

J. COST-BENEFIT ANALYSIS

The Department responds to the following notice topic:

> *Notice Topic 16.F: Feedback, Comments, and Recommendations on the proposed cost-benefit analysis for discretionary distribution system investments.*

The Commission required at Order points 11 and 12 of its 2023 IDP Order:

> Order point 11. In its next IDP, Xcel shall include a discussion of the results of stakeholder conversations about ways to conduct program-level cost-benefit analyses for relevant discretionary distribution expenditures.
>
> Order point 12. As part of the stakeholder effort on cost-benefit analyses, Xcel shall explain how it would define "discretionary" spending in this context and to explain its cost-benefit methodology, including specifically its identification of benefits.[176]

As required in Order point 11, Xcel provides a summary of stakeholder conversations about its definition of "discretionary," costs, benefits, and methodologies for its program-level cost-benefit analyses. [177] The initial workshop focused on stakeholder feedback, which included presentations on CBA categories and practices from both the Department and Fresh Energy.

In accordance with Order point 12, Xcel presents its definition of discretionary and cost-benefit methodology at its CBA workshops. In the context of a CBA, the Company defines discretionary as "optional investments by which not executing and spending the funds does not imminently endanger employees or the public from a safety or reliability incident on the system."[178] Xcel also provides a

[176] 2023 IDP Order – at 24.
[177] *Id.*, at Chapter 9, 12-13.
[178] 2025 IDP – Chapter 6 at 22.

summary of discussions on other utilities' approaches to CBAs and a brief overview of how the Company intends to conduct its analyses for the 2025 IDP at the second workshop.

In its 2025 IDP, Xcel provides an evaluation for two discretionary programs, End of Life Replacement (ELR) – Breakers and Grid Reinforcement. The evaluation includes an analysis of the financial and operational impact for each project. It also notes that its analyses for "Distribution System Programmatic spend is an evaluation that compares the total spend of the programs within the last 5 years (2020-2024) with the anticipated benefits of proactively investing in the distribution system."[179]

J.1. Calculation of Benefits

Xcel calculates benefits for its two programs based on three benefit categories. This section also covers how the benefit cost ratio (BCR) is calculated. The Department notes that descriptions for the calculation of benefits for Xcel's ELR and Grid Reinforcement programs appear to be the same, so the Department just explains the calculation ELR benefit categories, which covers both programs.

J.1.1. Overload Outages

Xcel explains how it calculates the benefit of reduced overload outages:

> Overload Outages (Customer Minutes Out) - The analysis looked at the age of the components and estimated the amount of customer minutes out (CMO) resulting from an overload-related outage if the Company had forgone the capital investment. We identified the locations of the capital spend within the program. We then pulled in five-year historical outage data by location within our Minnesota distribution system. From there, we estimated the amount of overload CMOs and the customer impact cost for the next five years if the Company had forgone investment based upon the age of the components and the historical outage rates for overloads within Minnesota. The customer impact cost was established using the Interruption Cost Estimator (ICE) Calculator 2.0. The total customer impact cost of the overload CMOs were then compared to the capital investment.[180]

This benefit is based on reduced overload outages. As opposed to reduced equipment outages due to failure from age or condition, this benefit is based solely on equipment overloads. **[TRADE SECRET DATA HAS BEEN EXCISED]** The Department finds the calculation of this benefit reasonable.

[179] *Ibid*.
[180] 2025 IDP – Chapter 6 at 22-23.

J.1.2. Equipment Outages

Xcel explains how it calculates the benefit of reduced overload outages:

> Equipment Outages (Customer Minutes Out) - The analysis took two methods into consideration to estimate equipment-related outages at the associated locations of the programmatic capital investment. First, we looked at the age of the components and estimated the amount of equipment-related CMOs if the Company had forgone the capital investment. We identified the locations of the capital spend within the program. We then pulled in five-year historical equipment outage data by location within our Minnesota distribution system. From there, we estimated the amount of equipment-related CMOs and the customer impact cost for the next five years if the Company had forgone investment based upon the age of the components and the historical outage rates for substation equipment outages within Minnesota. The total customer impact cost of the estimated substation CMOs were then compared to the capital investment. This initial methodology was then compared to the second method used to determine estimated equipment outages. We pulled five-year historical equipment outage data to determine the percentage of substation related outages as part of the total outages for each location within the Company's Minnesota distribution system. Quartiles were created based upon the level of substation outages as part of total outages with an associated outage growth rate for each percentile. The locations where ELR – Breaker work was done were then categorized by percentile to determine the estimated substation outage rate for the next five years if the capital investment had been forgone. These estimated CMOs were then averaged, and we applied a customer impact cost for the state of Minnesota to determine the dollar value of the estimated outages saved.[181]

The Department does not review this methodology in totality for its reasonableness, but does note that **[TRADE SECRET DATA HAS BEEN EXCISED]**

J.1.3. Proactive vs. Emergent Capital Work

Xcel explains how it calculates the benefit of Proactive vs. Emergent Capital Work:

> The analysis looked at the five-year historical spend of the program and isolated the labor components of the programmatic spend. We then applied a 1.5x escalator to the labor expenses as an estimate for

[181] 2025 IDP – Chapter 6 at 23-24.

> potentially emergent work if NSPM had forgone proactive capital investment. This cost escalator value was determined as a high-level estimate for the cost increase in emergent work due to labor rate changes for emergent work. This is due to the requirement for immediate remediation for customer outages that require potentially higher rates of labor and costs.[182]

This benefit category assumes that outages are more expensive to repair than upgrades that can be scheduled. The Department does not review this methodology in totality for its reasonableness, but does note that Xcel should base its 1.5x escalator on actual costs, rather than a high-level estimate.

J.1.4. O&M Costs

[TRADE SECRET DATA HAS BEEN EXCISED]

J.1.5. Undepreciated Asset Costs

[TRADE SECRET DATA HAS BEEN EXCISED]

J.1.6. Discounting of Benefits

[TRADE SECRET DATA HAS BEEN EXCISED]

J.2. End of Life Replacement– Breakers

[TRADE SECRET DATA HAS BEEN EXCISED]

The Department concludes that the End of Life Replacement– Breakers Program is not cost effective.

J.3. Grid Reinforcement

[TRADE SECRET DATA HAS BEEN EXCISED]

The Department concludes that the Grid Reinforcement Program is not cost effective.

K. GRID MODERNIZATION

The Department addresses two grid modernization projects that Xcel discusses in its IDP. The first project is the deployment of DERMS, and the second project is the Company's deployment of FLISR.

[182] 2025 IDP – Chapter 6 at 23.

K.1. Distributed Energy Resource Management System

The Department responds to the following notice topic:

> *Notice Topic 16.H: Feedback, Comments, and Recommendations on the distributed energy resource management system (DERMS).*

Xcel defines three separate types of DERMS. The first two, Grid DERMS and Aggregator DERMS, are defined by Xcel as follows:

> **Grid DERMS:** Primarily manages front-of-the-meter resources and serves as the DER monitoring, control, and coordination application as an extension to the existing Advanced Distribution Management System (ADMS). It maintains the as operated network model used in grid operations and supporting applications and ensures that DER operations stay within distribution grid limits.
>
> **Aggregator DERMS:** Primarily behind-the-meter resources, such as solar arrays and demand response assets. It also could facilitate control of these resources in coordination with the market and Distributed Energy Resource Aggregators (DERA). It is important to note that unlike Grid DERMS, Aggregator DERMS does not have situational awareness of the grid conditions.[183]

Xcel identifies a third DERMS, called an Enterprise DERMS, which is a combination of a Grid DERMS and Aggregator DERMS. Importantly, because Aggregator DERMS does not have situational awareness, the potential benefit of utilizing Aggregator DERMS for localized distribution grid management may be unrealized until an Enterprise DERMS is in place.

The Department is interested in DERMS because of its potential to offer enhanced demand response, with benefits catered for the distribution system. With a full DERMS deployment, Xcel could deploy demand response programs at the feeder level to avoid distribution upgrades, which has the potential to significantly lower overall distribution costs for all Xcel customers.

Xcel proposed implementing a limited Grid DERMS in its Capacity*Connect, a Distributed Capacity Procurement (DCP) proposal, filed with the Commission in 2025.[184] In the Capacity*Connect filing, the Company states that the DERMS technology is still under-development and as a result, all the functionalities will evolve with project learnings. For the proposed DCP phase, the Company states that it will "utilize a limited Grid DERMS deployment to monitor and/or dispatch the BESS for bulk system

[183] 2025 IDP – Chapter 11 at 2.
[184] *In the Matter of Northern States Power Company, dba Xcel Energy, Petition for Approval of Capacity*Connect, a Distributed Capacity Procurement (DCP) program*, Xcel Energy, Petition, October 3, 2025, Docket No. E002/M-25-378, (eDockets) 202510-223594-01, (hereinafter "Capacity*Connect" or "C*C" or "DCP").

use cases (e.g., MISO energy and capacity market participation) in close coordination amongst our distribution and commercial operations team.[185] In its initial comments, the Department recommended approval of the Grid DERMS implementation, but raised several concerns regarding the proposed implementation of Grid DERMS for the DCP project:

> The primary concern is that the current version of DERMS, if designed as a 'closed' or proprietary system, could become a significant technical barrier to entry. The closed DERMS design could effectively prevent third-party FTM resources or aggregators from participating in future distribution level service markets. Even if the Company does not plan to allow third-party aggregation in this Phase, the technology being deployed must not be allowed to preclude this possibility in the future. The architecture of this system must not create a monopoly for the Company over all future FTM distributed capacity services of this nature.
>
> Therefore, the Department's approval is contingent on ensuring this platform is built for future interoperability. This system must be technically capable of integrating with and managing third-party FTM assets and VPPs, not just the Company's own resources. This contingency ensures the investment in DERMS today serves as true platform for innovation, rather than a technical barrier to a competitive market.[186]

DERMS would also enable Xcel to deploy flexible load and generation programs that provide grid stability and significantly reduce interconnection or upgrade costs for participating customers. By enabling peak shaving, DERMS holds the potential to increase grid asset utilization, which therefore puts downward pressure on rates. Most importantly, the Department expects Xcel to incorporate localized grid benefits into either the Company's standard capacity planning forecasts or into its NWA process. However, based on Xcel's presentation in Chapter 11, it is unclear to the Department whether Xcel intends incorporate local distribution benefits into the Company's capacity and/or NWA processes.

The Department requests that Xcel explain in reply comments if and how Xcel intends to incorporate localized grid benefits from DERMS into its standard load and DER hosting capacity planning assumptions and non-wires alternatives processes.

As of today, Xcel explains in its response to IR 97 that the Company does not currently have the capabilities to systematically deploy its demand response programs for localized grid benefits:

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[185] *Id.*, at 27.

[186] *In the Matter of Northern States Power Company, dba Xcel Energy, Petition for Approval of Capacity*Connect, a Distributed Capacity Procurement (DCP) program*, Minnesota Department of Commerce, Initial Comments, December 19, 2025, Docket No. E002/M-25-378, (eDockets) 202512-225735-02

> Many of the Company's demand response programs *can* be deployed at a local level, either at a specific substation or an individual feeder—but this is not standard practice. While some programs can only be targeted at the substation level and others offer feeder level control, implementing local dispatch is a highly manual process that requires significant set up time and additional effort to restore normal configurations afterward. Program-specific rules and constraints must also be managed separately for these targeted events.
>
> It is also important to note that the Company's existing demand response programs were primarily designed as tools to support bulk system reliability, not localized grid needs. Shifting a program's use toward more local and targeted deployment would require the Company to evaluate customer agreements and contractual obligations to ensure compliance with established program terms.[187]

Xcel currently plans a limited deployment of its Aggregator DERMS in 2026. Xcel states:

> In 2026, the Company will continue with the phased transition of operationalizing additional customer programs in Colorado on the Aggregator DERMS platform. Plans also include initiating the transition of programs in Minnesota to the Aggregator DERMS platform.[188]

Unfortunately, Xcel does not list potential localized distribution grid benefits in Chapter 11, or in its response to IR 57 about potential cost savings of DERMS, which mainly identifies operational cost savings and customer cost savings as the main benefits of DERMS.[189] Xcel's main reference to localized distribution grid benefits states that the Aggregator DERMS:

> [W]ill support various models, including utility-led, aggregator-driven, hybrid, and dynamic pricing approaches, to optimize DER value across generation, transmission, and distribution systems.[190]

Given the importance of potential localized grid benefits derived from DERMS and Xcel's lack of pursuit of these benefits, it is critical for Xcel to begin exploring the deployment of its Aggregator DERMS for localized grid benefits before a wide-scale rollout of a program, consistent with Xcel's "walk-jog-run" approach. With the transition of its Minnesota programs to its Aggregator DERMS, Xcel can begin to pilot localized demand response programs with its Aggregator DERMS. A potential program could select one or more feeders to sign up customers for a new demand response program that curtails assets for system-wide and localized grid benefits. With limited deployment, Xcel could manually track

[187] Attachment B – DOC IR 97.
[188] 2025 IDP – Chapter 11 at 5.
[189] Attachment B – DOC IR 57.
[190] 2025 IDP – Chapter 11 at 14.

distribution grid benefits during Aggregator DERMS deployment at the feeder or substation level without an enterprise DERMS. The program needs to offer enhanced incentives for potentially increased levels of curtailment and test different incentive levels to ascertain the optimal incentive level in a fully-fledged program that deploys localized demand response to defer distribution grid upgrades. It is important that Xcel begin a pilot in this IDP to provide direction in its next IDP for essential Enterprise DERMS solutions.

The Department recommends the Commission order Xcel to begin a pilot program to test localized distribution grid benefits from its Aggregator Distributed Energy Resource Management System. At minimum the pilot should:

- **A. Test different incentive levels to determine the optimal incentive structure;**
- **B. Test at least two controllable load types; and**
- **C. Provide a cost-benefit analysis of localized distribution grid benefits compared to standard distribution grid upgrades.**

While the Department is interested in the potential benefits of DERMS, the Department is also concerned about the cost. The Department's two primary cost concerns are A) interoperability, and B) competitive bidding. To address the Department's first concern, Xcel explains three potential procurement pathways: Vendor Dependent, Phased Parallel Path, and Consolidated Single Vendor.[191] The pathways range from having separate vendors for potentially every program (i.e. thermostats, water heaters, electric vehicles, home batteries, solar, etc.) to having a single vendor provide every program. Xcel chooses the middle pathway, the Phased Parallel Path, which could have a single vendor for its Grid DERMS program and a single vendor for its Aggregator DERMS program, however single vendors are not required. The main risk of the Phased Parallel Path is interoperability. To have a fully integrated Enterprise DERMS, Xcel will either need an Enterprise DERMS that is interoperable with many Grid DERMS and Aggregator DERMS platforms, or Xcel will need to abandon one or more DERMS platforms and begin a whole new DERMS deployment.

Xcel claims that the Consolidated Single Vendor Approach, which would only use one vendor for all DERMS would have "longer timelines for implementation and substantially higher costs."[192] However, when the Department asked for evidence to support this statement, Xcel states:

> The substantially higher costs for a single vendor approach are based on the Company's experience and findings from its RFI process. As noted in the Company's response to DOC IR No. 54, the Company conducted an RFI and determined that no single vendor could meet all requirements for both Aggregator DERMS and Grid DERMS. This is because Grid DERMS solutions are typically offered by technology vendors with an established Advanced Distribution Management System (ADMS) product, whereas

[191] *Id*., at Chapter 11, 9. See Table 11-1.
[192] *Id*., at Chapter 11, 8.

> Aggregator DERMS solutions are generally provided by vendors that have an established Demand Response Management System (DRMS) product.
>
> Selecting a single vendor would require that vendor to develop the missing capabilities outside its core competency, resulting in significant customization, increased development costs, and higher integration expenses. These factors drive the expectation of substantially higher costs compared to the phased parallel approach.[193]

The Department finds Xcel's explanation reasonable, as legacy ADMS and DRMS vendors provide specialized products that stem from historical offerings. The Department clarifies that the referenced higher costs described by Xcel are relative to the comparative costs of an Aggregator DERMS or Grid DERMS vendor offering a non-existent product compared to an established vendor that only offers the missing product. Based on this assessment, the Department concludes that a Consolidated Single Vendor Approach is not reasonable.

Given that a full Enterprise DERMS solution is not currently available, the next best option is to pursue a single platform for the Aggregator DERMS and a single platform for the Grid DERMS. This strategy appears to align with Xcel's Phased Parallel Path. The Company states that the Phase Parallel Path "is also a focused and agile method that starts with a minimum viable product that builds capabilities over time." Should this statement confirm that Xcel intends to build off a single platform for its Aggregator DERMS and a single platform for its Grid DERMS, the Department accepts that this procurement strategy is the optimal implementation at this time. However, the Department seeks clarification to ensure that its interpretation is accurate.

The Department requests that Xcel explain in reply comments if the Company intends to contract with a single vendor for each of its Aggregator DERMS and Grid DERMS solutions, such that a total of two vendors will provide all planned DERMS services, or whether Xcel intends to contract with other DERMS vendors.

With Xcel's approach, there is still the potential for Xcel to abandon one or both DERMS platforms to pursue a unified Enterprise DERMS in the future. Abandonment could entail significant infrastructure, software, and staffing costs, for which the Department seeks to avoid. However, at this time, provided Xcel seeks contracts with only two DERMS vendors, the Department approves Xcel's DERMS procurement strategy.

Second, the Department reviews Xcel's efforts to ensure cost competitiveness of its DERMS. In IR 54, the Department asked Xcel to explain if Xcel used competitive bidding to select contractors for its Aggregator DERMS and Grid DERMS platforms.[194] IR 54 explains that the Company invited thirty-two vendors to participate in a request for information (RFI) for its Aggregator DERMS, and seven of these

[193] Attachment B – DOC IR 55.
[194] Attachment B – DOC IR 54.

vendors were invited to participate in a request for proposals (RFP) on April 30th, 2024. The Company held an RFI for its Grid DERMS in 2022, and includes a trade secret response that the Department does not attach to these comments for brevity. Upon review of IR 54, the Department is satisfied that Xcel has engaged in the necessary due diligence to ensure that its procurement of DERMS solutions is done so cost-effectively.

Finally, the Department asked Xcel to provide an estimate of the full-scale deployment costs for its Grid DERMS and Aggregator DERMS in IRs 58 and 59, respectively. Xcel declines to provide a cost estimate beyond its "limited Grid DERMS deployment," and cites the current estimate of $2.9 million, which the Company proposed for the DCP petition.[195] The Company similarly does not provide a full-scale deployment cost for its Aggregator DERMS system, and estimates a cost of $4 - $6 million to support its existing demand response programs.[196] While these initial estimates are modest, there exists the potential for significantly higher and ongoing licensing costs that could make these products significantly more expensive.

This section demonstrates that both the potential quantitative benefits and costs of DERMS remain mostly unknown by Xcel. The Department is cognizant that DERMS deployment is an ongoing process, however, Xcel should be required to provide a quantitative analysis of the net benefits of its DERMS deployment. While the Department expects significant potential benefits from DERMS, these benefits remain hypothetical, and warrant further investigation to ensure that DERMS is actually beneficial for ratepayers. As a grid modernization investment, Xcel must comply with IDP Filing Requirement D.2.k, which states:

> For each grid modernization project in its 5-year Action Plan, Xcel should provide a cost-benefit analysis based on the best information it has at the time and include a discussion of non-quantifiable benefits. Xcel shall provide all information used to support its analysis.[197]

The Department recommends the Commission order Xcel to provide a cost benefit analysis for all planned use cases of Aggregator DERMS, Grid DERMS, and Enterprise DERMS between 2027 and 2032 in Xcel's next IDP.

K.2. Fault Location Isolation and Service Restoration

The Department responds to the following notice topic:

> *Notice Topic 17: Other Areas of Xcel's IDP Not Listed Above, Along with Any Other Issues or Concerns Related to This Matter.*

[195] Attachment B – DOC IR 58.
[196] Attachment B – DOC IR 59.
[197] Notice – at 9.

Fault Location Isolation and Service Restoration (FLISR) is a grid modernization technology that uses automatic switching to quickly restore power to sections of the distribution grid that can safely re-energize without affecting service restoration where the outage occurs. Due to FLISR's quick service restoration, reliability metrics significantly increase when FLISR is activated, compared to standard outage restoration times. Xcel's initial deployment of FLISR was approved with the Commission's July 17, 2023 Order in Docket No. E002/GR-21-630. Xcel also states that it requested additional cost recovery for FLISR in its current rate case in Docket No. E002/GR-24-320.[198]

Through 2024, Xcel reports that it spent $12,227,659 on 226 FLSIR installations, which cover 118 circuits that correspond to Attachment L – Circuit Table in Docket No. E002/M-25-27, which is Xcel's Annual Safety, Reliability, and Service Quality Report.[199] These installations cover 11.9% of all circuits reported in Attachment L, although multiple FLISR installations can occur on the same circuit. With FLISR activations reported from January 1, 2025 to November 5, 2025, Xcel reports 30 FLISR activations, which are estimated to have saved 2,843,298 CMOs, valued at $8,672,059 in monetized reliability benefits using Xcel's $3.05 / CMO value. This value annualizes to 3,358,490 CMOs, and is estimated at $10,243,395, which is nearly equal to the capital expenditure for all FLISR installations in one year of operation alone. Xcel plans an additional $41.2 million to install FLISR between 2025-2027,[200] which could save an additional 11,300,000 CMOs annually, or $34.5 million of monetized reliability benefits.

The Department cautions that any general conclusions about the data presented cannot be made at this time due to the less than one year of data that Xcel provides in IR 49. Estimated reductions in CMOs will vary between years and by location, which makes a longitudinal study of FLISR benefits important. In addition, in IR 49, the Department requested data that would allow the Department to validate Xcel's CMO savings claims through the request of a single list of data that tracks individual FLSIR installations and circuit performance by year. The data Xcel provides in IR 49 is incomplete and reports the "Feeder" in Attachment D, and the "Xcel Circuit ID" in Attachment A, which corresponds to Attachment L – Circuit Table in Docket No. E002/M-25-27. This data inconsistency between Circuit IDs and Feeder IDs means that the Department cannot examine the performance of individual FLISR installations, or correlate that performance with spending or general reliability metrics on the Xcel circuits reported by Xcel in Attachment L – Circuit Table in Docket No. E002/M-25-27. The Department did not have sufficient time to request a second round of IRs to obtain the requested dataset, and therefore recommends that Xcel provide FLISR performance and spending data in its next IDP.

The Department recommends the Commission order Xcel to include data on all individual FLISR installations in a single dataset, which reports on the Xcel Circuit ID, installation year, installation cost, and reliability savings, consistent with data reported in Attachment D of IR 49 in its next IDP.

[198] 2025 IDP – Chapter 5 at 16.
[199] Attachment B – DOC IR 49, Attachment B. Note that Attachment B is not included in these comments, but can be provided upon request.
[200] 2025 IDP – Chapter 5 at 18. See Table 5-6.

L. PLANNED NET LOAD

The Department responds to the following notice topic:

> *Notice Topic 16.D: Feedback, Comments, and Recommendations on the updated Planned Net Load (PNL) methodology and risk analysis results.*

In the 2025 IDP, Xcel implemented a Planned Net Loading (PNL) methodology, an approach designed to quantify the dependable contribution of non-dispatchable DER on peak loads for feeders and substation transformers. The PNL methodology calculates a demand value between native loading (demand excluding all DER generation) and net loading (demand including 100% of DER generation). given by the following equation:

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

Where,

DF_{PV} = Dependability Factor of PV = 15%

By utilizing a DF_{PV}, Xcel can calculate a planning value that acknowledges the contribution of solar without compromising grid reliability. The DF_{PV} is a discounter for nameplate AC capacity that Xcel assumes will always be available during the solar generation window. Native loading assumes that Xcel cannot depend on any DER to lower peak demand; for example, due to the DER being non-dispatchable and lower output due to weather. Net loading is the demand actually seen at the substation for feeders and substation transformers with DER impacts included and assumes Xcel can rely upon all of the historical output. By moving away from a binary choice between Native and Net Loading, the PNL formula establishes a middle-ground for system planning.

According to Xcel, the limitation of primarily using Net Loading is that the amount of DER available is dependent on a variety of factors. For example, solar may not be available due to clouds. To address the uncertainty in DER availability, Xcel developed the concept of PNL. For the initial development of PNL, Xcel considered only Community Solar Gardens (CSG) and rooftop solar. The application of DF_{PV} means PNL will always be between Native Loading and Net Loading—rather than the total nameplate capacity. The 15% DF_{PV} was derived from a conservative analysis of five years of Minnesota-specific CSG data from 2016-2021. The Company explains the conservative nature of this selection by stating, "averaging these three lowest months [December, January, and November] results in a value of 15.04 percent, leading to our initial DF_{PV} of 15 percent."[201] While the 15% DF_{PV} is conservative, the Department notes that Xcel's own data in Table 1-13 shows summer tracking solar output at 40.93% and fixed solar at 49.22% during peak hours.

[201] 2025 IDP – Chapter 1 at 87.

The Department requests that Xcel, in reply comments, provide a justification for the continued use of a flat 15% factor for the current IDP cycle when the data suggests a significantly higher DF_{PV} is warranted for those months.

In the 2025 IDP risk analysis, the use of PNL rather than native loading results in the identification of four fewer overloaded feeders or substation transformers (nodes over 100% loading). Under the N-0 analysis, the use of PNL identified 20 nodes loaded over 100%, compared to 24 notes that would have been identified using native loading alone, representing a reduction of 4 critical risks (a 17% reduction). Similarly, the number of nodes identified as heavily loaded (75-100%) dropped from 47 to 42 (an 11% reduction). The Company describes the practical implication of these results, noting that "there were four fewer overloaded feeders or substation transformers identified in the risk analysis process, and therefore four feeders or substation transformers with a slightly reduced need for a capacity mitigation."[202] These results demonstrate that while PNL does not change the loading profile for the vast majority of the system (nearly 1,500 nodes showed no change due to lack of DER or minimal impact),[203] it effectively targets and mitigates the perceived risk on feeders with significant solar penetration. The Department notes the potential disconnect between the PNL methodology and the final project prioritization as using the PNL methodology did not change risk scores enough to defer projects.

The Department requests Xcel provide, in its reply comments, a specific threshold in a risk score required to trigger a project deferral to ensure the PNL methodology is a functional planning tool.

Table 9: Xcel Table 1-14 Node Impacts from PNL

Percent Loading	Using Native Loading	Using PNL	Difference
Over 100%	24	20	4
75-100%	47	42	5
Under 75%	195	195	0

Despite the reduction in identified risks, the application of PNL has not yet resulted in the deferral of any planned capacity projects in this IDP cycle. The Company's evaluation of the nine nodes most significantly impacted by PNL reveals that the associated capital projects are driven by multiple factors beyond simple N-0 overloads, such as the need to increase hosting capacity for future DER interconnections. Specifically, the Company notes that, "while the PNL methodology changed the quantity and magnitude of N-0 risks observed on our distribution system, the associated capacity project risk scores did not change enough to defer any of the projects."[204] Xcel highlights a critical

[202] *Ibid.*
[203] *Id.,* at Chapter 1, 88-89. Xcel notes: "In addition to the nodes listed in Table 1-14, there were 996 nodes that included some level of distributed energy resources (DER) but showed no change in percent loading when analyzed using the PNL methodology. Additionally, 495 feeders had no installed DER and therefore not change in percent loading when analyzed using the PNL methodology."
[204] 2025 IDP – Chapter 1 at 89.

trade-off, stating that "[a]lthough deferring capacity investment may offer near-term cost benefits, it may also constrain long-term system flexibility and preparedness for DER adoption."[205]

Xcel pursues a "walk-jog-run" approach to refining the PNL methodology based on stakeholder feedback and evolving system needs. A key proposed refinement for the 2027 IDP is the transition to seasonal DF_{PV} values, one for summer and one for winter, which more accurately reflects the significant variation in solar output across the year. For example, tracking solar output reaches approximately 40.93% in July compared to only 11.78% in December, which suggests that the current year-round 15% factor is extremely conservative for summer peak planning. MISO currently uses a seasonal construct for capacity accreditation, which deals with similar capacity risks. Additionally, the Company has committed to "exploring additional refinements, such as multiple solar profiles in LoadSEER to reflect geographic differences and investigating solar shapes by type"[206] to further increase the precision of the PNL calculation. While the Department supports the "walk-jog-run" approach, the move to seasonal DF_{PV} is a necessary step to prevent over-building the grid for summer peaks.

The Department recommends that Xcel evaluate the feasibility of accelerating the implementation of seasonal DF_{PV} values before the 2027 IDP, given that the foundational data for these factors is already present in the current filing.

M. NON-WIRES ALTERNATIVES ANALYSIS

The Department responds to the following notice topic:

> *Notice Topic 16.G: Feedback, Comments, and Recommendations on Non-Wires Alternative Analysis.*

As a part of its NWA analysis, IDP Filing Requirement 3.E.1 requires Xcel to:

> provide a detailed discussion of all distribution system projects in the filing year and the subsequent 5 years that are anticipated to have a total cost of greater than $2 million. For any forthcoming project or project in the filing year, which cost $2 million or more, provide an analysis on how non-wires alternatives compare in terms of viability, price, and long-term value.[207]

Additionally, IDP Filing Requirement 3.E.2. requires Xcel to include:

- Project types that would lend themselves to non-traditional solutions (i.e. load relief or reliability)

[205] *Ibid.*
[206] *Id.,* at Chapter 1, 90.
[207] August 30, 2018 Order.

- A timeline that is needed to consider alternatives to any project types that would lend themselves to non-traditional solutions (allowing time for potential request for proposal, response, review, contracting and implementation)
- Cost threshold of any project type that would need to be met to have a non-traditional solution reviewed.
- A discussion of a proposed screening process to be used internally to determine that non-traditional alternatives are considered prior to distribution system investments are made.[208]

In response to the Department's IR 14, Xcel defines NWA as "the strategic deployment of distributed energy resources, flexible demands, communication, and controls, and/or the aggregation of technologies intended to cost-effectively defer or avoid the need for the traditional mitigation solutions."[209] Notably, the only type of alternative distribution system project considered by Xcel in its 2025 IDP includes the "targeted demand response (DR) to reduce load, followed by energy storage and/or solar generation to address any remaining deficiency."[210]

In its 2025 NWA analysis, Xcel reviews twelve projects, of which six were found to be technically feasible but not distinctly cost-beneficial. As a part of the analysis, Xcel also "noted that PNL is now integrated into that process and that we have a goal of pursuing at least one project through an RFP process."[211]

In line with the IDP filing requirements and in accordance with Commission Orders, the Department provides the following analysis on Xcel's NWA results.

M.1. Project Types

To address the requirement to report on project types, Xcel provides detail in three categories: mandated, asset health and reliability, and capacity. The first project type considered by the Company is mandated. Xcel states that "mandated projects require the Company to relocate infrastructure within public rights-of-way to accommodate public initiatives, such as road widenings or realignments."[212] However, due to the timeline required for a mandated project, Xcel would have less than one year to design, fund, and relocate infrastructure, which makes it impractical to implement as an NWA.[213]

Another project type that Xcel highlights is asset health and reliability. Xcel defines such projects as those "required to replace equipment that is reaching the end of life or has failed."[214] Though the Company considers this category to cover a range of resources and/or technologies, Xcel finds that

[208] *Ibid*.
[209] Attachment B – DOC IR 14.
[210] 2025 IDP – Chapter 8 at 3.
[211] *Id*., at Chapter 9, 23.
[212] *Id*., at Chapter 8, 23.
[213] *Id*., at Chapter 8, 24.
[214] *Ibid.*

asset health and reliability projects are not suitable for NWAs. Due to potential outages, such projects connect customers back up to the distribution grid rather than serve them through a permanent microgrid. [215]

The last project type highlighted by the Company is capacity. This type of project is the only category that Xcel identifies as a viable option for NWA projects. As indicated above, Xcel's approach is to only target "demand response to reduce load, followed by energy storage and/or solar generation to address any remaining deficiency."[216] While capacity projects may provide the most straight-forward solution, the Department believes that there are opportunities for Xcel to explore other types of projects.

In its 2025 IDP, Minnesota Power (MP) states:

> A non-wires solution may also be suitable to improve reliability by enhancing circuit backup capability in situations where large capital costs projects are needed to create external backup sources. In that case a non-wires solution like a BESS can provide backup power during unplanned outages until crews restore service.[217]

Moreover, MP includes in its 2025 IDP conditions under which NWA projects can be used to improve reliability.[218] In the Cloquet NWA solution, MP applies a FLISR analysis "to identify optimal locations for reclosers and sectionalizers to automate switching and limit customer exposure to feeder faults."[219] As MP provides an analysis and example of a reliability project, the utility demonstrates that NWAs can address more than capacity projects. Accordingly, the Department finds that Xcel's current framing of NWA capabilities is narrow and should consider reliability in addition to capacity for NWA opportunities.

The Department recommends that the Commission require Xcel to consider reliability projects in its Non-Wire Alternatives Analysis.

M.2. NWA Implementation Timeline

In response to IDP Requirement No.3.E.2, Xcel provides a broad description of its timeline to evaluate and implement most NWA solutions. Xcel considers a three-year timeline and if the Company receives no bids on a project the timeline allows for Xcel to move forward with a traditional project. Xcel also notes that recent increases in lead times for substation transformers, traditional projects involving

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[215] *Ibid.*
[216] *Id.*, at Chapter 8, 3.
[217] *In the Matter of Minnesota Power's 2025 Integrated Distribution Plan*, Minnesota Power, November 3, 2025, Docket No. E015/M-25-140, (eDockets) 202511-224624-01, at 70.
[218] *Id.*, at 71.
[219] *In the Matter of Minnesota Power's 2023 Integrated Distribution Plan*, Minnesota Power, October 16, 2023, Docket No. E015/M-23-258, (eDockets) 202310-19614-01, at 72.

these components require a minimum of four years to allow for a full NWA evaluation.[220] As Xcel moves forward with NWA projects, the Department anticipates that the Company will provide further insight into a detailed timeline.

M.3. Screening Process

Xcel also provides a discussion of its screening process used to determine the feasibility of potential NWA projects prior to when distribution system investments are made. Xcel identifies the following three phases as a part of its current planning process:[221]

Table 10: NWA Planning Process

Phase 1	Phase 2	Phase 3
Traditional mitigations are developed and submitted through the budget creation process.	Budgeted projects are evaluated using NWA filters and a screening tool. Projects that pass move to Phase 3.	Engineering and procurement begin. Projects are solicited, and bids undergo detailed screening. If bids are shown to be cost-beneficial, the project proceeds to final engineering, construction, and commissioning.

For the purposes of the NWA analysis, the Company focuses on Phase 2 of the planning process. As a part of this phase, Xcel outlines a multi-step screening process under which only projects that meet the minimum criteria below advance to the NWA analysis.

- Project Type: Capacity
- Timeline: Year 3+
- Project Cost: >$2 million
- Risk Type: Non-Network Substation and Non-Single Bank Substation
- Risk Size: Annual Hours at Risk < 5,840
- Risk Quantity: ≤5 Risks[222]

For each project that meets the screening criteria, Xcel analyzes the peak load curve of each affected feeder or transformer and uses LoadSEER to forecast load five years beyond the traditional project's in-service date. Xcel then applies targeted demand response to reduce peak load, followed by energy storage and/or solar generation, to address any remaining capacity deficiencies.[223] The Department asked the Company for additional information on its load control programs in IR 97, to which Xcel addresses demand response as used across its system. Although Xcel can deploy DR programs at a local

[220] 2025 IDP – Chapter 8 at 27.
[221] *Id*., at Chapter 8, 21.
[222] *Id*., at Chapter 8, 23.
[223] *Id*., at Chapter 8, 20-21.

level, existing DR programs "were primarily designed as tools to support bulk system reliability, not localized grid needs."[224] The Department therefore understands that Xcel's demand response program is systemwide and does not serve locational needs within its NWA projects.

In IR 81, the Department asked the Company to provide an explanation of why Xcel chose a deferral period of five years after the planned in-service date. In response, Xcel states that its original analysis considered a 10-year deferral window.

> However, doing so came at the cost of needing a larger NWA solution, since the NWA solution is sized to mitigate the risk for the entire deferral period. As the load forecast increases over time, a longer deferral period requires a larger NWA size to accommodate additional forecasted load growth. This frequently resulted in the NWA solutions becoming infeasibly large.[225]

Therefore, Xcel determined that a five-year period balances deferral benefits with the size and cost of an NWA capable of mitigating capacity risk for the full deferral period.[226]

M.4. NWA Results

Although Xcel reviewed twelve projects, the Company provides a summary of nine projects, of which five were identified as technically feasible. The Department requested in IR 84 that Xcel provide an explanation as to why the other three NWA projects were not included. In its response, the Company identified that the projects were disqualified during the screening process and therefore Xcel did not prepare detailed NWA results summaries.[227] The three projects reviewed by Xcel but not included in the original filing are found in Table 15.

Table 11: Excluded NWA Projects

Project	Technically Feasible	Reason
Install West Coon Rapids (WCR) Transformer	No	Under the N-1 condition, this transformer lacks a bus tie, meaning that an NWA solution would need to cover the entire transformer load for all 8,760 annual hours at risk.
Install Two 50 MVA TRs at Brooklyn Park	No	Under the N-1 condition, the available transferrable load eliminated any load risk thus no remaining capacity violation existed.
Install Lone Oak (LOK) TR3	Yes	Under the N-0 condition, the project was found below planning limits as the transformer was forecasted to

[224] Attachment B – DOC IR 97.
[225] Attachment B – DOC IR 81.
[226] *Ibid*.
[227] Attachment B – DOC IR 84.

		operate at 87% of its capacity rating, which does not trigger capacity driven investment.

Source: Xcel Energy's response to Department IR 84

The nine other NWA projects reviewed by Xcel are summarized in Table 16.

Table 12: NWA Candidate Projects[228]

Project	Technically Feasible	Incremental Net Impact	Traditional Project Cost
Install Stillwater Lake Elmo Area Substation	No	$-10,676,842	$18,100,000
Install Lindstrom Area Substation	No	$-479,1050	$13,700,000
Install Baytown BYT Feeders	No	$-343,540	$3,000,000
Reinforce Credit River CTR TR2	No	$2,340,4834	$5,200,000
Reinforce Lexington TR1 and TR2	Yes	$3,352,058	$7,400,000
Reinforce Parkers Lake Feeders	Yes	$1,876,812	$2,250,000
Reinforce Coon Creek CNC TR1 to 50 MVA	Yes	$2,130,901	$2,500,000
Reinforce Elm Creek TR1 to 50 MVA	Yes	$1,997,692	2,400,000
Install Osseo Oss TR3	Yes	$4,491,830	4,600,000

Xcel notes that the project cost estimates in Table 6 above are desktop estimates and that "any potential NWA project would require additional analysis to confirm true cost-effectiveness and technical feasibility."[229] The Company further explains that:

> while stacked values are considered for the NWA solution, our NWA analysis considers only the cost of the traditional project and no additional value associated with a traditional mitigation. Therefore, the analysis may show that an NWA solution has a positive incremental net impact, that result does not necessarily support a conclusion that the NWA is more beneficial than the traditional solution. [230]

[228] *Id*., at Chapter 8, 4.
[229] *Ibid.*
[230] *Id*., at Chapter 8, 34.

In its results, Xcel also provides an overview of the five feasible projects.[231] The two projects Xcel intends to go out to RFP are Reinforce Parkers Lake feeders and Reinforce Cook Creek CNC TR1 to 50 MVA as the projects have the possibility of being cost-beneficial, and require the smallest amount of incremental DER.[232]

M.5. Societal Discount Rate and WACC

In Order Point 5 of the Commission July 26, 2022 Order, Xcel is required to "use both the WACC and societal discount rate in its NWA analysis and discuss the results of the two approaches in a future IDP stakeholder meeting."[233] In its 2025 NWA analysis, Xcel provides both the weighted average cost of capital (WACC) and the societal discount rate for each feasible NWA project.[234] However, upon the application of WACC and the societal discount rate in its analysis, the Company notes that the approach "is imperfect and provides limited value in assessing which, if any, projects to move forward to a solicitation phase."[235] Xcel reports that for the 2025 NWA projects, the incremental net impact of the optimal solution under both discount rates differs less than $100,000 in many cases. The Department concludes that Xcel complies with the Order in its 2025 NWA analysis.

M.6. Improvements to NWA Analysis

Pursuant of IDP requirement 3.A.5.d, Xcel must also report on the improvement of its NWA analysis, which includes "market solicitations for deferral opportunities to make sure Xcel can take advantage of distributed energy resources to address discrete distribution system costs."[236]

Xcel highlights a key improvement in the inclusion of PNL methodology for assessing N-0 risks. In the application of the PNL methodology, Xcel is able "to more accurately account for the dependability of solar PV. By applying the PNL methodology, which applies an expected dependability factor to each solar PV, the NWA solutions become dependent on the solar operating as anticipated during peak conditions."[237] Analysis of the PNL methodology by the Department can be found in Section III.L.

Additionally, in accordance with Order point 26 of the 2023 IDP Order:

> Xcel shall conduct a Request for Information (RFI) process to assess the feasibility of its planned Non-Wires Alternatives solicitation, including the

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[231] *In the Matter of Xcel Energy's 2025 Integrated Distribution Plan*, *Second Errata*, Xcel, January 26, 2026, Docket No. E002/M-25-142, (eDockets) 202601-227389-01 (hereinafter "2025 IDP – Second Errata"). Note: Xcel provides corrections to its battery storage calculations for the feasible NWA projects.
[232] *Id.*, at Chapter 8, 18.
[233] July 26, 2022 Order – at 11.
[234] 2025 IDP – Chapter 8 at 40.
[235] *Ibid*.
[236] Notice – at 4.
[237] 2025 IDP – Chapter 8 at 38.

proposed "ARR split" compensation, and make a compliance filing reporting on the results of the RFI within 12 months of this order.[238]

The Department responded to Xcel's RFI on the feasibility of its planned NWA solicitation.[239] To gauge further interest, Xcel proposes to issue an RFP in the development of the two identified NWA projects. The Company provides the following timeline to summarize the solicitation.

Table 13: NWA RFP Timeline[240]

Step	Issue RFP	RFP Responses Due	Bid Review and Project Selection	RFP Report Submitted to the Commission
Target Date	No later than June 1, 2026	July 31, 2026	September 30, 2026	November 1, 2026

N. CERTIFICATION REQUEST

The Department responds to the following notice topics:

Notice Topic 11: Should the Commission approve, modify, or deny certification of the mobile battery system?

Notice Topic 12: Should the Commission approve, modify, or deny Xcel's request to streamline the certification process by requiring the following information to evaluate whether the proposed project serves the public interest:

a. A description of why the project is necessary for grid modernization;
b. A description of the project's objectives and potential benefits to customers;
c. A cost range for the project; and
d. The expected timing for project implementation.

Notice Topic 13: Are there any other issues or concerns related to this matter?

Xcel requests certification for a mobile battery system that would be used to expedite load interconnection requests before permanent infrastructure could be installed. The estimated 1MW/2MWh project cost is $6-7 million plus tax and overheads.[241] Xcel requests certification authority under Minn. Stat. § 216B.2425, subd. 3, which states:

[238] 2023 IDP Order– at 16.
[239] *In the Matter of Xcel Energy's 2023 Integrated Distribution Plan*, *Non-Wires Alternatives Request for Information*, Xcel Energy, January 6, 2025, Docket No. E-002/M-23-452, (eDockets) 202501-213594-01.
[240] 2025 IDP – Chapter 8, at 19.
[241] *Id.*, at Attachment F, 5-6.

> Commission approval.
>
> (a) By June 1 of each even-numbered year, the commission shall adopt a state transmission project list and shall certify, certify as modified, or deny certification of the transmission and distribution projects proposed under subdivision 2. Except as provided in paragraph (b), the commission may only certify a project that is a high-voltage transmission line as defined in section 216B.2421, subdivision 2, that the commission finds is:
>
> (1) necessary to maintain or enhance the reliability of electric service to Minnesota consumers;
>
> (2) needed, applying the criteria in section 216B.243, subdivision 3; and
>
> (3) in the public interest, taking into account electric energy system needs and economic, environmental, and social interests affected by the project.
>
> (b) The commission may certify a project proposed under subdivision 2, paragraph (e), only if the commission finds the proposed project is in the public interest.

If the certification request is approved, Xcel states:

> Within approximately three months of Commission certification, we intend to initiate the process to procure the battery and other equipment. After receiving the equipment, we expect it to take approximately 12 months to complete installation at the first site. We expect this entire process will take approximately 24-30 months from the certification decision. Deployment will follow interconnection and permitting processes, with coordination across Distribution Planning, Distributed Energy Resources (DER) Engineering, and Distribution Operations.
>
> […]
>
> Consistent with the applicable statutes and our past practice, if certified, we will seek cost recovery of the mobile battery costs in a forthcoming TCR petition. The statute governing the TCR, Minn. Stat. § 216B.16, subd. 7b, "allows [the Company] to recover costs associated with investments in distribution facilities to modernize the [Company's] grid that have been certified by the commission under section 216B.2425." The evidence provided in this IDP, demonstrates that the mobile battery is consistent

> with the public interest, warrants certification, and subsequent recovery through the TCR.[242] [citation omitted]

Therefore, should the Commission approve Xcel's certification request, Xcel will begin its procurement process and will seek cost recovery through the TCR. While there will be additional opportunity for prudency review in the TCR, the short comment process is best supported by thorough informational requirements that would be approved at the time of certification.

N.1. Certification Request

Xcel claims that its mobile battery project is in alignment with Minn. Stat. § 216B.2425, subd. 2(e).[243] Xcel states:

> The mobile battery supports grid modernization consistent with Minn. Stat. § 216B.2425, subd. 2(e)—which expressly references energy storage as a qualifying investment. Additionally, this mobile mattery will enhance reliability through temporary capacity relief, support of new or growing customer load, support demand response by reducing feeder peak, and delay the need for traditional infrastructure. These capabilities align with the statute's intent to modernize the distribution system through new technologies.[244]

As referenced above by Xcel, Minn. Stat. § 216B.2425, subd. 2(e), states:

> In addition to providing the information required under this subdivision, a utility operating under a multiyear rate plan approved by the commission under section 216B.16, subdivision 19, shall identify in its report investments that it considers necessary to modernize the transmission and distribution system by enhancing reliability, improving security against cyber and physical threats, and by increasing energy conservation opportunities by facilitating communication between the utility and its customers through the use of two-way meters, control technologies, energy storage and microgrids, technologies to enable demand response, and other innovative technologies.[245]

The Department agrees that energy storage is covered by Minn. Stat. § 216B.2425, subd. 2(e). The Department finds that the certification request is statutorily compliant, and devotes the rest of the discussion to the determination of whether the project is in the public interest, consistent with Minn. Stat. § 216B.2425, subd. 3(b).

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[242] 2025 IDP – Attachment F, 8-10.
[243] Minn. Stat. § 216B.2425, subd. 2(e) (2024).
[244] *Id.*, at Attachment F, 9.
[245] Minn. Stat. § 216B.2425, subd. 2(e) (2024).

N.2. Public Interest Determination

Xcel states that its mobile battery would primarily be used for the following purposes:

- New customer facilities under construction.
- Electrification of transportation, building heating, or industrial processes.
- Load increases that outpace traditional infrastructure construction timelines.[246]

Xcel elaborates that the first two bullets to add new load are the primary purpose of the battery:

> When new load requirements exceed existing capacity, we analyze various scenarios to temporarily serve new loads, including second-tier switching and serving a portion of the new load. However, this is not ideal when customers need all of their requested load in a shorter timeline than the full construction buildout would take. We are expecting that large electrification loads such as concentrated EV charging and all electric buildings may be such situations that would drive the need for a temporary solution such as the mobile battery.[247]

The Department is not convinced that a 1 MW/2 MWh battery is sized to the forecasted loads, for which Xcel fails to identify in its request. Peak hours typically run from 5 PM to 9 PM, and a 2-hour battery may only be able to serve the first two hours of the grid need. While electric vehicle charging may be covered with intermittent starts and stops during peak hour charging, building electrification and natural load growth may not be served by this load shape. Xcel makes a convincing argument in its Non-Wires Alternatives (NWA) section of its IDP about why so many of its potential NWA projects are not suitable for NWA because of their load shapes.[248] However in contrast to NWA, Xcel's potential mobile battery projects meet specific load shapes rather than aggregated loads throughout a feeder. Indeed, every battery project, except for one that Xcel presents in its NWA section, is sized with greater than two hours of storage.[249] Xcel's stated reason for its battery size is "[t]he mobile battery under consideration will be no larger than 1 MW / 2 MWh, which is the maximum size suitable for a trailer-mounted unit."[250] While Xcel states that it received approval in Colorado for a similar 1 MW / 2 MWh battery, it provides no evidence of the efficacy of the battery to meet the anticipated grid need;

[246] 2025 IDP – Attachment F at 8-10.
[247] *Id*., at Attachment F, 4.
[248] See 2025 IDP Chapter 8.
[249] 2025 IDP – Second Errata. See "Reinforce Lexington TR1 and TR2" Errata Table 8-2. Note: Xcel pairs the 8.27 MW battery solution with a large 47.6 MW solar array.
[250] 2025 IDP – Attachment F at 4.

however, unlike in Xcel's IDP certification request, the Colorado mobile battery does identify a potential project.[251]

Xcel does not address in its certification request the option for alternative demand response options, in particular flexible load interconnection. Flexible load interconnection could provide the same benefit of earlier energization while not requiring a significant capital investment. While flexible load interconnection may not be suitable for all applications, neither is Xcel's mobile battery.

As stated by Xcel, the primary beneficiaries are anticipated to be building electrification and electric vehicle customers, which are aligned with the State's energy goals. As a concept, the Department agrees that the idea of a mobile battery offers new options that can serve state energy goals; however, the lack of due diligence by Xcel to provide any meaningful analysis of the quantitative benefits of the mobile battery project does not provide sufficient evidence that the project is in the public interest. Based on Xcel's existing NWA screening process results, it seems unlikely that the mobile battery would deliver a cost-effective solution.

With the concerns noted by the Department in this section, the Department cannot conclude that Xcel's certification request is in the public interest. However, the Department can support Xcel's certification request with modifications to ensure that the project is deployed in a manner most consistent with the public interest. The Department outlines its modified recommendation in the next section.

N.3. Certification Reporting

If the Commission grants Xcel's certification request, Xcel states:

> [W]e may decide after we do further development of the project that it needs to change from our original concept, or we may no longer believe it is in our customers' best interests. In any case, we would return to the Commission to either provide an update on the status of the project or to request cost recovery. The Commission already has existing robust procedures to evaluate investments in cost recovery proceedings. It could, however, require the Company to provide specific information with its request for cost recovery, such as cost-benefit analyses, narrative discussion of qualitative customer benefits, and/or other information to ensure alignment with the certified project.[252]

Xcel proposes the following requirements to determine that the project is in the public interest, and is therefore eligible for cost recovery in a TCR cost recovery proceeding:

[251] *Id*., at Attachment F, 3.
[252] *Id*., at Attachment F, 10.

> To strike a balance between the Company's need for flexibility and innovation, and the Commission's need for transparency and accountability, we propose the following certification requirements to support the Commission's evaluation of whether the proposed project serves the public interest:
>
> 1. A description of why the project is necessary for grid modernization;
>
> 2. A description of the project, its scope, and its intended objectives;
>
> 3. A cost range for the project; and
>
> 4. The expected timing for project implementation.[253]

The Department notes that each of Xcel's certification requirements have already been addressed in Appendix F. Xcel would only need to provide an updated cost range and timing for the project to obtain approval for cost recovery. The Department understands these requirements to be the basis for which a final public interest determination will be made in the TCR, and thus if Xcel can meet the requirements, it is entitled to cost recovery.

With the noted concerns discussed in the previous section about the need for the battery itself, the Department can support a certification request with a modified cost recovery requirement. The modification rests on the simple assumption that Xcel proposes a new class of NWA project, which is for new customers. The use of the battery is the same as in the standard NWA process, except that the deferral period is estimated around one year, the battery can be re-used, and the battery is already owned by Xcel, and therefore does not need to be procured. While these requirements would necessitate some additional process modifications to include new customer projects as eligible for NWA, these requirements are achievable, and align well with Xcel's existing NWA cost-benefit analysis structure.

Under the Department's framework, Xcel would screen a list of new customer loads that require distribution upgrades to analyze if the mobile battery would deliver a lower cost compared to delay with standard distribution upgrades. Benefits could be assigned based on a comparison of only costs, which would compare mobile battery installation and decommissioning costs and the pro rata mobile battery capital costs to the distribution upgrade deferral benefit. Xcel could include other benefits such as avoided carbon emissions from EV charging or electrification, for example. While the benefit of earlier customer revenue may be theoretically eligible under an NWA framework, customer informational requirements to obtain annualized revenue projections will likely be infeasible to calculate.

Integration of the mobile battery project into Xcel's existing NWA process provides a post-hoc guarantee of cost-effectiveness analysis that places the burden of proof after the approval of

[253] *Id*., at Attachment F, 11.

certification. The NWA process ensures that Xcel will choose the most cost-effective application for its mobile battery project, and will provide the Commission and stakeholders with valuable information to determine if future mobile batteries, or other grid upgrade deferral measures could save ratepayers money.

It is important to view Xcel's mobile battery certification request in the greater context of load growth that Xcel predicts:

> Across all three scenarios, the forecast shows distribution system growth from approximately 8.5 GW today to between 9 and 10 GW by 2035. This projected increase of 0.5 to 1.5 GW over the next ten years is substantial. To put this into perspective, a 1 GW increase would require *at least* 10 new substations, 20 new substation transformers, and 150 new feeders to support the additional load. This level of infrastructure investment highlights the urgency and importance of proactive planning and flexible budgeting.[254]

As Xcel states above, the need to adapt to new customer load growth is both urgent and significant. Yet Xcel's existing NWA process does not address any of the load growth from new customers. With the mobile battery, and future flexible load interconnection—what Xcel refers to as Flexible Energization[255]—the creation of a new customer NWA process would support every IDP planning objective by maximizing customer value and grid utilization with new customer DER options. Every year of delay means that new customers will have to shoulder the potentially higher costs of standard grid upgrades, compared to, in particular, Flexible Energization, which requires no significant grid upgrades. Xcel is currently considering Flexible Energization with its Grid Distribution Energy Resource Management System (DERMS),[256] which would provide a second new customer interconnection option to the mobile battery system. With potentially overlapping timelines of Flexible Energization and the mobile battery system, the development of a new customer NWA process will provide a quick integration of Flexible Energization when the technology becomes available.

In light of these concerns, the Department offers two recommendations regarding the mobile battery certification request:

The Department recommends the Commission order Xcel to develop a new customer non-wires alternatives process that will screen projects and provide a cost-benefit analysis, consistent with Xcel's existing non-wires alternatives process, for new customer solutions that include energy storage and flexible energization.

[254] *Id*., at 7.
[255] *Id*., at Chapter 11, 13.
[256] *Ibid*.

The Department recommends the Commission certify Xcel's mobile battery request with the following certification requirements to support the Commission's evaluation of whether the proposed project serves the public interest:

- **A. A cost range for the project;**
- **B. The expected timing for project implementation; and**
- **C. The utilization of a new customer non-wires alternatives screening process and cost-benefit analysis framework that will be used to select all mobile battery sites.**

N.4. Other Concerns

Regarding Notice Topic 13, the Department has no other concerns about Xcel's mobile battery certification request.

O. PROACTIVE CAPACITY INVESTMENTS

The Department responds to the following notice topic:

> *Notice Topic 16.C: Feedback, Comments, and Recommendations on the proactive capacity investments.*

The Department submitted its Proactive Upgrade Initial Comments on January 28, 2026.[257] These comments cover the majority of discussion topics regarding proactive upgrades. In its comments, the Department expressed concerns regarding the need for proactive upgrades and expressed its preference for the Distribution System Reactive Upgrades Process (DSRUP),[258] which allocates pro rata costs of distribution upgrades to individual generation projects, such that no participant is responsible for the full upgrade cost.

There is no analog to the DSRUP for load. While the Department understands that contribution in aid of construction (CIAC) and estimated sales factor into upgrade cost payments, there is an opportunity for clusters of load projects to share upgrade costs that may either lower the individual cost burden to individual customers, and/or lower pro rata costs due to economies of scale. Even if there are no benefits to individual customers, it may still be cost beneficial to all ratepayers to avoid multiple distribution upgrades in the same area over several years. This process may also reduce Xcel's reliance on forecasting of new capacity additions at the feeder-level, which could de-risk Xcel's new capacity budgeting. Finally, certain projects may also create hosting capacity in generation-constrained areas, which would allow for cost sharing between load and generation and could lower costs for all parties.

[257] Department Initial Comments on Xcel's Proactive Upgrade Proposal.
[258] See Attachment A for the draft proposal. *In the Matter of Establishing Tariffs for Distribution System Cost Sharing for Interconnection in Constrained Areas*, *Notice of Comment Period*, September 26, 2025, Docket No. E002, E015, E017/CI-24-288, (eDockets) 20259-223328-01.

The Department recommends the Commission order the Executive Secretary to open a working group tasked with the development of updating the Distribution System Reactive Upgrades Process for load.

P. EQUITY ANALYSIS

Outages are another key driver of distribution investment and an important indicator of system condition and resilience. In response to IR 31, Xcel provided outage data for 2023 and 2024, **[TRADE SECRET DATA HAS BEEN EXCISED]**

Figure 30:

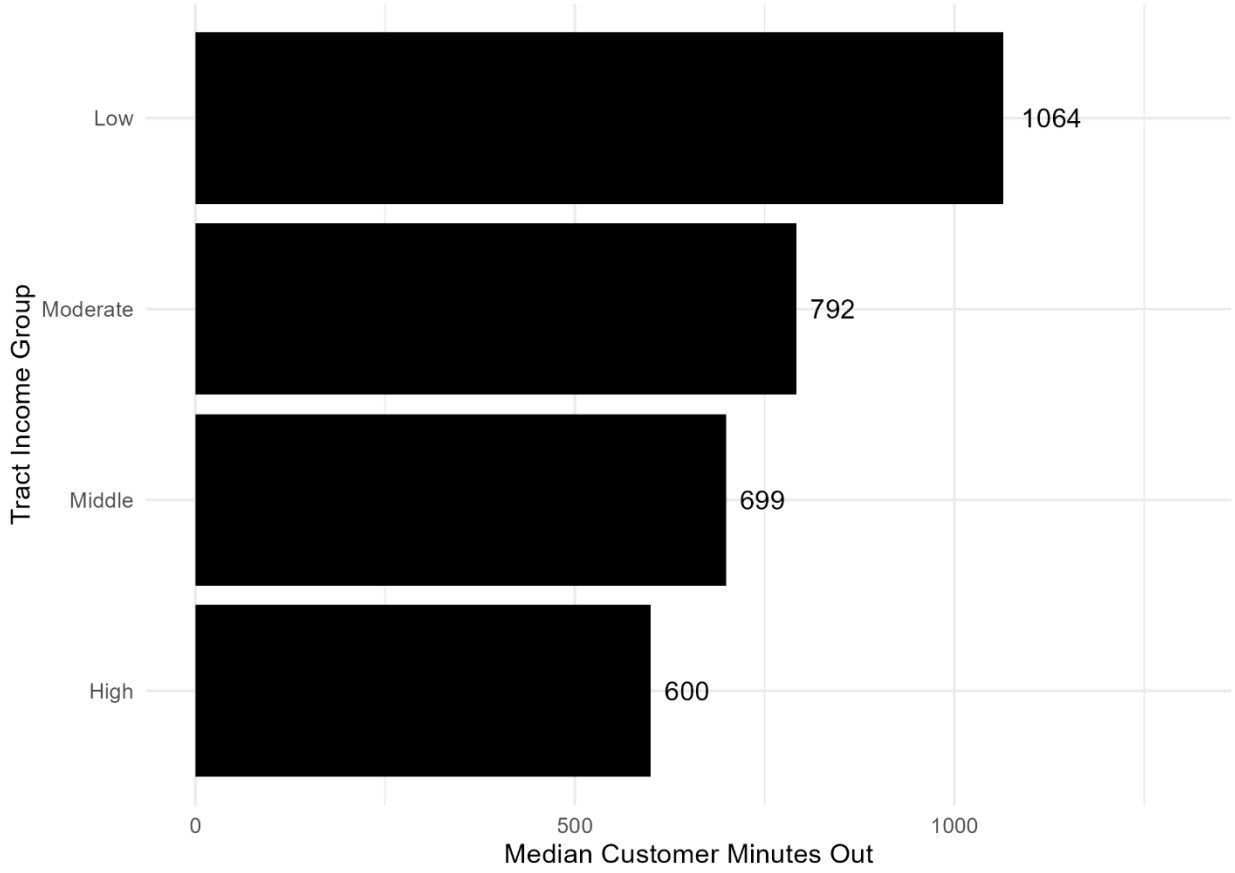
[TRADE SECRET DATA HAS BEEN EXCISED]

Using the geocoded data, the Department calculated median customer minutes out experienced by income group. For the purposes of this analysis, the Department used income group guidelines from the U.S. Federal Reserve[259] in order to group census tracts by their median income. Tracts were groups using the concept from the federal reserve, which defines groups as follows:

- Low-Income: Household Income under 50 percent of the area median income (state median income for households for the purposes of this analysis)
- Moderate-Income: Between 50 and 80 percent of the state median income.
- Middle-Income: Between 80 and 120 percent of the state median income.
- Upper-Income: More than 120 percent of the state median income.

[259] *Community Reinvestment Act*. Board of Governors of the Federal Reserve System, (2025). Available at: https://www.federalreserve.gov/consumerscommunities/cra_resources.htm

Figure 31: Median Customer Minutes Out by Income Group

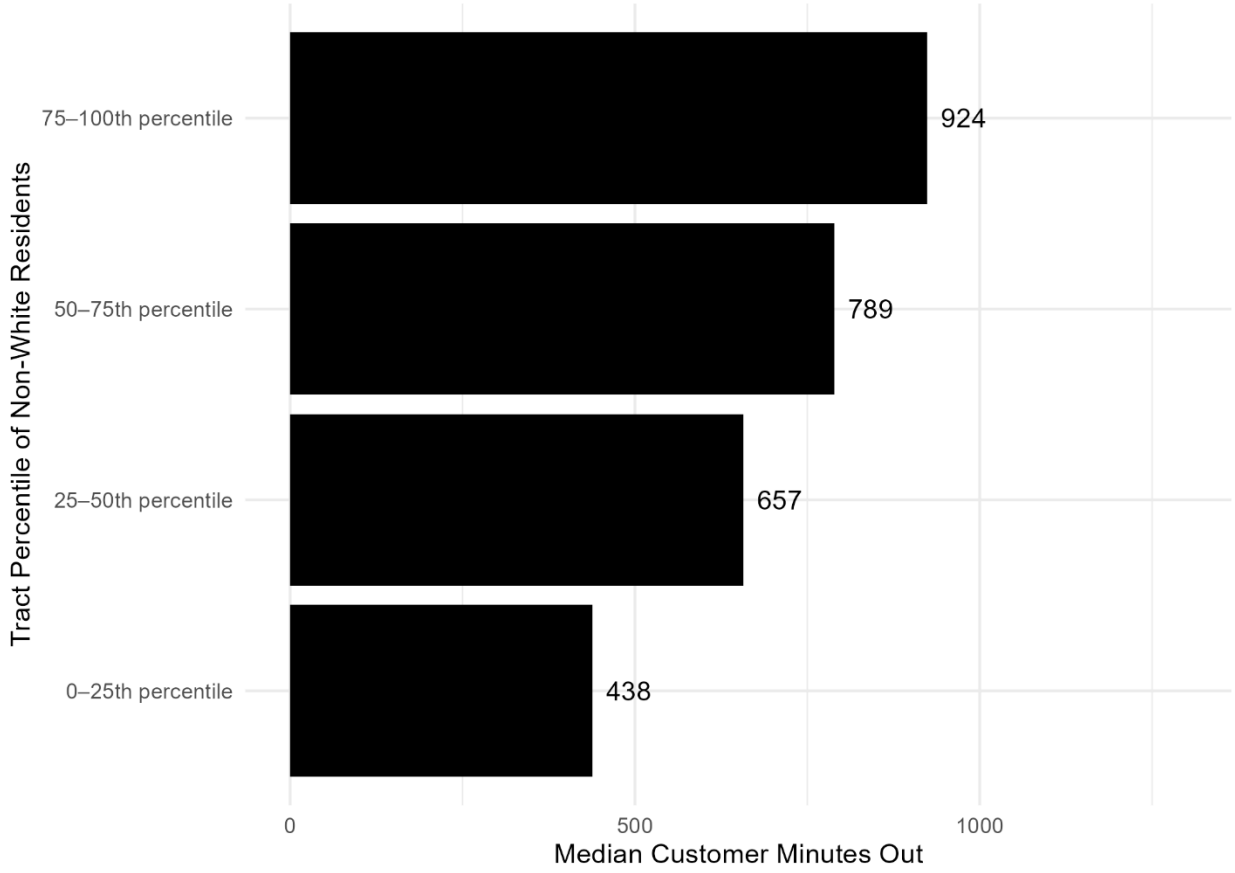


The figure above shows significant variation across income groups.

The Department requests Xcel explain in reply comments causes behind the variation of outages across income groups. Xcel should explain if there are alternative ways to look at the outage duration across income groups, and any should explain analyses Xcel has done on this topic.

The Department also grouped outages by the proportion of non-white residents in census tracts. The results are shown in Figure 32.

Figure 32: Median Customer Minutes Out by Proportion of Non-White Residents



Since these figures show systematic differences:

The Department requests Xcel explain in reply comments causes behind the variation in outages across census tracts with varying levels of non-white population. Xcel should explain if there are alternative ways to look at the of outage duration across racial groups, and should explain if any analyses Xcel has done related to incorporating equity considerations in reliability planning.

Q. DATA REQUESTS FOR GEOSPATIAL ANALYSIS

While the bulk of these comments address matters related to how Xcel develops its budget estimates, this section discusses where Xcel decides to spend money. Budget formation is fundamentally different from budget allocation, and a geospatial analysis of Xcel's spending can provide additional insight about the optimal allocation of budgets. However, to conduct this analysis, the Department requires additional data and approval from the Commission to conduct a geospatial analysis. The Department makes several data requests in this section, and presents a single request for Xcel to reply to at the end of this section.

In response to IR 6, Xcel provides a disaggregated breakdown of forecasted distribution spending by budget category and Planning Division for the period 2024–2030. Figure 33 breaks down the top two budget categories by planning division (PD), while Figure 34 presents total spending by PD, broken down by budget category.

Figure 33: Xcel Spending on Asset Health & Reliability and Capacity by Planning Division

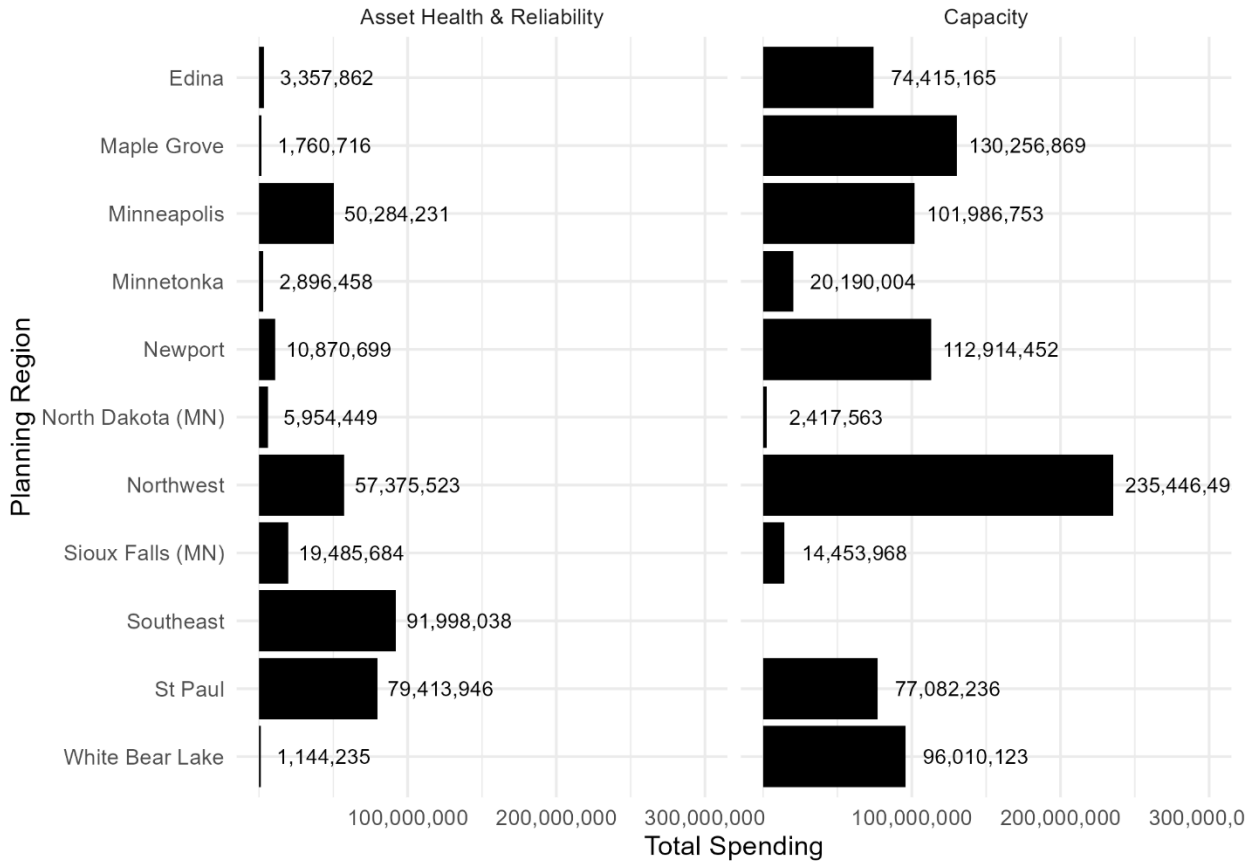
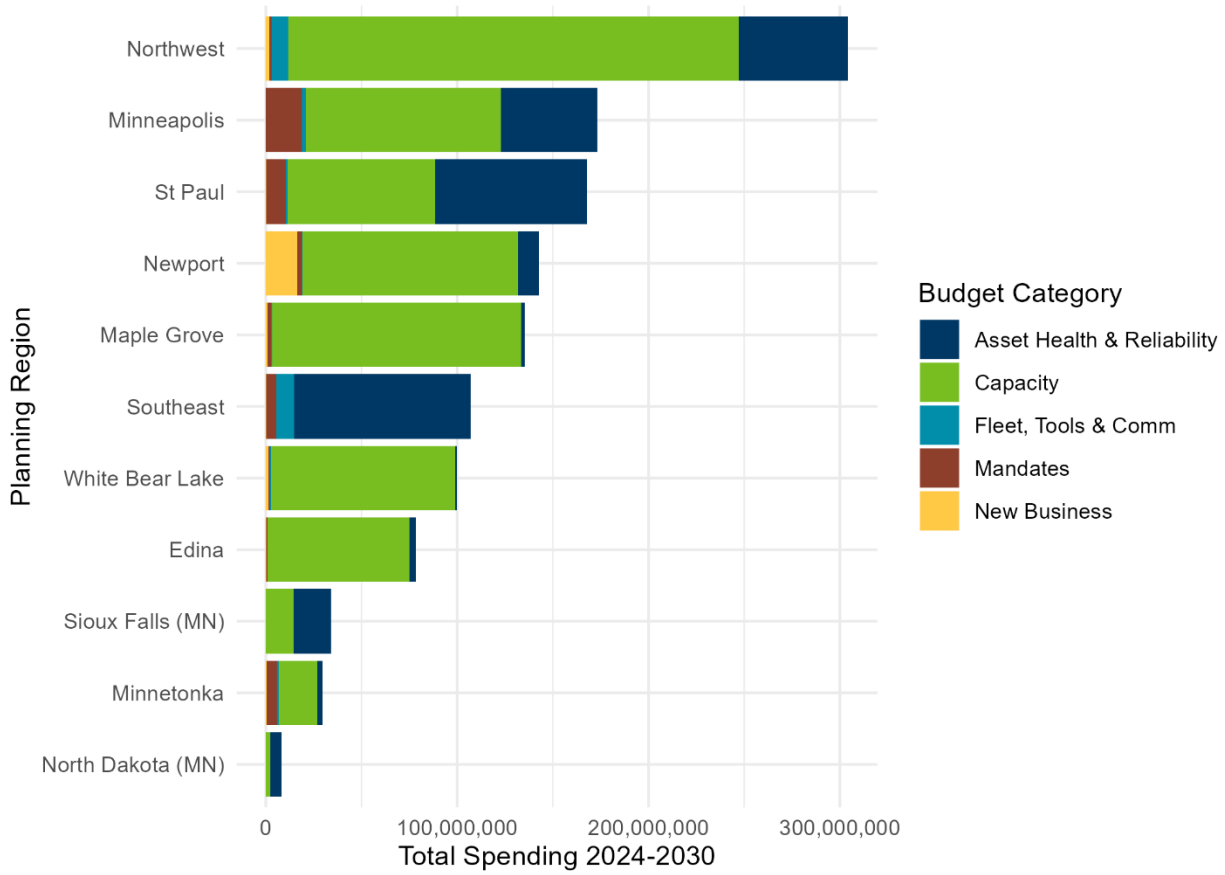


Figure 34: Xcel Spending by Budget Category and Planning Division



The variation in forecasted distribution spending across PD shown above—particularly the differing balance between asset health-driven investments and capacity-driven investments—cannot be explained by population growth alone.

First, to establish a baseline for normalizing spending across PDs, the Department requests population-related data, including:

- Current population estimates by Planning Division;
- Assumptions regarding population growth or decline by Planning Division through the IDP planning horizon; and
- An explanation of whether, and how, population trends are incorporated into distribution planning, load forecasting, and investment prioritization decisions.

These data are necessary to evaluate spending on a per-capita basis and to distinguish infrastructure investments driven by residential, commercial, or industrial customer growth from those areas or driven by other system needs.

Second, to assess whether differences in asset health spending reflect underlying infrastructure condition, the Department requests quantitative measures of asset age and condition by Planning Division, including:

- The percentage of asset value by Planning Division that have exceeded their expected service life;
- Asset condition scores, health indices, or other quantitative metrics used internally by the Company to prioritize asset replacement; and
- Historical and forecasted asset failure rates by Planning Division, where available.
- These data would clarify whether higher levels of asset health spending in certain Planning Divisions are driven by objectively older or more degraded infrastructure.

Third, to evaluate the influence of system configuration and customer mix, the Department requests quantitative metrics by Planning Division, including:

- Customer density (customers per circuit mile);
- Circuit miles per customer and per megawatt served;
- The share of residential, commercial, and industrial load; and
- The presence of large individual loads or clustered developments that materially affect capacity planning.

Finally, to determine whether reliability performance and risk exposure are influencing spending patterns, the Department requests:

- Historical reliability metrics (including SAIDI and SAIFI) by Planning Division;
- Counts of repeat or chronic outage locations by Planning Division;
- Quantitative measures of climate-related risk exposure already used by the Company in planning, including wind, flood, and wildfire risk indicators.

Absent this information, it is difficult to determine whether observed differences in distribution spending across Planning Divisions reflect underlying system needs, differences in customer growth, or inconsistent application of planning criteria.

The Department requests Xcel explain in reply comments how the following inputs are integrated within its planning framework at the Planning Division level:

- **Current population estimates by Planning Division;**
- **Assumptions regarding population growth or decline by Planning Division through the IDP planning horizon; and**
- **An explanation of whether, and how, population trends are incorporated into distribution planning, load forecasting, and investment prioritization decisions.**
- **The percentage of asset value by Planning Division that have exceeded their expected service life;**

- **Asset condition scores, health indices, or other quantitative metrics used internally by the Company to prioritize asset replacement; and**
- **Historical and forecasted asset failure rates by Planning Division, where available.**
- **These data would clarify whether higher levels of asset health spending in certain Planning Divisions are driven by objectively older or more degraded infrastructure.**
- **Customer density (customers per circuit mile);**
- **Circuit miles per customer and per megawatt served;**
- **The share of residential, commercial, and industrial load; and**
- **The presence of large individual loads or clustered developments that materially affect capacity planning.**
- **Historical reliability metrics (including SAIDI and SAIFI) by Planning Division;**
- **Counts of repeat or chronic outage locations by Planning Division;**
- **Quantitative measures of climate-related risk exposure already used by the Company in planning, including wind, flood, and wildfire risk indicators.**

After reviewing Xcel's response, the Department will make a formal data request in reply comments.

IV. DEPARTMENT RECOMMENDATIONS

Based on analysis of Xcel's 2025 IDP and the information in the record, the Department has prepared recommendations, which are provided below. The recommendations correspond to the subheadings of Section III above.

REQUESTS FOR ADDITIONAL INFORMATION DURING REPLY COMMENTS:

E. VALUE OF RELIABILITY

- E.1. The Department requests Xcel explain in reply comments why it is reasonable to assume reliability benefits that are higher than the MISO value of lost load.

F. FORECASTING RESULTS AND METHODOLOGY

- F.1. The Department requests that Xcel explain in reply comments:
  - *A.* Why Planning Divisions encompass areas well beyond the Company's Minnesota service territory;
  - *B.* Whether load, asset, or spending data from outside Xcel's service territory are embedded in PD-level forecasts used in the IDP; and
  - *C.* How the Company ensures that Minnesota-specific planning and regulatory decisions are not influenced by non-jurisdictional conditions.
- F.2. The Department requests that Xcel explain in reply comments the highlighted values in Table 5 and reconcile these projections with historical patterns.
- F.3. The Department therefore requests that Xcel provide additional detail in reply comments regarding the drivers of projected peak load growth, including:

A. The specific adoption rates for EVs and electric heating technologies assumed in each Planning Division;
B. The empirical data sources used to justify these adoption rates;
C. Explicit assumptions regarding the availability and level of subsidies and incentives over the forecast period;
D. Sensitivity analyses showing how peak load forecasts change under alternative adoption and policy scenarios; and
E. An explanation of how load diversity, customer behavior, and demand management are reflected in peak load estimates.

J. COST-BENEFIT ANALYSIS

- **[TRADE SECRET DATA HAS BEEN EXCISED]**

K. GRID MODERNIZATION

- K.1. The Department requests that Xcel explain in reply comments if and how Xcel intends to incorporate localized grid benefits from DERMS into its standard load and DER hosting capacity planning assumptions and non-wires alternatives processes.
- K.2. The Department requests that Xcel explain in reply comments if the Company intends to contract with a single vendor for each of its Aggregator DERMS and Grid DERMS solutions, such that a total of two vendors will provide all planned DERMS services, or whether Xcel intends to contract with other DERMS vendors.

L. PLANNED NET LOAD

- L.1. The Department requests that Xcel, in reply comments, provide a justification for the continued use of a flat 15% factor for the current IDP cycle when the data suggests a significantly higher DF_{PV} is warranted for those months.

P. EQUITY ANALYSIS

- P.1. The Department requests Xcel explain in reply comments causes behind the variation of outages across income groups. Xcel should explain if there are alternative ways to look at the outage duration across income groups, and any should explain analyses Xcel has done on this topic.
- P.2. The Department requests Xcel explain in reply comments causes behind the variation in outages across census tracts with varying levels of non-white population. Xcel should explain if there are alternative ways to look at the of outage duration across racial groups, and should explain if any analyses Xcel has done related to incorporating equity considerations in reliability planning.

Q. DATA REQUESTS FOR GEOSPATIAL ANALYSIS

- Q.1. The Department requests Xcel explain in reply comments how the following inputs are integrated within its planning framework at the Planning Division level:
    - Current population estimates by Planning Division;
    - Assumptions regarding population growth or decline by Planning Division through the IDP planning horizon; and
    - An explanation of whether, and how, population trends are incorporated into distribution planning, load forecasting, and investment prioritization decisions.
    - The percentage of asset value by Planning Division that have exceeded their expected service life;
    - Asset condition scores, health indices, or other quantitative metrics used internally by the Company to prioritize asset replacement; and
    - Historical and forecasted asset failure rates by Planning Division, where available.
    - These data would clarify whether higher levels of asset health spending in certain Planning Divisions are driven by objectively older or more degraded infrastructure.
    - Customer density (customers per circuit mile);
    - Circuit miles per customer and per megawatt served;
    - The share of residential, commercial, and industrial load; and
    - The presence of large individual loads or clustered developments that materially affect capacity planning.
    - Historical reliability metrics (including SAIDI and SAIFI) by Planning Division;
    - Counts of repeat or chronic outage locations by Planning Division;
    - Quantitative measures of climate-related risk exposure already used by the Company in planning, including wind, flood, and wildfire risk indicators.

PRELIMINARY RECOMMENDATIONS:

C. STRATEGIES FOR DISTRIBUTION SYSTEM OPTIMIZATION

- C.1. The Department recommends the Commission order Xcel to provide an update to each program cost benefit analysis ten years after the initial presentation of the cost benefit analysis.
- C.2. The Department recommends the Commission order Xcel to provide a cost benefit analysis of at least three discretionary programs with a total five-year budget of at least $250 million .
- C.3. The Department recommends the Commission order all new Xcel spending projects with a five-year budget over $25 million, that were approved for cost recovery since 2021, report five years of actual outcomes compared to forecasted outcomes in the IDP.
- C.4. The Department recommends that the Commission create a new filing requirement which states: All new distribution spending projects and programs with an estimated historical or forecasted five-year budget of $25 million or greater shall, at minimum, address the following:
    A. Estimated cost or range for the project/program;
    B. Consideration of feasible alternatives to the proposed spending;
    C. Quantitative estimation of expected outcomes; and
    D. Sensitivity analysis of cost and outcome assumptions.

- C.5. The Department recommends the Commission create a planning standard review process that shall:
  - *A.* Identify the main system planning standards that Xcel uses for each Commission-approved review topic;
  - *B.* Select one or more planning standards, in agreement with intervenors, to review before the next IDP;
  - *C.* Set alternative system planning scenarios to analyze, in agreement with intervenors;
  - *D.* Perform a quantitative analysis of alternative system planning standards that measure estimated costs and benefits of alternative system planning standards;
  - *E.* Require Xcel to present the results of steps A-D in the next IDP cycle; and
  - *F.* Request comments to approve, modify, or reject the revised system planning standards for each Commission-approved review topic.
- C.6. The Department recommends the Commission establish the following system planning standard review schedule, with each phase to repeat every eight years:
  - 2027: Capacity and Wildfire
  - 2029: Reliability and Asset Health
  - 2031: Grid Modernization, Distributed Energy Resources, and Operation and Maintenance
  - 2033: Budgeting
- C.7. The Department recommends the Commission establish an ad hoc system planning standard review process that shall:
  - *A.* Allow any intervenor to request a planning standard review;
  - *B.* Set the parameters that shall be reviewed;
  - *C.* Require the Commission to approve, modify, or reject the request for a planning standard review;
  - *D.* Require Xcel to present the results of the planning standard review in its next IDP; and
  - *E.* Request comments to approve, modify, or reject Xcel's system planning standard.
- C.8. The Department recommends the Commission order Xcel to disclose all changes to its system planning standards in its IDP.
- C.9 The Department recommends the Commission order the Executive Secretary to create a work group to identify IDP filing requirements that Xcel and intervenors agree can be removed.

F. FORECASTING RESULTS AND METHODOLOGY

- F.1. The Department recommends the Commission create a new IDP filing requirement to provide a comparison of forecast accuracy for each vintage and scenario (IDP Low, Medium, High) in Xcel's LoadSEER forecasts compared to actuals.

G. CAPACITY

- G.1. The Department recommends the Commission order a review of the following capacity planning standards, to be presented in Xcel's 2027 IDP:
  - *A.* Capacity forecasting and accuracy
  - *B.* N-0 forecast uncertainty margin and the use of AMI or other actual data

C. N-1 probability of coincident peak load and N-1 contingencies
D. N-1 screening based on cost effectiveness
E. Sizing new assets for future load growth
F. Capacity Risk Framework
G. Project Prioritization

H. WILDFIRE

- H.1. The Department recommends Xcel integrate the locational information from its medically necessary equipment certification form into its wildfire mitigation plan.
- H.2. The Department recommends that future (outside of the current rate case's test and planning years) wildfire mitigation proposals be filed with the Commission as a comprehensive Wildfire Mitigation Plan. The Department recommends the Company's Wildfire Mitigation Plan be filed as an attachment or supplement to its IDP.
- H.3. The Department recommends the Commission require Xcel to include the following in its Wildfire Mitigation Plan:
    - Of the overall Wildfire Mitigation Planning process:
        - A description of the intent of the Company in mitigating wildfire risk (i.e. mitigating utility-caused wildfires/minimizing liability or mitigating fire damage to utility assets),
        - A definition of "wildfire" as it is used for utility identification, planning and mitigation.
        - A discussion of its risk modelling, mapping and prioritization process within its Wildfire Mitigation Plan.
        - The most recent version of its wildfire risk map with a narrative explanation of the highest risk areas, and any changes from the last iteration of the Wildfire Mitigation Plan.
        - Reporting on the number and locations of wildfires experienced in its territory over the last ten years, the number of outages caused by wildfire, and the average length of wildfire-related outage.
        - Reporting on the efficacy of its wildfire mitigation strategy in reducing wildfire-related outages (i.e. After deployment of the rate-case-approved wildfire mitigation measures, wildfire-related outages in Xcel's territory decreased 50 percent; the number of wildfires in Xcel's service territory decreased from 100 to 50 since the filing of the Company's last IDP resulting in approximately 10 fewer outages.[260])
        - Discussion of its use of its Public Safety Power Shutoff Program, including the number of PSPS outages, cause of the PSPS outage, average length of a PSPS outage, if/how notice was provided to customers, and measures the Company employs to protect customers that are medically dependent on electric service.

[260] Values are arbitrary given as examples for how Xcel could demonstrate the efficacy of its Wildfire Mitigation Plan.

- Provide the Wildfire Safety Operations Playbook, the PSPS Playbook, and the PSPS Communications Playbook as attachments or provide the location where the Playbooks can be accessed.
- A full cost benefit analysis.

I. TARGETED UNDERGROUNDING PROPOSAL

- I.1. The Department recommends the Commission require Xcel to perform full BCA for all projects scheduled beyond the 2026 pilot phase, which must incorporate O&M savings (including avoided vegetation management and storm restoration costs), and use site-specific construction estimates and benefit calculations.
- I.2. The Department recommends the Commission approve the site selection criteria with the following modifications:
  - Require Xcel to demonstrate a minimum BCR of 1.25, using tools like the ICE, to financially justify each individual project prior to approval.
  - Limit or strictly prioritize undergrounding to sites where existing overhead infrastructure is fully depreciated to prevent stranded costs from premature retirements.
  - Require the formal quantification of alternatives, specifically enhanced vegetation management, FLISR deployment, and backlot O&M expenses, during site selection to ensure undergrounding is the most economical choice.

J. COST-BENEFIT ANALYSIS

[TRADE SECRET DATA HAS BEEN EXCISED]

K. GRID MODERNIZATION

- K.1. The Department recommends the Commission order Xcel to begin a pilot program to test localized distribution grid benefits from its Aggregator Distributed Energy Resource Management System. At minimum the pilot should:
  - Test different incentive levels to determine the optimal incentive structure;
  - Test at least two controllable load types; and
  - Provide a cost-benefit analysis of localized distribution grid benefits compared to standard distribution grid upgrades.
- K.2. The Department recommends the Commission order Xcel to provide a cost benefit analysis for all planned use cases of Aggregator DERMS, Grid DERMS, and Enterprise DERMS between 2027 and 2032 in Xcel's next IDP.
- K.3. The Department recommends the Commission order Xcel to include data on all individual FLISR installations in a single dataset, which reports on the Xcel Circuit ID, installation year, installation cost, and reliability savings, consistent with data reported in Attachment D of IR 49 in its next IDP.

L. PLANNED NET LOAD

- L.1. The Department recommends that Xcel evaluate the feasibility of accelerating the implementation of seasonal DF_{PV} values before the 2027 IDP, given that the foundational data for these factors is already present in the current filing.

M. NON-WIRE ALTERNATIVES

- M.1. The Department recommends that the Commission require Xcel to consider reliability projects in its Non-Wire Alternatives Analysis.

N. CERTIFICATION REQUEST

- N.1. The Department recommends the Commission order Xcel to develop a new customer non-wires alternatives process that will screen projects and provide a cost-benefit analysis, consistent with Xcel's existing non-wires alternatives process, for new customer solutions that include energy storage and flexible energization.
- N.2. The Department recommends the Commission certify Xcel's mobile battery request with the following certification requirements to support the Commission's evaluation of whether the proposed project serves the public interest:

  A. A cost range for the project;
  B. The expected timing for project implementation; and
  C. The utilization of a new customer non-wires alternatives screening process and cost-benefit analysis framework that will be used to select all mobile battery sites.

O. PROACTIVE CAPACITY INVESTMENTS

- O.1. The Department recommends the Commission order the Executive Secretary to open a working group tasked with the development of updating the Distribution System Reactive Upgrades Process for load.

Attachments

Attachment A – Compliance Table

Xcel Energy's 2025 Integrated Distribution Plan

Section	Heading	MPUC IDP Requirement (Notice of Updated Filing Requirements in Docket No. E002/M-23-452, based on Docket No. E002/CI-18-251)	Location	Comments
	Planning Objectives	The Commission is facilitating comprehensive, coordinated, transparent, integrated distribution plans to: 1. Maintain and enhance the safety, security, reliability, and resilience of the electricity grid, at fair and reasonable costs, consistent with the state's energy policies; 2. Enable greater customer engagement, empowerment, and options for energy services; 3. Move toward the creation of efficient, cost-effective, accessible grid platforms for new products, new services, and opportunities for adoption of new distributed technologies; and, 4. Ensure optimized utilization of electricity grid assets and resources to minimize total system costs. 5. Provide the Commission with the information necessary to understand Xcel's short-term and long- term distribution system plans, the costs and benefits of specific investments, and a comprehensive analysis of ratepayer cost and value.	Attachment C: Correlation of IDP Content to Commission's IDP Planning Objective	Information provided in Att. C. Correlation of IDP Content to Commission's IDP Planning Objective
		For filing requirements which Xcel claims is not yet practicable or is currently cost-prohibitive to provide, Xcel shall indicate for each requirement: 1. Why the Company has claimed the information is not yet practicable or is currently cost-prohibitive; 2. How the information could be obtained, at what estimated cost, and timeframe; 3. What the benefits or limitations of filing the data in future reports as related to achieving the planning objectives;	Attachment C: Correlation of IDP Content to Commission's IDP Planning Objective	Information provided in Att. C. Correlation of IDP Content to Commission's IDP Planning Objective

		4. If the information cannot be provided in future reports, what information in the alternative could be provided and how it would achieve the planning objectives.		
		Xcel shall discuss in future filings how the IDP meets the Commission's Planning Objectives, including: 1. An analysis of how the information presented in the IDP related to each Planning Objective, 2. The location in the IDP, 3. Analysis of efforts taken by the Company to improve upon the fulfillment of the Planning Objectives, and 4. Suggestions as to any refinements to the IDP filing requirements that would enhance Xcel's ability to meet the Planning Objectives[1]	Attachment C: Correlation of IDP Content to Commission's IDP Planning Objective	Information provided in Att. C. Correlation of IDP Content to Commission's IDP Planning Objective
1	Filing Date	Filing Date: Require Xcel to file annually with the Commission beginning on November 1, 2018, and biennially starting Nov 1, 2021[2] an Integrated Distribution Plan (MN-IDP or IDP) for the 10-year period following the submittal. Xcel must continue to file an annual update of baseline financial data and non-wires alternatives analysis.[3] The Commission will either accept or reject a distribution system plan by June 1 (to the extent practicable) of the following year based upon the plan content and conformance with the filing requirements and Planning Objectives listed above. The plan will be reviewed and may be combined with the Biennial Distribution System Plan required by Minn. Stat. 216B.2425 and associated certification requests, as authorized in that docket (E002/M-17-776).	This biennial IDP is being submitted on October 31, 2025 in compliance with this requirement.	This biennial IDP is being submitted on October 31, 2025 in compliance with this requirement.

[1] *In the Matter of Xcel Energy's 2018 Integrated Distribution Plan*, Docket No. E-002/CI-18-251, Order Accepting Report, and Amending Requirements (July 16, 2019), Ordering Para. 5.
[2] *In the Matter of Xcel Energy's Integrated Distribution Plan and Advanced Grid Intelligence and Security Certification Request,* Docket No. E- 002/M-19-666, *Order Accepting Integrated Distribution Plan, Modifying Reporting Requirements, and Certifying Certain Grid Modernization Projects* (July 23, 2020), Ordering Para. 2.
[3] July 23, 2020, Order (19-666) Ordering Para. 3

2	Stakeholder Meetings	Stakeholder Meeting(s): Xcel 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 input can be incorporated into the November 1 filing as deemed appropriate by the utility. At a minimum, Xcel should seek to solicit input on the following MN-IDP topics: (1) the load, electrification, and DER forecasts, and 5-year distribution system investments, (2) proposed 5-year distribution system investments, (3) anticipated capabilities of system investments and customer benefits derived from proposed actions in the next 5-years; including, consistency with the Commission's Planning Objectives (see above), and (4) any other relevant areas proposed in the MN- IDP. 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.	Chapter 9: Stakeholder Engagement	Information covered in Ch. 9, p. 1
3	Filing Requirements	Definitions: The following definitions are adopted for the purposes of these requirements. a. Distributed Energy Resources (DER): "supply and demand side resources that can be used throughout an electric distribution system to meet energy and reliability needs of customers; can be installed on either the customer or utility side of the electric meter."[4] This definition for this filing may include, but is not limited to: distributed generation, energy storage, electrified end uses that can be used as a resource, demand side management, and energy efficiency.[5] b. Electrification: the conversion of an energy-consuming device, system, or sector from non-electric sources of energy to electricity. This includes but is not limited to transportation electrification, cooking appliances, space heating and cooling, water heating, and industrial processes. c. Energy Efficiency: measures or programs that target consumer	Chapter 1: System Planning	Chapter 1: System Planning: p. 30, 65, 45.

[4] See *Minnesota Staff Grid Modernization Report,* March 2016.
[5] See report on IDP prepared for the Commission by consultants ICF International*, in In the Matter of the Commission Investigation into Grid Modernization,* Docket No. E-999/CI-15-556, Notice of Integrated Distribution Planning Report and Stakeholder Workshop (September 13, 2016), eDockets ID: 20169-124836-01.

		behavior, equipment, processes, or devices and are designed to reduce the consumption of electricity on either an absolute or per unit of production basis.		
3.A.1	Baseline Distribution System and Financial Data System Data	Modeling software currently used and planned software deployments.	Chapter 1: System Planning	information covered in Ch. 1, p. 6.
3.A.2	Baseline Distribution System and Financial Data System Data	Percentage of substations and feeders with monitoring and control capabilities, planned additions.	Chapter 4: Distribution System Statistics	information covered in Ch. 4, p. 1.
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; include information on percentage of system with each level of visibility (ex. max/min, daytime/nighttime, monthly/daily reads, automated/manual)	Chapter 4: Distribution System Statistics	information covered in Ch. 4, p. 1.
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.	Chapter 4: Distribution System Statistics	information covered in Ch. 4, p. 3.
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, including a. Setting the forecasts for distributed energy resources and electrification consistently in its resource plan and its IDP b. Conducting advanced forecasting to better project the levels of distributed energy resource and electrification deployment at a feeder level, using Xcel's advanced planning tool. c. Proactively planning investments in hosting capacity and other necessary system capacity to allow distributed generation, electrification, and electric vehicle additions consistent with the forecast for distributed energy resources and electrification. d. Improving non-wires alternatives analysis, including market solicitations for deferral opportunities to make sure Xcel can take advantage of distributed energy resources.	Chapter 1: System Planning Chapter 8: Non-Wires Alternatives Analysis	Information covered in Ch. 1 (p. 25) and 8 (p. 1-2)

		e. Planning for aggregated distributed energy resources to provide system value including energy/capacity during peak hours[6]		
3.A.6	Baseline Distribution System and Financial DataSystem Data	Discussion of how DERs and electrification is considered in load forecasting [and thus system planning] and any expected changes in load forecasting methodology	Chapter 1: System Planning	Information covered in Ch. 1, p. 35.
3.A.7	Baseline Distribution System and Financial Data System Data	Discussion if and how IEEE Std. 1547-2018[7] impacts distribution system planning considerations (e.g., opportunities & constraints related to interoperability and advanced inverter functionality). [IEEE Standard 1547-2018, published April 6, 2018).	Chapter 7: Distributed Energy, Resources, System Interconnection, and Hosting Capacity	Information covered in Ch. 7, p. 39.
3.A.8	Baseline Distribution System and Financial Data System Data	Estimated distribution system annual loss percentage for the prior year	Chapter 4: Distribution System Statistics	information covered in Ch. 4, p. 3.
3.A.9	~~Baseline Distribution System and Financial Data System Data~~	~~For the portions of the system with SCADA capabilities, the maximum hourly coincident load (kW) for the distribution system as measured at the interface between the transmission and distribution system~~	No longer applies. Order Point 6 in the Commission's September 16, 2024 Order omits this requirement.	No longer applies. Order Point 6 in the Commission's September 16, 2024 Order omits this requirement.
3.A.10	Baseline Distribution System and Financial Data System Data	Total distribution substation capacity in kVA	Chapter 4: Distribution System Statistics	information covered in Ch. 4, p. 6.

[6] July 26, 2022, Order (21-694) Ordering Para. 4
[7] IEEE Standard 1547-2018 published April 6, 2018.

3.A.11	Baseline Distribution System and Financial Data System Data	Total distribution transformer capacity in kVA	Chapter 4: Distribution System Statistics	information covered in Ch. 4, p. 7.
3.A.12	Baseline Distribution System and Financial Data System Data	Total miles of overhead distribution wire	Chapter 4: Distribution System Statistics	Information covered in Ch. 4, p. 7.
3.A.13	Baseline Distribution System and Financial Data System Data	Total miles of underground distribution wire	Chapter 4: Distribution System Statistics	Information covered in Ch. 4, p. 7.
3.A.14	Baseline Distribution System and Financial Data System Data	Total number of distribution premises	Chapter 4: Distribution System Statistics	Information covered in Ch. 4, p. 7.
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 in which they were incurred (including application review, responding to inquiries, metering, testing, make ready, etc).	Chapter 7: Distributed Energy Resources, System Interconnection, and Hosting Capacity	Information covered in Ch. 7, p. 14.
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 charges should be broken down by category in which they were incurred (including application, fees, metering, make ready, etc.)	Chapter 7: Distributed Energy Resources, System Interconnection, and Hosting Capacity	Information covered in Ch. 7, p. 14.
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 (e.g. solar, combined solar/storage, storage, etc.)	Chapter 7: Distributed Energy Resources, System	Information covered in Ch. 7, p. 17-18.

			Interconnection, and Hosting Capacity	
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 (e.g. solar, combined solar/storage, storage, etc.)	Chapter 7: Distributed Energy Resources, System Interconnection, and Hosting Capacity	Information covered in Ch. 7, p. 18.
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 (e.g. solar, combined solar/storage, storage, etc.)	Chapter 7: Distributed Energy Resources, System Interconnection, and Hosting Capacity	Information covered in Ch. 7, p. 18-19.
3.A.20	Baseline Distribution System and Financial DataSystem Data	Total number and nameplate kW of queued DER systems as of time of filing, broken down by DER technology type (e.g. solar, combined solar/storage, storage, etc.)	Chapter 7: Distributed Energy Resources, System Interconnection, andHosting Capacity	Information covered in Ch. 7, p. 19.

3.A.21	Baseline Distribution System and Financial Data System Data	Total number of electric vehicles in service territory, by type where possible (e.g. light duty, transit, medium duty, heavy duty).[8]	Chapter 7: Distributed Energy Resources, System Interconnection, and Hosting Capacity	Information covered in Ch. 7, p. 20.
3.A.22	Baseline Distribution System and Financial Data System Data	Total number and capacity of public access electric vehicle charging stations, broken out by: a. Number and capacity of known public access Level 2 Charging Stations[9] b. Number and capacity of Level 2 Charging Stations enrolled in a utility program, broken out by program[10] c. Number and capacity of known public access direct current fast charging (DCFC) stations[11] d. Number and capacity of DCFC installed through a utility EV program, broken out by program[12] e. All other known EV charging stations (by type, ex DCFC, Level 2)	Chapter 7: Distributed Energy Resources, System Interconnection, and Hosting Capacity	Information covered in Ch. 7, p. 20-21.
3.A.23	Baseline Distribution System and Financial Data System Data	Number of units and MW/MWh ratings of battery storage	Chapter 7: Distributed Energy Resources, System Interconnection,	Information covered in Ch. 7, p. 19.

[8] *In the Matter of a Commission Inquiry into Electric Vehicle Charging and Infrastructure*, Docket No. E-999/CI-17-879, Order Accepting Filings and Establishing Requirements for Additional Filings (December 12, 2019), Ordering Para. 8.a.
[9] *Id*., at Ordering Para. 8.e
[10] *Id*., at Ordering Para. 8.e
[11] *Id*., at Ordering Para. 8.f
[12] *Id*., at Ordering Para. 8.f

			and Hosting Capacity	
3.A.24	Baseline Distribution System and Financial Data System Data	MWh saving and peak demand reductions from EE program spending in previous year	Chapter 7: Distributed Energy Resources, System Interconnection, and Hosting Capacity	Information covered in Ch. 7, p. 19.
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)	Chapter 7: Distributed Energy Resources, System Interconnection, and Hosting Capacity	Information covered in Ch. 7, p. 20.
3.A.26	Baseline Distribution System and Financial Data System Data	A high-level look at historical distribution system spending for the past 5-years and projected distribution system spending for 5-years into the future, in each category listed below: 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	Chapter 6: Distribution Financial Framework and Action Plans	Information covered in Ch. 6, p. 7.

		h. Other i. Electric Vehicle Programs[13]		
3.A.27	Baseline Distribution System and Financial DataSystem Data	Historical distribution system spending for the past 5-years and projected distribution system spending for 5-years into the future broken down by Xcel's internal distribution budget categories, itemizing any non-traditional distribution projects.	Chapter 6: Distribution Financial Framework and Action Plans	Information covered in Ch. 6, p. 8.
3.A.28	Baseline Distribution System and Financial Data System Data	All non-Xcel investments in distribution system upgrades (e.g. those required as a condition of interconnection) by subset (e.g., CSG, customer-sited, PPA, and other) and location (i.e. feeder or substation.)	Chapter 6: Distribution Financial Framework and Action Plans	Information covered in Ch.6 , p. 8.
3.A.29	Baseline Distribution System and Financial Data System Data	~~Projected distribution system spending for 5 years into the future for the categories listed above, itemizing any non-traditional distribution projects.~~	Removed from Filing Requirements per Notice of Updated Filing Requirements (6/3/25)	Removed from Filing Requirements per Notice of Updated Filing Requirements (6/3/25)

[13] *In the Matter of a Commission Inquiry into Electric Vehicle Charging and Infrastructure*, Docket No. E-999/CI-17-879, Order Accepting 2020 Transportation Electrification Plans, Adopting Additional Informational Requirements, and Establishing Biennial Filing Requirement (April 16, 2021), Ordering Para. 3.a.

3.A.29	Baseline Distribution System and Financial Data System Data	Planned distribution capital projects, including drivers for the project, timeline for improvement, summary of anticipated changes in historic spending. Driver categories should align with Xcel's internal distribution budget categories.	Chapter 6: Distribution Financial Framework and Action Plans Attachment H: Capital Project List by IDP Category Attachment I: Capital Profile Trend	Chapter 6: Distribution Financial Framework and Action Plans pg. 16-17 Attachment H: Capital Project List by IDP Category Attachment I: Capital Profile Trend
3.A.30	Baseline Distribution System and Financial Data System 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.	Chapter 1: System Planning Chapter 8: Non-Wires Alternatives Analysis	Chapter 1: System Planning pg. 92. Chapter 8: Non-Wires Alternatives Analysis
3.A.31	Baseline Distribution System and Financial Data DER Deployment	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.)	Chapter 7: Distributed Energy Resources, System Interconnection, and Hosting Capacity	Chapter 7: Distributed Energy Resources, System Interconnection, and Hosting Capacity pg. 21
3.A.32	Baseline Distribution System and Financial Data DER Deployment	DER Deployment: Information on areas of existing or forecasted high DER and/or electrification penetration. Include definition and rationale for what the Company considers “high” DER and electrification penetration.	Chapter 7: Distributed Energy Resources, System Interconnection,	Chapter 7: Distributed Energy Resources, System Interconnection,

			and Hosting Capacity	and Hosting Capacity pg. 22
3.A.33	Baseline Distribution System and Financial Data DER Deployment	DER Deployment: Information on areas with existing or forecasted abnormal voltage or frequency issues that may benefit from the utilization of advanced inverter technology.	Chapter 7: Distributed Energy Resources, System Interconnection, and Hosting Capacity	Chapter 7: Distributed Energy Resources, System Interconnection, and Hosting Capacity pg. 41
3.A.34	Baseline Distribution System and Financial Data DER Deployment	Information on distribution upgrades made to accommodate electrification, when known, including whether it was reactive to new load or based on a short-term forecast.	Chapter 7: Distributed Energy Resources, System Interconnection, and Hosting Capacity	Chapter 7: Distributed Energy Resources, System Interconnection, and Hosting Capacity pg. 23
3.A.35	Baseline Distribution System and Financial Data DER Deployment	Number of fuel-switching rebated granted through Xcel Energy's Conservation Optimization (ECO) plan in the prior year, broken out by technology type (air/ground source heat pump, water heater, cooking, other industrial process heat, electric vehicles, etc.)	Chapter 7: Distributed Energy Resources, System Interconnection, andHosting Capacity	Chapter 7: Distributed Energy Resources, System Interconnection, and Hosting Capacity pg. 23
3.A.36	Baseline Distribution System and Financial Data DER Deployment	Number of electric space or water heating devices enrolled in a time-of-use rate or demand response program, broken out by program type.	Chapter 7: Distributed Energy Resources, System	Chapter 7: Distributed Energy Resources, System

			Interconnection, and Hosting Capacity	Interconnection, and Hosting Capacity pg. 24
3.A.37	Electric Vehicles	Electric Vehicles: A summary table with the following information for each EV rate offering or program during the reporting period: a) Number of customers and/or vehicles enrolled at the end of the reporting period b) Total energy consumed) MWh) during each EV tariff charging period c) Peak demand (MW) and the date and time at which occurred.[14]	Transportation Electrification Plan	Data provided in TEP Section I.B.1.
3.A.38	Electric Vehicles	Electric Vehicles: Any system upgrades performed to accommodate EV charging, total costs paid by utility and by customer, and average cost per upgrade. Cost should be reported separately for the following customer groups: Residential, Government Fleet, Private Fleet, and Public Charging, Other (specify).[15]	Transportation Electrification Plan	Data provided in TEP Section I.B.3.
3.B.1	Hosting Capacity and Interconnection Requirements	Provide a narrative discussion on how the hosting capacity analysis filed annually on November 1 currently advances customer-sited DER (in particular PV and electric storage systems) and electrification, how the Company anticipates the hosting capacity analysis (HCA) identifying interconnection points on the distribution system and necessary distribution upgrades to support the continued development of distributed generation resources,[16] and any other method in which Xcel anticipates customer benefit stemming from the annual HCA.	Chapter 7: Distributed Energy Resources, System Interconnection, and Hosting Capacity	Chapter 7: Distributed Energy Resources, System Interconnection, and Hosting Capacity pg. 11

[14] December 12, 2019 Order (17-879), Ordering Para. 8b, 8c, and 8d
[15] December 12, 2019 Order (17-879), Ordering Para. 8g; April 16, 2021 Order (17-879), Ordering Para. 3.b
[16] Minn. Stat. 216B.2425, Subd. 8.

3.B.2	Hosting Capacity and Interconnection Requirements	Describe the data sources and methodology used to complete the initial review screens outlined in the Minnesota DER Interconnection Process.[17]	Chapter 7: Distributed Energy Resources, System Interconnection, and Hosting Capacity	Chapter 7: Distributed Energy Resources, System Interconnection, and Hosting Capacity pg. 13
3.C.1	Distributed Energy Resource and Electrification Scenario Analysis	In order to understand the potential impacts of faster-than-anticipated DER and electrification adoption, define and develop conceptual base-case, medium, and high scenarios regarding increased DER and electrification deployment on Xcel's system. Scenarios should reflect a reasonable mix of individual DER and electrification adoption and aggregated or bundled DER/electrification service types, dispersed geographically across the Xcel distribution system in the locations Xcel would reasonably anticipate seeing DER and electrification growth take place first, and how the [utility] would anticipate the combined impacts of simultaneous DER and electrification growth. Xcel must provide detail on how, in aggregate, the energy and climate goals of the Minnesota communities it serves, along with customer preference trends, are reflected. In particular, distribution generation planning should include consideration of local community generation goals and beneficial electrification.[18] For electric vehicle forecasts scenarios, Xcel shall provide base-case, medium, and high adoption, capacity, and energy forecasts by sector (light duty, medium duty, and heavy duty).[19]	Chapter 1: System Planning Attachment K	Chapter 1: System Planning pg. 34 Attachment K

[17] *In the Matter of Updating the Generic Standards for the Interconnection and Operation of Distributed Generation Facilities Established Under Minn. Stat. § 216B.1611*, Docket No. E-999/CI-16-521, Order Establishing Updated Interconnection Process and Standard Interconnection Agreement (August 13, 2018), establishing Minnesota's Distributed Energy Resources Interconnection Process (MN DIP) 3.2, "Initial Review."
[18] July 23, 2020 Order (19-666), Ordering Para. 4
[19] December 12, 2019 Order (17-879), Ordering Para. 8h and 8i

3.C.2	Distributed Energy Resource and Electrification Scenario Analysis	Include information on methodologies used to develop the low, medium, and high scenarios, including the DER and electrification adoption rates (if different from the minimum 10% and 25% levels), geographic deployment assumptions, expected DER and electrification 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.	Chapter 1: System Planning	Chapter 1: System Planning pg. 34
3.C.3	Distributed Energy Resource and Electrification Scenario Analysis	Provide a discussion of the processes and tools that would be necessary to accommodate the specified levels of DER and electrification 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 and electrification adoption, potential barriers to DER and electrification integration, and the types of system upgrades that may be necessary to accommodate the DER and electrification at the listedpenetration levels.	Chapter 7: Distributed Energy Resources, System Interconnection, and Hosting Capacity	Chapter 7: Distributed Energy Resources, System Interconnection, and Hosting Capacity pg. 24
3.C.4	Distributed Energy Resource Scenario Analysis	Include information on anticipated impacts from FERC Order 841[22] (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) [22] Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators, 162 FERC ¶61,127 (February 28, 2018)	Chapter 7: Distributed Energy Resources, System Interconnection, and Hosting Capacity	Chapter 7: Distributed Energy Resources, System Interconnection, and Hosting Capacity pg. 42
3.D.1	Long-Term Distribution System Modernization and Infrastructure Investment Plan	*[Merged into 3.D.2 per July 16, 2019 Order, Order Point 4] 18-251*	N/A	NA

3.D.2	Long-Term Distribution System Modernization and Infrastructure Investment Plan	Xcel shall provide a 5-year Action Plan as part of a 10-year long term plan[20] for distribution system developments and investments in grid modernization based on internal business plans and considering the insights gained from the DER and electrification future analysis, hosting capacity analysis,[21] and non-wires alternatives analysis. The 5-year Action Plan should include a detailed discussion of the underlying assumptions (including load growth assumptions) and the costs of distribution system investments planned for the next 5-years (expanding on topics and categories listed above).	Chapter 5: Grid Modernization Chapter 6: Distribution Financial Framework and Action Plans	Chapter 5: Grid Modernization pg. 24-26. Chapter 6: Distribution Financial Framework and Action Plans pg. 25
		Xcel should include specifics of the 5-year Action Plan investments. Topics that should be discussed, as appropriate, include at a minimum:	See 3.D.2 Subparts below.	See 3.D.2 Subparts below.
3.D.2.a	Long-Term Distribution System Modernization and Infrastructure Investment Plan	Overview of investment plan: scope, timing, and cost recovery mechanism	Chapter 5: Grid Modernization	Chapter 6: Distribution Financial Information and Action Plans pg. 27-28
3.D.2.b	Long-Term Distribution System Modernization and Infrastructure Investment Plan	Grid Architecture: Description of steps planned to modernize the utility's grid and tools to help understand the complex interactions that exist in the present and possible future grid scenarios and what utility and customer benefits that could or will arise.[22]	Chapter 5: Grid Modernization	Chapter 5: Grid Modernization pg. 5-7
3.D.2.c	Long-Term Distribution System Modernization and Infrastructure Investment Plan	Alternatives analysis of investment proposal: objectives intended with a project, general grid modernization investments considered, alternative cost and functionality analysis (both for the utility and the customer), implementation order options, and considerations made in pursuit of short-term investments. The analysis should be sufficient enough to justify and explain the investment.	N/A - no investment proposal	NA - no investment proposal

[20] Modified by July 16, 2019, Order (18-251), Ordering Para. 4
[21] Modified by July 16, 2019, Order (18-251), Ordering Para. 4
[22] See https://gridarchitecture.pnnl.gov/

3.D.2.d	Long-Term Distribution System Modernization and Infrastructure Investment Plan	System interoperability and communications strategy	Chapter 5: Grid Modernization	Chapter 5: Grid Modernization pg. 12, pg. 37
3.D.2.e	Long-Term Distribution System Modernization and Infrastructure Investment Plan	Costs and plans associated with obtaining system data (EE load shapes, PV output profiles with and without battery storage, capacity impacts of DR combined with EE, EV charging profiles, load profiles of electrification, etc.)	Chapter 1: System Planning	Chapter 1: System Planning pg. 60
3.D.2.f	Long-Term Distribution System Modernization and InfrastructureInvestment Plan	Interplay of investment with other utility programs (effects on existing utility programs such as demand response, efficiency projects, etc.)	Chapter 5: Grid Modernization	Chapter 6: Distribution Financial Information and Action Plans pg. 29
3.D.2.g	Long-Term Distribution System Modernization and Infrastructure Investment Plan	Customer anticipated benefit and cost	Attachment D: Distribution Risk Scoring Methodology Attachment E: Risk Scored Project Details Attachment F: Certification Request Attachment G: Distribution Function NPV	Attachment D: Distribution Risk Scoring Methodology Attachment E: Risk Scored Project Details Attachment F: Certification Request Attachment G: Distribution Function NPV
3.D.2.h	Long-Term Distribution System Modernization and	Customer data and grid data management plan (how it is planned to be used and/or shared with customers and/or third parties)	Chapter 5: Grid Modernization	Chapter 5: Grid Modernization pg. 25

	Infrastructure Investment Plan			
3.D.2.i	Long-Term Distribution System Modernization and Infrastructure Investment Plan	Plans to manage rate or bill impacts, if any.	Chapter 6: Distribution Financial Framework and Action Plans	Chapter 6: Distribution Financial Framework and Action Plans pg. 28-29
3.D.2.j	Long-Term Distribution System Modernization and Infrastructure Investment Plan	Impacts to net present value of system costs (in NPV RR/MWh or MW)	Chapter 6: Distribution Financial Framework and Action Plans Attachment G: Distribution Function NPV	Chapter 6: Distribution Financial Framework and Action Plans pg. 29, Attachment G: Distribution Function NPV
3.D.2.k	Long-Term Distribution System Modernization and Infrastructure Investment Plan	For each grid modernization project in its 5-year Action Plan, Xcel should provide a cost-benefit analysis based on the best information it has at the time and include a discussion of non-quantifiable benefits. Xcel shall provide all information used to support its analysis.[23]	Cost and Benefit Information for a Mobile Battery Certification Request are included in Attachment F.	Cost and Benefit Information for a Mobile Battery Certification Request are included in Attachment F.
3.D.2.l	Long-Term Distribution System Modernization and Infrastructure Investment Plan	Status of any existing pilots or potential for new opportunities for grid mod pilots.	Chapter 5: Grid Modernization	Chapter 5: Grid Modernization pg. 46

[23] *July 16, 2019, Order (18-251), Ordering Para. 3*

3.D.2.m	Long-Term Distribution System Modernization and Infrastructure Investment Plan	The results of its annual distribution investment risk-ranking and a description of the risk-ranking methodology.[24]	Chapter 1: System Planning Attachment D: Distribution Risk Scoring Methodology	Chapter 1: System Planning. Pg. 4 Attachment D: Distribution Risk Scoring Methodology
3.D.2.n	Long-Term Distribution System Modernization and Infrastructure Investment Plan	Information on forecasted net demand, capacity, forecasted percent load, risk score, planned investment spending, and investment summary information for feeders and substation transformers that have a risk score or planned investment in the budget cycle in future IDPs.[25]	Chapter 1: System Planning Attachment E: Risk Scored Project Details	Chapter 1: System Planning pg. 4Attachment E: Risk Scored Project Details
3.D.2.o	Long-Term Distribution System Modernization and InfrastructureInvestment Plan	Long-range distribution studies conducted since the last IDP.[26]	N/A; addressed in Chapter 1: System Planning	N/A; addressed in Chapter 1: System Planning pg. 92
3.D.3	Long-Term Distribution System Modernization and Infrastructure Investment Plan	In addition to the 5-year Action Plan, Xcel shall provide a discussion of its vision for the planning, development, and use of the distribution system over the next 10 years. The 10-year Long-Term Plan discussion should address 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 and electrification into future planning processes based on the DER and electrification futures analysis, and any other types of changes that may need to take place in the tools and processes Xcel is currently using.	Chapter 6: Distribution Financial Framework and Action Plans	Chapter 6: Distribution Financial Framework and Action Plans pg. 32

[24] July 16, 2019, Order (18-251), Ordering Para. 9
[25] July 16, 2019, Order (18-251), Ordering Para. 10
[26] July 16, 2019, Order (18-251), Ordering Para. 11

3.E.1	Non-Wires (Non-Traditional) Alternatives Analysis	Xcel shall provide a detailed discussion of all distribution system projects in the filing year and the subsequent 5 years that are anticipated to have a total cost of greater than $2 million. For any forthcoming project or project in the filing year, which cost $2 million or more, provide an analysis on how non-wires alternatives compare in terms of viability, price, and long-term value.	Chapter 8: Non-Wires Alternatives Analysis	Chapter 8: Non-Wires Alternatives Analysis pg. 1
3.E.2	Non-Wires (Non-Traditional) Alternatives Analysis	Xcel 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.	Chapter 8: Non-Wires Alternatives Analysis	Chapter 8: Non-Wires Alternatives Analysis pg. 1
3.F.1	Transportation Electrification Plan	Xcel shall provide a summary of the utility's ongoing transportation electrification efforts, including existing programs and projects in development over at least the next 2 years.[30] [30] December 12, 2019 Order (17-879), Ordering Para. 8j	Transportation Electrification Plan	Data provided in TEP Section I.B.1.
3.F.2	Transportation Electrification Plan	Xcel shall provide a discussion of how it plans to facilitate:[27] a. availability and awareness of public charging infrastructure, including an assessment of the private sector fast charging marketplace for the utility's service territory b. availability of residential charging options for both single family and multiple unit dwellings c. programs or tariffs in development to address flexible load or reduce	Transportation Electrification Plan	Data provided in TEP Section I.B.6.

[27] December 12, 2019 Order (17-879), Ordering Para. 8k

		metering and data costs; and d. fleet electrification.		
3.F.3	Transportation Electrification Plan	Xcel shall provide a discussion of how it plans to optimize EV benefits, including a discussion of how to align charging with periods of lower customer demand and higher renewable energy production and by improving grid management and overall system utilization/efficiency.[28]	Transportation Electrification Plan	Data provided in TEP Section I.B.3.
3.F.4	Transportation Electrification Plan	Xcel shall include a discussion of how it plans to encourage more customers with electric vehicles to participate in managed charging.[29]	Transportation Electrification Plan	Data provided in TEP Section I.B.4.
3.F.5	Transportation Electrification Plan	Xcel shall provide a discussion that addresses divestment issues and identifies possible divestment strategies for its DCFC Network approved in Docket 20-745 at the conclusion of the pilot program.[30]	Transportation Electrification Plan	Data provided in Section TEP I.B.6.
3.F.6	Transportation Electrification Plan	Xcel shall provide evaluations of non-pilot EV programs that examine the cost-effectiveness of the programs as currently designed and potential changes that could improve their cost-effectiveness.[31]	Transportation Electrification Plan	Data provided in TEP Section I.B.4.
3.F.7	Transportation Electrification Plan	Xcel shall provide a summary of customer EV education initiatives. The Company does not need to provide specific examples of outreach materials.[32]	Transportation Electrification Plan	Data provided in Section I.B.7.
3.F.8	Transportation Electrification Plan	Xcel shall provide summaries of any proposals or pilots, including links to full reports, submitted to other regulatory agencies or jurisdictions (for example, proposals submitted under Conservation Improvement Programs or pilots run in other states).[33]	Transportation Electrification Plan	Data provided in TEP Section I.C and Att. C.

[28] December 12, 2019 Order (17-879), Ordering Para. 8m
[29] *In the Matter of a Commission Inquiry into Electric Vehicle Charging and Infrastructure*, Docket No. E-999/CI-17-879, Order Accepting 2021 Transportation Electrification Plans and Adopting Additional Informational Requirements (May 17, 2022), Ordering Para. 4.
[30] *In the Matter of Xcel Energy's Petition for Approval of Electric Vehicle Programs as part of its COVID-19 Pandemic Economic Recovery Investments*, Docket No. E-002/M-20-745, Order Approving Public Charging Station Proposal (April 27, 2022), Ordering Para. 8.
[31] In the Matter of a Commission Inquiry into Electric Vehicle Charging and Infrastructure, Docket No. E-999/CI-17-879, Order Accepting 2020 Transportation Electrification Plans, Adopting Additional Informational Requirements, and Establishing Biennial Filing Requirement (Apr 16, 2021), Ordering Para. 3.c.
[32] December 12, 2019 Order (17-879), Ordering Para. 8l
[33] December 12, 2019 Order (17-879), Ordering Para. 8n

3.F.9	Transportation Electrification Plan	Xcel shall provide citations with links to the most recent reports for any ongoing EV pilots or programs.[34]	Transportation Electrification Plan	Data provided in TEP Section I.B.1.
3.F.10	Transportation Electrification Plan	Xcel shall provide historical spending for the past 5-years on all transportation electrification initiatives broken down across sections of its budget: Budget Category (ex. Distribution, IT, Transmission, etc.), Capital, O&M, Marketing & Communications, Other (provide explanation of what is in "other")	Transportation Electrification Plan	Data provided in TEP Section I.B.2.
3.F.11	Transportation Electrification Plan	Xcel shall provide future spending for the next 5-years on all transportation electrification initiatives broken down across sections of its budget: Budget Category (ex. Distribution, IT, Transmission, etc.), Capital, O&M, Marketing & Communications, Other (provide explanation of what is in "other")	Transportation Electrification Plan	Data provided in TEP Section III.D.
Order Point		**MPUC IDP Requirement (8/7/18 Order in Docket Nos. E002/M-17-775 and E002/M-17-776**	**Location**	**Comment**
11		Xcel may file a Grid Modernization Report and certification request on November 1, 2018 in combination with an Integrated Distribution Plan in Docket No. E-002/CI-18-251. The filing should include for any certification request(s) at a minimum: (1) details on why the project is necessary for grid modernization; (2) how it is in the public interest; (3) how it is consistent with the Commission's Guiding Principles for Grid Modernization (Docket 15-556); (4) the intended objectives for the project; (5) a description of the available alternatives to meet the intended objectives; (6) a cost benefit analysis of the project; (7) and potential interrelation with other initiatives, projects, and Xcel's long-term grid modernization plans.	Attachment F: Certification Request	Attachment F: Certification Request
Order Point		**MPUC IDP Requirement (7/16/19 Order in Docket No. E002/CI-18-251)**	**Location**	**Comment**

[34] December 12, 2019 Order (17-879), Ordering Para. 8o

6		Xcel shall provide additional information on the Incremental Customer Investment Initiative and the System Expansion or Upgrade for Reliability and Power Quality increases beginning in 2021.	Not applicable for 2025 IDP. See Company's October 30, 2020 filing in Docket No. E002/M-19-666 at Page 6. **Item will be removed in next IDP.**	Not applicable for 2025 IDP. See Company's October 30, 2020 filing in Docket No. E002/M-19-666 at Page 6. **Item will be removed in next IDP.**
7		Xcel shall make the development of enhanced load and DER forecasting capabilities, as well as, tracking and updating of actual feeder daytime minimum loads, a priority in 2019 and include a detailed description of its progress in the Company's 2019 IDP.	Not applicable for 2025 IDP. No longer relevant - provided in Docket No. E002/M-19-666. **Item will be removed in next IDP.**	Not applicable for 2025 IDP. No longer relevant - provided in Docket No. E002/M-19-666. **Item will be removed in next IDP.**
8		Xcel shall provide all information, analysis, and assumptions used to support the cost/benefit ratio for AMI, FAN and FLISR; and IVVO and CVR cost-benefit analysis as part of its 2019 IDP filing or other future filings.	Not applicable for 2025 IDP. No longer relevant - provided in Docket No. E002/M-19-666. **Item will be removed in next IDP.**	Not applicable for 2025 IDP. No longer relevant - provided in Docket No. E002/M-19-666. **Item will be removed in next IDP.**
Order Point		**MPUC IDP Requirement (7/16/19 Order in Docket No. E002/CI-18-251)**	**Location**	**Comment**

5		Xcel must allow any interested person to participate in stakeholder engagement meetings regarding its IDP and HCA.	Chapter 9: Stakeholder Engagement	Chapter 9: Stakeholder Engagement
6		Xcel must engage stakeholders in further advancing the Company's NWA Analysis, including, but not limited to, screening criteria, analysis methodology and assumptions, and NWA evaluation parameters.	Chapter 9: Stakeholder Engagement	Chapter 9: Stakeholder Engagement pg. 23
9		The Commission requests that the Department file a report by November 1, 2020, including recommendations on specific metrics, detailed methods for evaluating performance, and consumer protections or other conditions, including cost caps, that should be applied to the certified projects. The report should be informed by a stakeholder process and will be made part of the record for any future cost recovery proceedings. **Xcel must participate in the stakeholder process, which must be open to all interested parties, and fully cooperate with the Department.**	Not applicable for 2025 IDP. Confirmed - Xcel Energy participated in all workshops for Docket No. E002/DI-20-627 (10/23/2020; 11/20/2020). **Item will be removed in next IDP.**	Not applicable for 2025 IDP. Confirmed - Xcel Energy participated in all workshops for Docket No. E002/DI-20-627 (10/23/2020; 11/20/2020). **Item will be removed in next IDP.**
12		Xcel must produce a draft rate design "roadmap" with input from stakeholders and file it with the Commission by October 1, 2020. The Commission delegates authority to the Executive Secretary to set schedules and gather information on, or refer to the appropriate docket(s), the following: a. A summary of the Company's current advanced rate designs and demand management programs, advanced rate designs in development, and relevant industry best practices. b. A timeline for proposing advanced rates and/or demand management programs for all customer classes. c. A discussion on what should be discussed in petitions for rate design changes, including:	Not applicable for 2025 IDP. Filed 10/1/2020 in Docket No. E002/M- 19-666. **Item will be removed in next IDP**.	Not applicable for 2025 IDP. Filed 10/1/2020 in Docket No. E002/M-19-666. **Item will be removed in next IDP.**

		i. Whether program design strategies will be needed to support low-income customer participation in these offerings, ii. Application to distributed energy resources and beneficial electrification, iii. Implementation plans, including education and outreach to customers, and iv. Evaluation plans.		
13		60 days prior to a petition to seek rider recovery for AGIS costs, Xcel Energy shall file preferred procedural paths forward with one option being a contested case. The Commission will make a procedural and scoping decision prior to the consideration of a rider recovery determination. The Executive Secretary is authorized to establish a comment and reply schedule prior to the procedural and scoping hearing.	Not applicable to 2025 IDP. Filed 8/28/2020 in Docket No. E002/M- 19-666. **Item will be removed in next IDP.**	Not applicable to 2025 IDP. Filed 8/28/2020 in Docket No. E002/M-19-666. **Item will be removed in next IDP.**
Order Point		**MPUC IDP Requirement (11/2/20 Order in Docket No. E002/M-19-666)**	**Location**	**Comment**
4		Xcel Energy, Minnesota Power, Otter Tail Power, and Dakota Electric Association's IDP filing requirements in the second paragraph under Planning Objectives are corrected as shown: ~~Commission review of annual distribution system plans are is not meant to preclude flexibility for [UTILITY] to respond to dynamic changes and on going necessary system improvements to the distribution system; nor is it a prudency determination of any proposed system modifications or investments~~.	See IDP Planning Objectives for Xcel Energy with the 12/8/22 Order.	See IDP Planning Objectives for Xcel Energy with the 12/8/22 Order.
Order Point		**MPUC IDP Requirement (7/26/22 Order in Docket No. E002/M-21-694)**	**Location**	**Comment**
2		Xcel shall file its smart inverter roadmap and related consultant reports in this docket by November 1, 2022	Submitted in Annual Update, Attachment E, submitted 11/1/2022 in	Submitted in Annual Update, Attachment E, submitted 11/1/2022 in

			Docket No. E002/M-21-694. **Item will be removed in next IDP.**	Docket No. E002/M-21-694. **Item will be removed in next IDP.**
3		Xcel shall use both the WACC and societal discount rate in its NWA analysis and discuss the results of the two approaches in a future IDP stakeholder meeting.	Chapter 8: Non-Wires Alternatives Analysis	Chapter 8: Non-Wires Alternatives Analysis pg. 40
5		Within 90 days, Xcel shall make a compliance filing that outlines key differences between its Colorado and Minnesota distribution system planning processes, including but not limited to a discussion of the following: a. Orders, rules, and statutes pertaining to distribution system planning b. How Xcel Energy conducts DER and load forecasting, including the Company's implementation of LoadSEER c. How Xcel Energy conducts its NWA analysis d. How Xcel Energy conducts its Hosting Capacity analysis	Compliance filing submitted 10/24/2022 in Docket No. E002/M- 21-694. **Item will be removed in next IDP.**	Compliance filing submitted 10/24/2022 in Docket No. E002/M-21-694. **Item will be removed in next IDP.**
6		Xcel shall hold a series of stakeholder meetings to collaborate with interested parties, obtain input, and generate new ideas around a shared vision of the distribution grid of the future. This stakeholder series is intended to provide transparency into the Company's distribution planning process and explore how Minnesota's public policy goals will be realized on the distribution system and impact the Company's future plans. This stakeholder series should be timed such that stakeholder input can be incorporated into the Company's next IDP filing and next IRP filing and include at least four meetings. The topics will include, but not be limited to the following: a. Integrated Distribution Planning 101 b. Identify the public policy goals that are changing the expectations of the distribution grid and how each public policy is expected to be realized on the grid in the near- and long-term.	Compliance filing submitted 8/1/23 in Docket No. E002/M-21-694. **Item will be removed in next IDP.**	Compliance filing submitted 8/1/23 in Docket No. E002/M-21-694. **Item will be removed in next IDP.**

		c. How energy efficiency, demand response, and other DER might impact Xcel's planning processes d. How Xcel should consider and incorporate local clean energy goals in its planning processes e. What investments are necessary to achieve the distribution grid of the future, and the criteria Xcel should use to plan and prioritize those investments.		
6 cont'd		f. Prioritizing the use of "net load" in its load forecasts and system planning, including developing a methodology for incorporating the load reducing impact of distributed generation into its load forecasts and system planning processes g. Develop a methodology for valuing the load-modifying impacts of demand response in load forecasts and present a load forecast that includes demand response contributionsh. Identify appropriate transportation, building, and industrial end use electrification scenarios for inclusion in the 2023 IDP load forecasts i. How Xcel anticipates proactively planning for grid investments to allow distributed generation and EV additions consistent with the DER forecast j. Estimate the potential synergies between interconnection upgrades sand planned distribution capital investments, and discuss the anticipated overlap between planned investments and capacity constrained locations on Xcel's distribution system. Xcel shall make a compliance filing with the summary of the stakeholder process and a list of next steps by August 1, 2023. Xcel shall include a summary of the stakeholder series in its next IDP and relevant summary in its next IRP, including how it considered and incorporated stakeholder input.	Compliance filing submitted 8/1/23 in Docket No. E002/M-21-694.Item will be removed in next IDP.Chapter 1: System Planning-Order Point .f	Compliance filing submitted 8/1/23 in Docket No. E002/M-21-694. Item will be removed in next IDP. Chapter 1: System Planning-Order Point .f
7		The Commission certifies the Resilient Minneapolis Project and limits cost recover to a cost cap of $9 million unless Xcel can show by clear and convincing evidence that the costs were reasonable, prudent, and beyond the Company's control. Xcel shall file reports annually on December 1st through 2026. The first report is due on December 1, 2022 and must contain the following information: a. Define and quantify the emergency service capabilities and capacity in	Filed 12/1/22 in Docket No. E002/M-21-694. **Item will be removed in next IDP.**	Filed 12/1/22 in Docket No. E002/M-21-694. **Item will be removed in next IDP.**

		more detail and in more concrete terms than Xcel has hitherto provided in its proposal and via discovery responses. b. Report on the status of the emergency service capacity to ensure that the benefits are or can be realized, and to develop a process and a plan for demonstrating that the benefits can be realized. c. Define a process for identifying and addressing the potential situation in which either or both of the following conditions arise: the project fails to deliver all, or a large portion of Xcel's claimed quantified benefits and/or the claimed unquantified benefits cannot or are unlikely to materialize		
8		Xcel shall consult with stakeholders, including RMP site partners, on the development of a set of evaluation metrics that allow comparison to other resilience offerings. This set of evaluation metrics shall be included in Xcel's December 1 annual reports. Xcel shall provide the following information and data to the greatest extent practicable. Where the Company is not able to do so, it shall explain why. Where applicable, Xcel must include data in spreadsheet (.xlsc) format. In consultation with stakeholders Xcel shall consider the following reporting elements when developing evaluation metrics:	See 12/1/22 RMP Annual Report in Docket No. E002/M-21-694. **Item will be removed in next IDP.**	See 12/1/22 RMP Annual Report in Docket No. E002/M-21-694. **Item will be removed in next IDP.**
8.a		Xcel shall include optional feedback from site hosts and community partners, using a form Xcel distributes on an annual (or more frequent) basis, which invites partners to discuss their experience participating in the project, its impact on the organization or community, or other information partners wish to share with the Commission.	See 12/1/22 RMP Annual Report in Docket No. E002/M-21-694. **Item will be removed in next IDP.**	See 12/1/22 RMP Annual Report in Docket No. E002/M-21-694. **Item will be removed in next IDP.**
8.b		Xcel shall file a spreadsheet reporting, for each RMP site, the number of union labor jobs or contracts and the number of contracts awarded to women- and minority-owned businesses.	See 12/1/22 RMP Annual Report in Docket No. E002/M-21-694. **Item will be removed in next IDP.**	See 12/1/22 RMP Annual Report in Docket No. E002/M-21-694. **Item will be removed in next IDP.**

8.c		Xcel shall file a spreadsheet reporting, for each RMP site, the number of workers trained in the operation of energy systems and the number of energy-related jobs created.	See 12/1/22 RMP Annual Report in Docket No. E002/M-21-694. **Item will be removed in next IDP.**	See 12/1/22 RMP Annual Report in Docket No. E002/M-21-694. **Item will be removed in next IDP.**
8.d		Xcel shall record in a spreadsheet any instances of natural events or Company- orchestrated simulations in which RMP systems switch to "islanded mode" and how the system performs.	See 12/1/22 RMP Annual Report in Docket No. E002/M-21-694. **Item will be removed in next IDP.**	See 12/1/22 RMP Annual Report in Docket No. E002/M-21-694. **Item will be removed in next IDP.**
8.e		Xcel shall track in a spreadsheet or in narrative form how RMP sites' rooftop solar, BESS, and microgrid are dispatched and optimized daily to mitigate system peaks, manage and shape demand, and integrate more solar generation.	See 12/1/22 RMP Annual Report in Docket No. E002/M-21-694. **Item will be removed in next IDP.**	See 12/1/22 RMP Annual Report in Docket No. E002/M-21-694. **Item will be removed in next IDP.**
8.f		Xcel shall report in a spreadsheet, for any of the RMP site, when a generator is used, for how long, and the generator power capacity and fuel source.	See 12/1/22 RMP Annual Report in Docket No. E002/M-21-694. **Item will be removed in next IDP.**	See 12/1/22 RMP Annual Report in Docket No. E002/M-21-694. **Item will be removed in next IDP.**
8.g		Xcel shall quantify in a spreadsheet the number and type of HVAC upgrades, building envelope upgrades, energy efficiency measures, and/or demand response program undertaken at any of the RMP sites, shared at the discretion of RMP site hosts and partners.	See 12/1/22 RMP Annual Report in Docket No. E002/M-21-694. **Item will be**	See 12/1/22 RMP Annual Report in Docket No. E002/M-21-694. **Item will be**

			removed in next IDP.	**removed in next IDP.**
8.h		Xcel shall develop metrics related to resiliency benefits and energy equity and data collection on those topics.	See 12/1/22 RMP Annual Report in Docket No. E002/M-21-694. **Item will be removed in next IDP.**	See 12/1/22 RMP Annual Report in Docket No. E002/M-21-694. **Item will be removed in next IDP.**
9		Xcel shall file a letter in this docket to notify the Commission and stakeholders if the Company encounters any significant procurement challenges related to RMP, including delays, low bid numbers, or unexpected costs.	See April 19 and June 9, 2023 filings in Docket No. E002/M-21-694. **Item will be removed in next IDP.**	See April 19 and June 9, 2023 filings in Docket No. E002/M-21-694. **Item will be removed in next IDP.**
10		Xcel shall include a discussion of the RMP in comparison to battery and microgrid programs/projects in Xcel's service territories in other states, lessons learned form these programs as they move through construction and into operation, and specific details how these lessons are informing RMP project decisions, reducing costs, and/or improving efficacy. a. Xcel shall include this information in Xcel's 2023 IDP filing b. Xcel shall include this information in each of Xcel's annual reports filed in Docket No. E-002/M-21-694	See *Appendix B3* in 2023 IDP (Docket No. 23-452). No longer relevant for 2025 IDP. **Item will be removed in next IDP.**	See Appendix B3 in 2023 IDP (Docket No. 23-452). No longer relevant for 2025 IDP. **Item will be removed in next IDP.**
11		Xcel shall report on the Resilient Minneapolis Project in its quarterly reports in Docket No. E,G-999/M-20-492	See Docket No. E,G999/M-20-492. **Item will be removed in next IDP.**	See Docket No. E,G999/M-20-492. **Item will be removed in next IDP.**

Order Point		MPUC IDP Requirement (12/8/22 Order in Docket No. E002/M-21-694)	Location	Comment
3		Allows utilities to file EV data in future IDP Plans that align with the data filed in their Annual Program Electric Vehicle reports (due June 1 of each year)	Transportation Electrification Plan	TEP Plan
Order Point		**MPUC IRP Requirement (4/15/22 Order in Docket No. E002/RP-19-368)**	**Location**	**Comment**
9		Xcel shall takes steps to better align distribution and resource planning, including: A. Set the forecasts for distributed energy resources consistently in its resource plan and its Integrated Distribution Plan. B. Conduct advanced forecasting to better project the levels of distributed energy resource deployment at a feeder level, using Xcel's advanced planning tool. C. Proactively plan investments in hosting capacity and other necessary system capacity to allow distributed generation and electric vehicle additions consistent with the forecast for distributed energy resources. D. Improve non-wires alternatives analysis, including market solicitations for deferral opportunities to make sure Xcel can take advantage of distributed energy resources to address discrete distribution system costs. E. Plan for aggregated distributed energy resources to provide system value including energy/capacity during peak hours.	See corresponding IDP Requirement 3.A.5. Chapter 1: System Planning Chapter 8: Non-Wires Alternatives Analysis	See corresponding IDP Requirement 3.A.5. Chapter 1: System Planning pg. 25. Chapter 8: Non-Wires Alternatives Analysis pg. 2
Order Point		Docket No. E999/CI-16-521, Staff Briefing Papers for the May 20, 2021 Commission Meeting	Location	Comment
22		Already, the Commission has seen crossover with the DGWG and IDPs, hosting capacity analysis, grid modernization investments, and more. As mentioned, the rate-regulated utilities will discuss anticipated impacts of the FERC Orders in their IDPs to be filed November 1, 2021. Staff anticipates more robust discussion of these issues in the 2021 IDPs.	Chapter 7: Distributed Energy Resources, System Interconnection, and Hosting Capacity	Chapter 7: Distributed Energy Resources, System Interconnection, and Hosting Capacity pg. 42

Order Point		MN Electric Rate Case Requirements (Order 7/23/23 in Docket No. E002/GR-21-630)	Location	Comment
27.b		Xcel must report, beginning in its next IDP due November 1, 2023, on the FLISR budget approved in the present rate case along with a summary of FLISR's reliability results in its Integrated Distribution System Plan.	Chapter 5: Grid Modernization	Chapter 5: Grid Modernization pg. 16
29		In its next Integrated Distribution Plan, Xcel must propose and discuss ways for the IDP Process to inform financial and cost recovery issues in rate cases, including but not limited to: a. The feasibility of conducting cost-benefit analyses for discretionary portions of the distribution budget; b. The decisions needed in the IDP to provide guidance to Xcel to ensure distribution spending that may be approved in forthcoming rate cases is in alignment with policy goals established through the IDP	See *Executive Summary* of 2023 IDP (Docket No. 23-452). Not applicable for 2025. **Item will be removed in next IDP.**	See Executive Summary of 2023 IDP (Docket No. 23-452). Not applicable for 2025. **Item will be removed in next IDP.**
31		Xcel must track its planned and actual spending on reactive and proactive cable replacements and include the information as part of its IDP budget filing.	Chapter 6: Distribution Financial Framework and Action Plans	Chapter 6: Distribution Financial Framework and Action Plans pg. 13
33		The Commission rejects Xcel's proposal for the Distributed Intelligence program without prejudice and direct Xcel to refile its proposal in its next IDP consistent with the Company's Colorado settlement	Not applicable for 2025 IDP. See 2023 IDP, Appendix J: Distributed Intelligence in Docket No. E002/M- 23-452. **Item will be removed innext IDP.**	Not applicable for 2025 IDP. See 2023 IDP, Appendix J: Distributed Intelligence in Docket No. E002/M-23-452. **Item will be removed in next IDP.**

36		Xcel must file an assessment and explanation in the next IDP of whether (Integrated Volt-Var Optimization) IVVO is in the public interest.	See Appendix B1 in 2023 IDP and compliance filing filed in Docket No. E002/M-23-452 on 3/14/25. Not applicable for 2025 IDP. **Item will be removed in next IDP.**	See Appendix B1 in 2023 IDP and compliance filing filed in Docket No. E002/M-23-452 on 3/14/25. Not applicable for 2025 IDP. **Item will be removed in next IDP.**
128		The Commission adopts the Department's recommended grid modernization filing requirements	Chapter 5: Grid Modernization Chapter 6: Distribution Financial Framework and Action Plans	Chapter 5: Grid Modernization pg. 4. Chapter 6: Distribution Financial Framework and Action Plans pg. 6.
133		Xcel shall, in its next Integrated Distribution plan ("IDP), quantify the incremental hosting capacity and beneficial electrification that will be accommodated by its planned distribution system investments	See Appendix C in 2023 IDP. Not applicable for 2025 IDP. **Item will be removed in next IDP.**	See Appendix C in 2023 IDP. Not applicable for 2025 IDP. **Item will be removed in next IDP.**
Order Point		**TCR (Order 6/28/23 in Docket No. E002/M-21-814)**	**Location**	**Comment**
17		Xcel shall provide a comprehensive framework in its November 1, 2023, Integrated Distribution Plan for assessing: a. HAN, AMI, and AMI-DI specifications and related customer data access policies. b. Bring-your-own device HAN requirements and terms c. Potential terms and conditions for third-party data access to AMI, AMI-	Not applicable for 2025 IDP. **Item will be removed in next IDP.**	Not applicable for 2025 IDP. **Item will be removed in next IDP.**

		DI or HAN. d. Methods to provide customers equal access to the level of data available to the utility. e. A summary of industry customer data access standards		
Order Point		**IRA (Order 9/12/23 in Docket No. U999/CI-22-624)**	**Location**	**Comment**
1		The utilities shall maximize the benefits of the Inflation Reduction Act in […] integrated distribution plans […]. In such filings, utilities shall discuss how […] the Act has impacted planning assumptions including (but not limited to) […] the adoption rates of electric vehicles, distributed energy resources, and other electrification measures.	Chapter 6: Distribution Financial Information and Action Plans	Chapter 6: Distribution Financial Information and Action Plans pg. 15
Order Point		**MPUC IDP Requirement (5/9/24 Order in Docket No. E002/M-23-452)**	**Location**	**Comment**
21		Xcel must include the following components in its next transportation electrification plan: a. a proposal to actively manage electric vehicle charging; b. a proposal for a successor to the current Multi-Dwelling Unit (MDU) Pilot program; c. a discussion of potential modifications to the A15 and A14 rates to shift the demand charge limiter for electric vehicle charging stations; d. a discussion of how streetside charging near high concentrations of multi- dwelling units and/or renters fits within Xcel's programming; e. a discussion of how heavy-duty electric vehicle offerings fit within Xcel's programming; f. a robust discussion of equity, including an analysis of how Xcel's EV programs are serving those disproportionately impacted by transportation pollution, as well as renters, multifamily housing residents, communities of color, low-to-moderate income customers, and rural communities; and what gaps may remain; g. a discussion of how Xcel is coordinating between electric vehicle, energy efficiency, and building electrification planning, including, for	Transportation Electrification Plan	Data provided in TEP Section II.

		example, ECO programs; h. a discussion of how Xcel is supporting adoption of electric school buses, beyond its Electric School Bus V2G Demonstration, including if EVSE rebates were offered under ECO; how Xcel is mitigating and streamlining interconnection; and how Xcel is promoting or educating school bus operators and/or school districts on the availability of electric school bus funding; and i. a discussion of an optional add-on subscription tier in the EV Subscription Service program for drivers wanting to charge more than 1,000 kWh off-peak.		
Order Point		**MPUC IDP Requirement (9/16/24 Order in Docket No. E002/M-23-452)**	**Location**	**Comment**
2		Xcel shall report all DERs and DER forecasts in MWac in future IDPs.	Chapter 1: System Planning	Chapter 1: System Planning pg. 34
3		In its next IDP, Xcel shall report on its progress to improve forecasting, including:a) Refining its residential beneficial electrification forecasts to include low, medium, and high adoption scenarios.b) Presenting an initial C&I beneficial electrification forecast, or if the Company is unable to complete one by that time, the Company shall explain why not and include a detailed explanation of how it is thinking about this forecast, information challenges it raises, and approaches Xcel is considering.c) Evaluating the accuracy of LoadSEER forecasts.d) Utilizing IDP forecast scenarios to perform sensitivities on grid capacity or capital expense plans.	Chapter 1: System PlanningChapter 10- Distribution System Upgrades	Chapter 1: System Planning a)pg. 64 b) pg. 64 c) pg. 77. Chapter 10: Distribution System Upgrades d) pg. 1.
4		In future IDPs, Xcel shall provide standalone forecasts for demand response, load flexibility, and energy efficiency.	Chapter 1: System Planning	Chapter 1: System Planning pg. 45
5		Xcel shall provide a comparison of the forecast provided in the IDP to actuals in its next IDP.	Chapter 1: System Planning	Chapter 1: System Planning pg. 76

6		The Commission modifies Xcel's IDP reporting requirements to discontinue requirement 3.A.9.	N/A	NA
7		The Commission delegates authority to the Executive Secretary to work with Xcel and stakeholders on ways to modify the IDP budget categories to allow for comparisons between utilities and comparison of historic to forecasted data. The Commission delegates authority to the Executive Secretary to approve via notice a stakeholder agreement on amended reporting requirements if one is reached.	See Notice of Updated Filing Requirements filed on 6/3/25 in Docket No. E002/M-23-452	See Notice of Updated Filing Requirements filed on 6/3/25 in Docket No. E002/M-23-452
8		The Commission delegates authority to the Executive Secretary to work with Xcel, the Department, and stakeholders to modify the IDP reporting requirements to include discussions of the impacts of electrification where appropriate and consider alternative dockets and the timeliness for a beneficial electrification plan and whether the filing requirements should be part of future IDPs. The Commission delegates authority to the Executive Secretary to approve via notice a stakeholder agreement on amended reporting requirements if one is reached.	See Notice of Updated Filing Requirements filed on 6/3/25 in Docket No. E002/M-23-452	See Notice of Updated Filing Requirements filed on 6/3/25 in Docket No. E002/M-23-452
9		Xcel shall provide a discussion of how it tracks, protects, and considers the restoration of vulnerable populations and critical customer load, such as hospitals and first responder sites, during extended outage events in its next IDP.	Chapter 3: Distribution Operations	Chapter 3: Distribution Operations pg. 9
10		Xcel shall engage in additional stakeholder discussions on approaches to apply cost- benefit analyses, or a similar type of evaluation, strategically to program- level investments for discretionary projects for certification or cost recovery proceedings.	Chapter 9: Stakeholder Engagement	Chapter 9: Stakeholder Engagement pg. 10-15
11		In its next IDP, Xcel shall include a discussion of the results of stakeholder conversations about ways to conduct program-level cost-benefit analyses for relevant discretionary distribution expenditures.	Chapter 9: Stakeholder Engagement	Chapter 9: Stakeholder Engagement pg. 4, 10

12		As part of the stakeholder effort on cost-benefit analyses, Xcel shall explain how it would define "discretionary" spending in this context and to explain its cost- benefit methodology, including specifically its identification of benefits.	Chapter 6: Distribution Financial Information and Action Plans Chapter 9: Stakeholder Engagement	Chapter 6: Distribution Financial Information and Action Plans pg. 22. Chapter 9: Stakeholder Engagement pg. 11.
13		The Commission delegates authority to the Executive Secretary to work with Xcel and stakeholders to develop a proposal for what distribution data is reported in the IDP and what data continues to be reported in other dockets. The goal of the process is to develop a comprehensive list of existing distribution data reporting requirements and to identify which, if any, pieces of information are missing and should be included in future IDPs. At minimum, the proposal should address the following types of data: a) Reliability data such as SAIDI, SAIFI, CAIDI, CEMI, and CELI. b) Distribution spending by IDP budget categories. c) Whether there is available hosting capacity for generation or load at the primary system level. d) Demographic data including race and income. e) Installed DERs, ECO rebates, DR customers enrolled in programs. f) Data reported at a feeder and/or census block group level.	Distribution Data workgroup kicked off and on-going.	Distribution Data workgroup kicked off and on-going.

14		The Commission delegates authority to the Executive Secretary to establish a stakeholder process to develop a framework on cost allocation and proactive upgrades for Xcel. The stakeholder workgroup may also include Dakota Electric Association, Minnesota Power, and Otter Tail Power if they wish to participate. The Commission sets the following guidelines for the process: a) The goal of the workgroup is to develop a framework for proactive upgrades and cost allocation for Commission consideration and possible adoption. b) The process does not need to reach consensus but should aim to clearly identify areas of agreement and disagreement to facilitate a Commission decision. c) The Commission establishes a goal of completing the stakeholder process by July 1, 2025. At the conclusion of the process there will be a notice and comment period on any framework followed by a Commission decision. d) The framework should address, at minimum, the following topics: i) How to allocate the costs of proactive upgrades. ii) How to ensure any proactive upgrades are distributed in an equitable manner throughout a utility's service territory. iii) If costs are socialized among ratepayers, whether portions of the upgraded capacity should be reserved for certain customer classes. iv) How a proactive upgrade program would integrate with a utility's planned distribution investment programs. v) How a utility's other capacity programs and changes to distribution standards impact available hosting capacity. vi) How to determine where and when there is a need for proactive upgrades using forecasted DER and load adoption. vii) Whether there should be changes to any of a utility's service policy provisions such as Contributions In Aid of Construction (CIAC).	Proactive Grid Upgrades Proposal	Proactive Grid Upgrades Proposal
15		The Commission delegates authority to the Executive Secretary to approve via notice the tariff changes outlined in Xcel's letter dated June 12, 2024, if no objections are filed within 30 days of this order.	N/A	NA

16		Xcel shall track and report on the amount of each CIAC waiver granted to residential customers and the revenues foregone as a result of the waiver and file the data in its Annual EV Reports due June 1 annually. Xcel shall report the aggregate number and dollar amount of waivers starting with its 2025 IDP.	Transportation Electrification Plan	Data provided in TEP Att. H.
17		Xcel shall work with stakeholders to refine its planned net load methodology. Xcel shall also evaluate alternative approaches to applying the dependability factor, including applying it to hourly photovoltaic generation and to photovoltaic nameplate capacity. Xcel shall engage parties that commented on planned net load in this proceeding as it evaluates seasonal dependability factors and alternative planned net load approaches. Xcel shall include a report describing the results of this evaluation and changes to its proposed planned net load methodology in its next IDP.	Chapter 1: System Planning Chapter 9: Stakeholder Engagement	Chapter 1: System Planning pg. 87-90. Chapter 9: Stakeholder Engagement pg. 4, 5-10.
18		Xcel shall implement the 15 percent DFPV in the next planning cycle for N-0 risk analysis in the next IDP.	Chapter 1: System Planning	Chapter 1: System Planning pg. 87
19		Xcel shall demonstrate the Company's ability to integrate DERs with the tools available to it today and in the near term, including specifically through: a)Implementing static Flexible Interconnection prior to implementing full, dynamic Flexible Interconnection; and b)Pursuing a staged approach to Flexible Interconnection, DERMS, and Dynamic Hosting Capacity implementation.	Chapter 7: Distributed Energy Resources, System Interconnection, and Hosting Capacity	Chapter 7: Distributed Energy Resources, System Interconnection, and Hosting Capacity pg. 3
20		Xcel shall be transparent about the conditions under which the Company will use Flexible Interconnection, particularly with impacted DER owner/operators.	Chapter 7: Distributed Energy Resources, System Interconnection, and Hosting Capacity	Chapter 7: Distributed Energy Resources, System Interconnection, and Hosting Capacity pg. 3

21		The Commission directs the Distributed Generation Workgroup to take up the topic of Flexible Interconnection to work through questions related to Static Flexible Interconnection as well as Dynamic Flexible Interconnection which is enabled by DERMS.	N/A	NA
22		Xcel shall conduct robust stakeholder outreach, including specifically with DER owners/operators, and describe in a filing with the Commission its stakeholder engagement process, the materials it used to inform stakeholders about DERMS (addressing, e.g., costs, benefits, alternatives, purpose, problems it is solving), the feedback it received, and how it has addressed it. The filing shall be filed in Xcel's 2025 IDP, or at the time of request for certification or cost recovery for any DERMS investments, whichever is sooner.	Chapter 11: DERMS	Chapter 9: Stakeholder Engagement pg. 15
23		Xcel shall file a detailed roadmap for DERMS deployment that addresses the questions provided below. Xcel must adequately address these questions before any DERMS investments will be approved. The roadmap and answered questions shall be filed in Xcel's 2025 IDP, or at the time of request for certification or cost recovery for any DERMS investments, whichever is sooner.Questions to address: a) What are the alternatives to DERMS? b) What are the specific use cases for which DERMS will be utilized and who are the intended beneficiaries? c) Will participation in DER Management be voluntary or required? Will requirements vary based on resource size, resource type, program participation, market participation, or other factors? Will it be available for load interconnections (e.g., EV charging hubs) or interconnections utilizing limited import/export control systems? d) How will communications be established between Xcel's DERMS and customer DER? Who will bear the ongoing cost for any necessary communications infrastructure? e) How will capacity be allocated across new and existing managed and unmanaged interconnectors? How will capacity upgrades be justified and from whom will upgrade costs be recovered?	Chapter 11: DERMS	Ch. 11 DERMS

		f) How will prospective applicants understand the impact of DER management on the economics of their project? What information will be provided to prospective interconnectors related to expected curtailment and existing and expected grid conditions? g) What are the expected deployment and integrations costs for DERMS? What is the expected ongoing licensing, operating, and infrastructure costs to execute and maintain DERMS functionality? From whom will these costs be recovered? h) How are equity and energy justice principles being incorporated within the use cases, process design, and cost allocation?		
24		The Commission delegates authority to the Executive Secretary to open a new docket for Xcel Energy for the purposes of reviewing and approving Distributed Intelligence (DI) program terms and conditions. Xcel shall submit any requests to implement customer facing DI-enabled programs prior to rollout for Commission approval. This includes proposals the Company may make as part of its ECO portfolio. Proposals must include tariff pages with terms and conditions and be consistent with the terms of the February 18, 2022 Colorado Settlement in Proceeding No. 21A-0279E as outlined in the Commission's July 17, 2023 Order in E002/GR-21-630 and any other applicable Minnesota standards on data privacy. This is not a cost recovery docket and approval made in the docket have no bearing on prudency for future cost recovery proceedings.	Not applicable for 2025 IDP.	NA
25		Xcel shall re-evaluate IVVO for its Minnesota service area (applying the new Minnesota Test for cost-effectiveness and updated assumptions informed by PSCo's experience with IVVO). As part of this analysis, Xcel shall identify feeders where IVVO is most cost- effective, discuss the potential for targeted deployment to these areas and/or in under-resourced communities, and report on its updated evaluation within six months of this order.	See compliance filing made on 3/14/25 in Docket No. E002/M-23-452.	See compliance filing made on 3/14/25 in Docket No. E002/M-23-452.
26		Xcel shall conduct a Request for Information (RFI) process to assess the feasibility of its planned Non-Wires Alternatives solicitation, including the proposed "ARR split" compensation, and make a compliance filing reporting on the results of the RFI within 12 months of this order.	Chapter 8: Non-Wires Alternatives Analysis	Chapter 8: Non-Wires Alternatives Analysis pg. 18

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☐ **Public Document – Not-Public Data Has Been Excised**
☒ **Public Document**

Xcel Energy		Information Request No.	2
Docket No.:	E002/M-25-142		
Response To:	Minnesota Department of Commerce		
Requestor:	Ari Zwick, Diane Dietz, Rachel Wiedewitsch, Bhavin Pradhan, Krystal Binversie		
Date Received:	November 3, 2025		

Question:
Topic: Expenditures

Please provide the actual total Capital Expenditures (CapEx) and Operating & Maintenance Expenditures (O&M), in dollars, incurred by Xcel Energy in Minnesota by fiscal year for 2020, 2021, 2022, 2023 and 2024 in each of the following categories: distribution, transmission, and generation.

Please include:
- Capital Expenditures by Category (distribution, transmission, generation) and Year
- O&M Expenditures by Category (distribution, transmission, generation) and Year
- Annual Totals (CapEx + O&M) by Category (distribution, transmission, generation) and Year

Please also provide the capital accounts using the FERC Chart of Accounts defined as distribution, transmission and generation for each year. Provide a narrative explaining the rationale for changing the classification of any capital account for this period.

Response:
While we are providing the information available, we respectfully note several concerns regarding the scope and intent of this Information Request:

1. **Beyond the Scope of the IDP:** The Integrated Distribution Plan (IDP) is intended as a forward-looking planning document to inform stakeholders about distribution system needs and strategies. It is not designed to serve as a prudence review or a retrospective cost analysis. We are concerned that the level of detail requested, actual historical expenditures by category and associated FERC accounts, falls outside the purpose and scope of the IDP as established in Commission orders.

2. **Regulatory Process Considerations:** The requested information aligns more closely with what is typically examined in rate case proceedings or other cost recovery dockets. Those processes include comprehensive reviews of actual expenditures, prudence determinations, and cost allocations, supported by detailed testimony and workpapers. Attempting to incorporate such analysis into the IDP process risks conflating planning objectives with cost recovery mechanisms, which could create confusion and duplicate regulatory efforts.

3. **Insufficiency for Rate Impact Analysis:** If this information is intended to estimate rate impacts, it does not provide sufficient detail for that purpose. Rate impact calculations require a full set of inputs, including revenue requirements, depreciation schedules, cost of capital, tax impacts, and allocations across jurisdictions and customer classes. These elements are addressed comprehensively in rate cases, not in planning documents like the IDP.

Please see Attachment A to this response for the Capital Expenditures by Category and a breakdown of the capital accounts by FERC. See below for Table 1 regarding O&M:

Table 1
O&M Expenditures by Category

	State of Minnesota Electric Jurisdiction Net of Interchange Billings to NSPW Actual O&M Expenditures ($ in Millions)				
	2020	**2021**	**2022**	**2023**	**2024**
Distribution Operations	$85.8	$103.2	$108.1	$95.6	$111.8
Transmission	$22.16	$21.97	$20.98	$20.84	$17.40
Generation	$295.05	$297.56	$299.26	$312.21	$320.27
TOTAL	**$403.01**	**$422.73**	**$428.34**	**$428.65**	**$449.47**

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Date: November 21, 2025

Captial Expenditures for Minnesota Electric Jurisdiction

Functional Class Category	2020	2021	2022	2023	2024
Common General Plant	47,914,905	59,122,322	72,020,816	90,612,564	98,428,779
Common Intangible Plant	49,980,206	63,876,142	63,062,468	106,864,793	82,548,080
Electric Distribution Plant	269,258,368	256,036,138	372,758,944	489,460,577	655,188,188
Electric General Plant	47,957,112	84,405,699	101,902,401	159,191,001	174,148,700
Electric Hydro Production Plant	204,730	98,938	154,500	177,352	1,072,867
Electric Intangible Plant	16,211,635	42,648,486	58,727,628	37,810,982	31,558,420
Electric Nuclear Production Plant	59,564,751	85,188,733	95,235,582	159,536,149	140,679,775
Electric Other Production Plant	855,839,289	593,767,040	430,606,174	319,351,019	549,179,887
Electric Steam Production Plant	30,166,101	29,418,849	32,792,099	52,995,189	34,164,847
Electric Transmission Plant	161,654,488	192,627,875	197,508,233	293,528,822	341,288,499
Nuclear Fuel	45,576,792	89,369,390	83,289,449	127,240,619	123,218,778
Grand Total	**1,584,328,376**	**1,496,559,613**	**1,508,058,295**	**1,836,769,067**	**2,231,476,819**

Captial Expenditures for Minnesota Electric Jurisdiction

Functional Class Category	FERC Account	2020	2021	2022	2023	2024
Common General Plant	389			2,148,319	5,786,464	3,522
	390	12,983,876	17,385,525	27,173,185	24,295,301	54,106,586
	391	32,290,996	37,240,174	39,968,115	56,643,118	37,270,003
	392	876,941	2,108,317	685,946	1,464,869	1,553,316
	393	50,082	63,729	41,026	43,360	80,508
	394	1,080,999	1,785,266	1,615,704	2,172,086	5,256,441
	396	67,059	161,837	49,043	87,924	91,129
	397	518,858	318,819	301,720	100,172	54,456
	398	46,094	58,654	37,759	19,269	12,818
Common General Plant Total		**47,914,905**	**59,122,322**	**72,020,816**	**90,612,564**	**98,428,779**
Common Intangible Plant	105				19,089,000	
	303	49,980,206	63,876,142	63,062,468	87,775,793	82,548,080
Common Intangible Plant Total		**49,980,206**	**63,876,142**	**63,062,468**	**106,864,793**	**82,548,080**
Electric Distribution Plant	360	247,293	(302,617)	32,246	958,337	1,221,992
	361	3,218,087	2,941,474	4,593,635	5,910,833	6,733,639
	362	46,235,515	24,082,955	43,686,382	57,682,983	74,001,658
	364	37,126,833	40,343,434	53,044,894	65,605,486	96,902,564
	365	36,004,578	37,698,017	49,714,546	57,561,313	83,543,266
	366	52,384,052	51,045,471	61,616,122	68,689,327	90,491,945
	367	92,703,588	94,665,629	120,863,176	132,525,800	193,668,033
	368	(273,960)	(764,952)			8,514,914
	369	(36,061)	(127,897)			1,157,341
	370	400,430	1,229,158	29,685,684	90,415,099	92,700,658
	371		2,513,216	6,896,043	9,274,490	4,883,295
	373	1,248,013	2,712,250	2,626,217	836,910	1,368,882
Electric Distribution Plant Total		**269,258,368**	**256,036,138**	**372,758,944**	**489,460,577**	**655,188,188**
Electric General Plant	389	11,555	12,564,151	(48,097)	256,520	1,220,418
	390	1,449,797	4,374,700	11,146,194	50,276,428	77,332,474
	391	11,275,791	14,216,755	13,105,297	10,753,409	15,378,437
	392	10,401,126	11,924,311	21,488,084	34,421,089	28,678,800
	393	86,287	175,928	237,075	219,435	137,981
	394	5,588,967	12,458,618	17,902,424	17,140,948	10,758,334
	395	154,690	297,040	428,869	361,960	185,027
	396	2,939,226	3,142,959	5,814,777	9,994,543	9,967,793
	397	15,847,727	24,840,032	31,551,432	35,537,590	30,362,109
	398	201,945	411,205	276,348	229,079	127,327
Electric General Plant Total		**47,957,112**	**84,405,699**	**101,902,401**	**159,191,001**	**174,148,700**
Electric Hydro Production Plant	331	15,045	7,271	11,356	13,016	81,381
	332	46,606	22,370	35,151	40,683	253,922
	333	107,384	51,654	80,342	91,567	545,143
	334	34,526	16,678	25,971	29,715	176,394
	335	399	192	475	999	5,955
	336	770	773	1,203	1,371	10,070
Electric Hydro Production Plant Total		**204,730**	**98,938**	**154,500**	**177,352**	**1,072,867**
Electric Intangible Plant	105		3,592,533	3,106,969		647,838
	302	1,756,901	8,055,790	10,173,988	7,501,683	4,866,445
	303	14,454,734	31,000,163	45,446,672	30,309,299	26,044,137
Electric Intangible Plant Total		**16,211,635**	**42,648,486**	**58,727,628**	**37,810,982**	**31,558,420**
Electric Nuclear Production Plant	320			317	(137,795)	
	321	7,685,122	11,804,966	14,113,680	24,178,624	20,943,369
	322	34,608,110	46,472,221	48,471,406	75,432,694	76,203,288
	323	8,151,807	12,521,796	15,511,567	29,253,647	21,318,920
	324	6,984,099	11,070,609	12,871,148	23,635,948	17,082,490
	325	2,135,613	3,319,140	4,267,465	7,173,031	5,131,708
Electric Nuclear Production Plant Total		**59,564,751**	**85,188,733**	**95,235,582**	**159,536,149**	**140,679,775**
Electric Other Production Plant	340	651,735	(278,933)	(5,080)	2,462,279	(9,437,182)
	341	66,255,400	21,684,244	8,925,381	8,180,197	80,172,181
	342	824,988	457,620	1,003,900	924,758	965,394
	343	2,696,153	3,027,548	4,919,093	5,348,398	5,670,141
	344	672,996,110	548,667,809	382,011,857	286,859,187	309,445,575
	345	60,746,028	15,595,050	25,503,039	11,916,667	92,886,031
	346	51,669,132	4,613,701	8,236,823	2,649,173	68,301,893
	348	(258)		11,160	1,010,361	1,175,854
Electric Other Production Plant Total		**855,839,289**	**593,767,040**	**430,606,174**	**319,351,019**	**549,179,887**
Electric Steam Production Plant	310	1,325,714	171,059	56,052	(133,164)	(828,776)
	311	4,599,748	3,927,675	3,570,845	8,008,417	2,388,623
	312	17,192,755	18,043,986	17,173,521	34,864,154	20,504,979
	314	3,638,098	3,943,870	6,166,161	6,123,694	6,945,372
	315	2,460,601	2,257,761	3,133,584	2,260,448	2,368,406
	316	949,186	1,074,498	2,691,935	1,871,640	2,786,243
Electric Steam Production Plant Total		**30,166,101**	**29,418,849**	**32,792,099**	**52,995,189**	**34,164,847**
Electric Transmission Plant	350	2,434,370	2,811,123	(1,910,554)	714,859	2,537,228
	352	13,939,357	6,931,990	4,632,232	9,688,684	10,862,846
	353	66,421,580	73,415,033	65,837,560	102,995,583	121,369,915
	354	3,707,484	2,087,224	6,644,281	7,235,125	4,191,318
	355	(301,031,169)	154,356,842	1,775,373,663	(1,665,574,532)	9,814,732,159
	356	375,879,159	(49,222,713)	(1,652,168,217)	1,837,712,585	(9,613,639,147)
	357	124,539	1,095,407	(299,009)	70,553	227,581
	358	179,170	1,152,968	(665,728)	292,076	739,097
	359			64,004	393,890	267,502
Electric Transmission Plant Total		**161,654,488**	**192,627,875**	**197,508,233**	**293,528,822**	**341,288,499**
Nuclear Fuel	120	45,576,792	89,369,390	83,289,449	127,240,619	123,218,778
Nuclear Fuel Total		**45,576,792**	**89,369,390**	**83,289,449**	**127,240,619**	**123,218,778**
Grand Total		**1,584,328,376**	**1,496,559,613**	**1,508,058,295**	**1,836,769,067**	**2,231,476,819**

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Xcel Energy		Information Request No.	11
Docket No.:	E002/M-25-142		
Response To:	Minnesota Department of Commerce		
Requestor:	Adway De		
Date Received:	November 13, 2025		

Question:
Topic: Peak load
Reference(s): IDP

Please provide annual peak load jointly by Planning Division and by LoadSEER's categories (corporate energy sales and demand, electric vehicle, beneficial electrification, solar PV, battery storage, and energy efficiency) based on actual (2019-2024) and predicted (2025-2029) data. Please provide a brief explanation for what is included within each category. Please include live excel spreadsheets with the relevant data in your response.

Response:
The requested information is provided in Attachment A, which includes historical (2019–2024) and forecasted (2026–2029) annual peak load data. The forecasted data is based on the IDP Base Native scenario. The spreadsheet begins with a tab showing annual peak load by planning area, followed by a "Key" tab that explains the spatial allocation and how LoadSEER forecasting layers correspond to categories. The remaining tabs present the forecasted peak load allocations across the forecast layers modeled in LoadSEER—corporate energy sales and demand, electric vehicles, beneficial electrification, solar PV, battery storage, and energy efficiency—organized by planning division.

We note that LoadSEER categories are available only for forecasted data and are not available for historical actuals. Additionally, historic data for 2020 and 2021 is incomplete, as only approximately two-thirds of Minnesota feeders had historic peak loads recorded for those years due to the transition to the LoadSEER forecasting software. Finally, the IDP forecast begins in 2026, so year 2025 is not included in the forecast, and neither historic nor forecasted data is available for the current year.

In the Attachment, we also provide a brief explanation for what is included within the forecast layers modeled in LoadSEER:

- **Corporate Energy Sales and Demand:** includes new residential and commercial loads.
- **Electric Vehicles:** covers commercial, fleet, public, residential, and workplace charging.
- **Beneficial Electrification:** consists of residential space and water heating, commercial space and water heating, as well as miscellaneous BE business loads.
- **Solar PV:** includes commercial, community solar, and residential photovoltaic systems.
- **Battery Storage:** encompasses all forms of battery storage.
- **Energy Efficiency:** covers commercial and residential efficiency measures.

Preparer:	Meghan Tisdell
Title:	Principal Engineer
Department:	NSP Distribution Planning
Telephone:	763-493-1850
Date:	November 24, 2025

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Xcel Energy		Information Request No.	13
Docket No.:	E002/M-25-142		
Response To:	Minnesota Department of Commerce		
Requestor:	Adway De		
Date Received:	November 13, 2025		

Question:
Topic: Line Utilization
Reference(s): IDP

Please provide average annual line utilization percentage by Planning Division based on actual (2019-2024) and predicted (2025-2029) data. Please include live excel spreadsheets with the relevant data in your response.

Response:
See Attachment A, which includes the average annual utilization percentage for each Planning Division for the forecast years 2025-2029. The utilization percentage was calculated by aggregating the substation transformer hourly forecasts to the Planning Division level and taking the annual average of hourly load and dividing it by the total capacity. Note that these results differ slightly from the 2025 IDP due to recent map adjustments. LoadSEER uses a universal map adjustment layer, and updates are underway for the next forecast. A map adjustment represents a known load growth point added by our planning engineers based on new load interconnection requests. These adjustments are routinely updated in LoadSEER as requests are processed, updated, or removed.

For actual data (2019-2024), because our SCADA system lacks a hierarchy, mapping each SCADA data point would require manually identifying data points for over 400 transformers and linking them with the planning division. We estimate that it would take three months to do this compilation, aggregation, and review. We also caution against using raw SCADA data for decision-making due to potential inaccuracies caused by switching events, communication losses, outages, and other factors.

Finally, please note that annual average hourly loading is not a metric used in our planning process. Its usefulness for planning divisions is extremely limited because these divisions cover large geographic areas.

Preparer:	Joe Verbout
Title:	Manager, System Planning and
Department:	NSP Distribution Planning
Telephone:	612-399-5359
Date:	December 22, 2025

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Xcel Energy		Information Request No.	34
Docket No.:	E002/M-25-142		
Response To:	Minnesota Department of Commerce		
Requestor:	Ari Zwick, Bhavin Pradhan, Adway De, Diane Dietz		
Date Received:	December 1, 2025		

Question:
Topic: Substation and Feeder Rated Capacity and Observed Peak
Reference(s): 2025 Integrated Distribution Plan

Please provide the following information for each substation and feeder line operated by Xcel:

A. Rated Capacity
B. Technical Planning Standard Capacity that triggers a need for a capacity upgrade
C. 3-year highest peak load observed

For any system assets that do not have the available data, please summarize the number of assets by type [substation / feeder] that are affected and explain why the data is not available.

Please provide the requested data in a Microsoft Excel executable format with all links and formulae intact. If any of these links target an outside file, please provide all such additional files.

Response:
Attachment A includes the requested information for feeders and transformers in Minnesota. While we do not have data aggregated at a substation level, transformer-level data is provided. Transformers can be identified by a "_TRXX" suffix in the "EQPT ID" column.

We also assume that in this context, "Technical Planning Standard Capacity" refers to the planning limit for peak load, which is the threshold for the highest equipment loading before a capacity upgrade is required to be mitigated and a project is initiated. Since the load planning limit for substation transformers is equal to its rated capacity there are no entries in the "Capacity – Planning Threshold" column for transformer assets.

We further clarify that the planning limit for load is not the same as the planning limit for DER, called the Technical Planning Standard, which specifies the highest allowable penetration of DER on a feeder or substation transformer before upgrades are required. As described in Chapter 1 of the 2025 IDP, the load planning limit is 75 percent of rated capacity for 15 kV feeders, 50 percent of rated capacity for 25 and 35 kV feeders, and 100 percent of rated capacity for substation transformers. By comparison, the Technical Planning Standard, or the planning limit for DER, is the same for both feeders and substation transformers, and is defined as 80 percent of the rated capacity plus the daytime minimum load.

There are 37 assets for which complete information is unavailable. This may be due to one of two factors:

- The asset does not have Supervisory Control and Data Acquisition (SCADA) capabilities, so interval demand data is not available
- The asset serves solely as contingency support and does not have a system-normal load

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Preparer:	Joe Verbout
Title:	Manager, System Planning and
Department:	NSP Distribution Planning
Telephone:	612-399-5359
Date:	December 22, 2025

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Xcel Energy		Information Request No.	2
Docket No.:	E002/M-25-142		
Response To:	Minnesota Department of Commerce		
Requestor:	Ari Zwick, Diane Dietz, Rachel Wiedewitsch, Bhavin Pradhan, Krystal Binversie		
Date Received:	November 3, 2025		

Question:
Topic: Expenditures

Please provide the actual total Capital Expenditures (CapEx) and Operating & Maintenance Expenditures (O&M), in dollars, incurred by Xcel Energy in Minnesota by fiscal year for 2020, 2021, 2022, 2023 and 2024 in each of the following categories: distribution, transmission, and generation.

Please include:
- Capital Expenditures by Category (distribution, transmission, generation) and Year
- O&M Expenditures by Category (distribution, transmission, generation) and Year
- Annual Totals (CapEx + O&M) by Category (distribution, transmission, generation) and Year

Please also provide the capital accounts using the FERC Chart of Accounts defined as distribution, transmission and generation for each year. Provide a narrative explaining the rationale for changing the classification of any capital account for this period.

Response:
While we are providing the information available, we respectfully note several concerns regarding the scope and intent of this Information Request:

1. **Beyond the Scope of the IDP:** The Integrated Distribution Plan (IDP) is intended as a forward-looking planning document to inform stakeholders about distribution system needs and strategies. It is not designed to serve as a prudence review or a retrospective cost analysis. We are concerned that the level of detail requested, actual historical expenditures by category and associated FERC accounts, falls outside the purpose and scope of the IDP as established in Commission orders.

2. **Regulatory Process Considerations:** The requested information aligns more closely with what is typically examined in rate case proceedings or other cost recovery dockets. Those processes include comprehensive reviews of actual expenditures, prudence determinations, and cost allocations, supported by detailed testimony and workpapers. Attempting to incorporate such analysis into the IDP process risks conflating planning objectives with cost recovery mechanisms, which could create confusion and duplicate regulatory efforts.

3. **Insufficiency for Rate Impact Analysis:** If this information is intended to estimate rate impacts, it does not provide sufficient detail for that purpose. Rate impact calculations require a full set of inputs, including revenue requirements, depreciation schedules, cost of capital, tax impacts, and allocations across jurisdictions and customer classes. These elements are addressed comprehensively in rate cases, not in planning documents like the IDP.

Please see Attachment A to this response for the Capital Expenditures by Category and a breakdown of the capital accounts by FERC. See below for Table 1 regarding O&M:

Table 1
O&M Expenditures by Category

	State of Minnesota Electric Jurisdiction Net of Interchange Billings to NSPW Actual O&M Expenditures ($ in Millions)				
	2020	**2021**	**2022**	**2023**	**2024**
Distribution Operations	$85.8	$103.2	$108.1	$95.6	$111.8
Transmission	$22.16	$21.97	$20.98	$20.84	$17.40
Generation	$295.05	$297.56	$299.26	$312.21	$320.27
TOTAL	**$403.01**	**$422.73**	**$428.34**	**$428.65**	**$449.47**

Preparer: Luke Hennen | Nik Biswas
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Preparer: Mary Pope
Title: Principal Rate Analyst
Department: Revenue Requirements
Telephone: 612-330-6574
Date: November 21, 2025

Captial Expenditures for Minnesota Electric Jurisdiction

Functional Class Category	2020	2021	2022	2023	2024
Common General Plant	47,914,905	59,122,322	72,020,816	90,612,564	98,428,779
Common Intangible Plant	49,980,206	63,876,142	63,062,468	106,864,793	82,548,080
Electric Distribution Plant	269,258,368	256,036,138	372,758,944	489,460,577	655,188,188
Electric General Plant	47,957,112	84,405,699	101,902,401	159,191,001	174,148,700
Electric Hydro Production Plant	204,730	98,938	154,500	177,352	1,072,867
Electric Intangible Plant	16,211,635	42,648,486	58,727,628	37,810,982	31,558,420
Electric Nuclear Production Plant	59,564,751	85,188,733	95,235,582	159,536,149	140,679,775
Electric Other Production Plant	855,839,289	593,767,040	430,606,174	319,351,019	549,179,887
Electric Steam Production Plant	30,166,101	29,418,849	32,792,099	52,995,189	34,164,847
Electric Transmission Plant	161,654,488	192,627,875	197,508,233	293,528,822	341,288,499
Nuclear Fuel	45,576,792	89,369,390	83,289,449	127,240,619	123,218,778
Grand Total	**1,584,328,376**	**1,496,559,613**	**1,508,058,295**	**1,836,769,067**	**2,231,476,819**

Captial Expenditures for Minnesota Electric Jurisdiction

Functional Class Category	FERC Account	2020	2021	2022	2023	2024
Common General Plant	389			2,148,319	5,786,464	3,522
	390	12,983,876	17,385,525	27,173,185	24,295,301	54,106,586
	391	32,290,996	37,240,174	39,968,115	56,643,118	37,270,003
	392	876,941	2,108,317	685,946	1,464,869	1,553,316
	393	50,082	63,729	41,026	43,360	80,508
	394	1,080,999	1,785,266	1,615,704	2,172,086	5,256,441
	396	67,059	161,837	49,043	87,924	91,129
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Common Intangible Plant Total		**49,980,206**	**63,876,142**	**63,062,468**	**106,864,793**	**82,548,080**
Electric Distribution Plant	360	247,293	(302,617)	32,246	958,337	1,221,992
	361	3,218,087	2,941,474	4,593,635	5,910,833	6,733,639
	362	46,235,515	24,082,955	43,686,382	57,682,983	74,001,658
	364	37,126,833	40,343,434	53,044,894	65,605,486	96,902,564
	365	36,004,578	37,698,017	49,714,546	57,561,313	83,543,266
	366	52,384,052	51,045,471	61,616,122	68,689,327	90,491,945
	367	92,703,588	94,665,629	120,863,176	132,525,800	193,668,033
	368	(273,960)	(764,952)			8,514,914
	369	(36,061)	(127,897)			1,157,341
	370	400,430	1,229,158	29,685,684	90,415,099	92,700,658
	371		2,513,216	6,896,043	9,274,490	4,883,295
	373	1,248,013	2,712,250	2,626,217	836,910	1,368,882
Electric Distribution Plant Total		**269,258,368**	**256,036,138**	**372,758,944**	**489,460,577**	**655,188,188**
Electric General Plant	389	11,555	12,564,151	(48,097)	256,520	1,220,418
	390	1,449,797	4,374,700	11,146,194	50,276,428	77,332,474
	391	11,275,791	14,216,755	13,105,297	10,753,409	15,378,437
	392	10,401,126	11,924,311	21,488,084	34,421,089	28,678,800
	393	86,287	175,928	237,075	219,435	137,981
	394	5,588,967	12,458,618	17,902,424	17,140,948	10,758,334
	395	154,690	297,040	428,869	361,960	185,027
	396	2,939,226	3,142,959	5,814,777	9,994,543	9,967,793
	397	15,847,727	24,840,032	31,551,432	35,537,590	30,362,109
	398	201,945	411,205	276,348	229,079	127,327
Electric General Plant Total		**47,957,112**	**84,405,699**	**101,902,401**	**159,191,001**	**174,148,700**
Electric Hydro Production Plant	331	15,045	7,271	11,356	13,016	81,381
	332	46,606	22,370	35,151	40,683	253,922
	333	107,384	51,654	80,342	91,567	545,143
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	335	399	192	475	999	5,955
	336	770	773	1,203	1,371	10,070
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Electric Intangible Plant	105		3,592,533	3,106,969		647,838
	302	1,756,901	8,055,790	10,173,988	7,501,683	4,866,445
	303	14,454,734	31,000,163	45,446,672	30,309,299	26,044,137
Electric Intangible Plant Total		**16,211,635**	**42,648,486**	**58,727,628**	**37,810,982**	**31,558,420**
Electric Nuclear Production Plant	320			317	(137,795)	
	321	7,685,122	11,804,966	14,113,680	24,178,624	20,943,369
	322	34,608,110	46,472,221	48,471,406	75,432,694	76,203,288
	323	8,151,807	12,521,796	15,511,567	29,253,647	21,318,920
	324	6,984,099	11,070,609	12,871,148	23,635,948	17,082,490
	325	2,135,613	3,319,140	4,267,465	7,173,031	5,131,708
Electric Nuclear Production Plant Total		**59,564,751**	**85,188,733**	**95,235,582**	**159,536,149**	**140,679,775**
Electric Other Production Plant	340	651,735	(278,933)	(5,080)	2,462,279	(9,437,182)
	341	66,255,400	21,684,244	8,925,381	8,180,197	80,172,181
	342	824,988	457,620	1,003,900	924,758	965,394
	343	2,696,153	3,027,548	4,919,093	5,348,398	5,670,141
	344	672,996,110	548,667,809	382,011,857	286,859,187	309,445,575
	345	60,746,028	15,595,050	25,503,039	11,916,667	92,886,031
	346	51,669,132	4,613,701	8,236,823	2,649,173	68,301,893
	348	(258)		11,160	1,010,361	1,175,854
Electric Other Production Plant Total		**855,839,289**	**593,767,040**	**430,606,174**	**319,351,019**	**549,179,887**
Electric Steam Production Plant	310	1,325,714	171,059	56,052	(133,164)	(828,776)
	311	4,599,748	3,927,675	3,570,845	8,008,417	2,388,623
	312	17,192,755	18,043,986	17,173,521	34,864,154	20,504,979
	314	3,638,098	3,943,870	6,166,161	6,123,694	6,945,372
	315	2,460,601	2,257,761	3,133,584	2,260,448	2,368,406
	316	949,186	1,074,498	2,691,935	1,871,640	2,786,243
Electric Steam Production Plant Total		**30,166,101**	**29,418,849**	**32,792,099**	**52,995,189**	**34,164,847**
Electric Transmission Plant	350	2,434,370	2,811,123	(1,910,554)	714,859	2,537,228
	352	13,939,357	6,931,990	4,632,232	9,688,684	10,862,846
	353	66,421,580	73,415,033	65,837,560	102,995,583	121,369,915
	354	3,707,484	2,087,224	6,644,281	7,235,125	4,191,318
	355	(301,031,169)	154,356,842	1,775,373,663	(1,665,574,532)	9,814,732,159
	356	375,879,159	(49,222,713)	(1,652,168,217)	1,837,712,585	(9,613,639,147)
	357	124,539	1,095,407	(299,009)	70,553	227,581
	358	179,170	1,152,968	(665,728)	292,076	739,097
	359			64,004	393,890	267,502
Electric Transmission Plant Total		**161,654,488**	**192,627,875**	**197,508,233**	**293,528,822**	**341,288,499**
Nuclear Fuel	120	45,576,792	89,369,390	83,289,449	127,240,619	123,218,778
Nuclear Fuel Total		**45,576,792**	**89,369,390**	**83,289,449**	**127,240,619**	**123,218,778**
Grand Total		**1,584,328,376**	**1,496,559,613**	**1,508,058,295**	**1,836,769,067**	**2,231,476,819**

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Xcel Energy		Information Request No.	4
Docket No.:	E002/M-25-142		
Response To:	Minnesota Department of Commerce		
Requestor:	Adway De		
Date Received:	November 13, 2025		

Question:
Topic: Planning Divisions
Reference(s): IDP

Please describe how the Company defines and constructs "Planning Divisions" and how the Company uses these geographic areas to record its distribution system spending.

Response:
The Company's Minnesota service territory is divided into 11 planning divisions. These divisions are primarily based on the customers served by a subset of electric assets and generally align with service center territories, though some overlap occurs when assets (e.g. feeders) cross service center boundaries. In certain cases, multiple service centers are grouped together into one planning division for efficiency.

Each planning division is assigned a unique location code, which is used to track and record some of the distribution system spending for that area. For projects, programs, and blankets that span multiple divisions, a separate location code is applied.

Some planning divisions in Minnesota include assets that are physically located on the Minnesota side of the state border but are operationally serviced from our North Dakota and South Dakota service centers.

The Minnesota planning divisions are:

- Edina
- Maple Grove
- Minneapolis
- Minnetonka
- Newport
- North Dakota (MN)
- Northwest
- South Dakota (MN)

- Southeast
- St. Paul
- White Bear Lake

Preparer:	Joe Verbout
Title:	Manager, System Planning and Strategy
Department:	NSP Distribution Planning
Telephone:	612-399-5359
Date:	November 24, 2025

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Xcel Energy		Information Request No.	6
Docket No.:	E002/M-25-142		
Response To:	Minnesota Department of Commerce		
Requestor:	Adway De		
Date Received:	November 13, 2025		

Question:
Topic: Annual Spending
Reference(s): IDP

Please provide a breakdown of the annual spending per internal budget category by Planning Division for actual (2019-2024) and predicted (2025-2029) expenses. If there are some expenses that cannot be allocated to a specific Planning Division, please create a residual placeholder. Please include live excel spreadsheets with the relevant data in your response.

Response:
Xcel Energy objects to this Information Request as unduly burdensome. Xcel Energy does not maintain the requested 2019-2023 data in a readily accessible and usable format. Compiling such data would be overly burdensome compared to the relative value of the information produced. Subject to and without waiving this objection, Xcel Energy responds as follows:

Notwithstanding the objection, please see Attachment A, which provides historical and forecasted discrete expenditures for each planning division, grouped by the Company's internal budget categories. Each planning division is assigned a unique location code, which is used to track and record certain distribution system spending within that area. The location code for an individual planning division is generally used only for discrete projects, as these projects often involve work at a single location within one planning division. In contrast, programs and blankets include work that spans multiple planning divisions. For these, a location code is used that represents either the entire state of Minnesota or Northern States Power Minnesota (NSPM).

Additionally, please note that in some cases there are multiple location codes for the same planning division. These represent situations in which multiple operational service centers are grouped into one planning division for planning efficiency.

Preparer:	Viennie Phommatha
Title:	Manager, Investment Delivery
Department:	Distribution Electric Engineering
Email:	viennie.phommatha@xcelenergy.com
Date:	November 24, 2025

Northern States Power Company

Docket No. E002/M-25-142
DOC IR No. 6
Attachment A - Page 1 of 1

IR6 Discrete L2s by Location

Capital Budget Category	LOC	LOC Description	2024	2025	2026	2027	2028	2029	2030	Grand Total
Asset Health & Reliability	103	NSPM Allocate	4,187							4,187
	114	Minnesota	23,612							23,612
	141	Minneapolis	121,469	8,212,758	8,300,002	14,825,002	11,325,002	5,999,999	1,499,999	50,284,231
	142	Minnetonka	2,721,812	174,646						2,896,458
	143	Edina	600,346	1,032,512	1,725,004					3,357,862
	144	Southeast	6,791,184	15,793,808	11,630,008	11,194,997	7,105,003	22,649,995		75,164,995
	146	North Dakota (MN)	3,337,543	2,616,905						5,954,449
	147	Maple Grove	1,566,172	194,544						1,760,716
	150	Newport	145,486	1,625,213			9,100,000			10,870,699
	151	St Paul	24,218,709	18,873,243	17,181,997	6,000,001	5,189,999	7,949,997		79,413,946
	152	South Dakota (MN)	3,705,746	3,679,934		3,500,002	3,600,001	5,000,002		19,485,684
	154	Northwest	5,093,179	3,746,919	2,175,005	26,860,424	13,499,997	5,999,998		57,375,523
	156	White Bear Lake	708,590	435,645						1,144,235
	158	Southeast	56,831	14,656,211	2,120,002					16,833,044
Asset Health & Reliability Total			**49,094,867**	**71,042,338**	**43,132,018**	**62,380,426**	**49,820,002**	**47,599,991**	**1,499,999**	**324,569,641**
Capacity	141	Minneapolis	2,140,731	6,065,018	28,879,997	10,000,005	5,000,000	30,400,005	19,500,997	101,986,753
	142	Minnetonka			909,999		9,330,001	2,150,000	7,800,004	20,190,004
	143	Edina	6,533,073	4,125,081	12,950,011	7,630,000	2,049,999	35,580,002	5,546,999	74,415,165
	144	Faribault	3,293,708	22,336,450	38,552,907	32,757,224	32,513,440	58,280,010	34,600,005	222,333,744
	146	North Dakota (MN)	17,213	349			100,001	2,300,000		2,417,563
	147	Maple Grove	5,912,925	1,728,939	23,135,000	27,199,998	12,499,996	12,450,005	47,330,006	130,256,869
	150	Newport	2,093,445	11,237,084	30,907,165	7,868,010	26,779,746	11,562,999	22,466,003	112,914,452
	151	St Paul	3,851,772	3,057,463	16,869,002	12,599,997		5,904,004	34,799,998	77,082,236
	152	South Dakota (MN)	70,970	733,000	3,450,002	4,200,000	5,999,996			14,453,968
	154	Northwest	3,149,444	11,924,473	27,232,004	82,534,570	39,006,002	47,200,002	24,399,998	235,446,493
	156	White Bear Lake	845,088	2,672,152	22,182,877	7,275,003	10,769,997	43,915,008	8,349,998	96,010,123
	158	Southeast		(5,941)						(5,941)
Capacity Total			**27,908,369**	**63,880,010**	**205,068,964**	**192,064,807**	**144,049,178**	**249,742,035**	**204,794,008**	**1,087,507,371**
Fleet, Tools & Comm	114	Minnesota	22,644	1,029,959	6,580					1,059,184
	141	Minneapolis	116,092	754,986	199,999			550,000	500,999	2,122,076
	142	Minnetonka					1,000,000			1,000,000
	144	Southeast	241,742	948,139	2,987,809	1,588,871	800,003	1,800,000	1,100,002	9,466,566
	147	Maple Grove					175,002		400,001	575,003
	150	Newport					292,001			292,001
	151	St Paul	148,209	125,880	50,000	50,000			500,000	874,089
	154	Northwest			607,002	4,281,005	1,432,997	900,000	1,300,001	8,521,005
	156	White Bear Lake						600,000		600,000
	158	Southeast		17,354						17,354
Fleet, Tools & Comm Total			**528,686**	**2,876,319**	**3,851,390**	**5,919,876**	**3,700,003**	**3,850,000**	**3,801,003**	**24,527,278**
Mandates	141	Minneapolis	12,181,273	3,431,228	3,149,999					18,762,500
	142	Minnetonka	3,002,536	1,058,682	1,125,001					5,186,218
	143	Edina	-	33,191			560,000			593,191
	144	Southeast	288,498	3,389,679	500,000					4,178,177
	147	Maple Grove	56,019	1,091,936	650,002					1,797,957
	150	Newport	834,888	1,535,466						2,370,354
	151	St Paul	813,306	5,097,428	4,300,001					10,210,735
	154	Northwest	20,505	1,088,633	135,000					1,244,138
	156	White Bear Lake	619,266	5,079						624,345
	157	White Bear Lake	6,456							6,456
	158	Southeast		694,047	435,001					1,129,048
Mandates Total			**17,822,748**	**17,425,368**	**10,295,004**	**-**	**560,000**	**-**	**-**	**46,103,120**
New Business	142	Minnetonka	148,273	98,006	263,000					509,279
	143	Edina		1,000	160,001					161,001
	144	Southeast	31,416	165	110,002					141,582
	147	Maple Grove	670,072	199,464						869,536
	150	Newport	4,477,681	3,808,180	3,250,002		4,800,000			16,335,863
	151	St Paul	42,255	90,167	184,999					317,422
	154	Northwest	591,958	984,696	235,001					1,811,655
	156	White Bear Lake	480,580	748,175						1,228,754
	157	White Bear Lake	331,769							331,769
New Business Total			**6,774,003**	**5,929,853**	**4,203,005**	**-**	**4,800,000**	**-**	**-**	**21,706,860**
WILDFIRE	114	Minnesota		85,152,625	150,995,999	131,582,998	56,899,998	41,200,000	41,200,000	507,031,620
WILDFIRE Total			**-**	**85,152,625**	**150,995,999**	**131,582,998**	**56,899,998**	**41,200,000**	**41,200,000**	**507,031,620**
Grand Total			**102,128,673**	**246,306,512**	**417,546,380**	**391,948,107**	**259,829,181**	**342,392,026**	**251,295,010**	**2,011,445,890**

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Xcel Energy		Information Request No.	7
Docket No.:	E002/M-25-142		
Response To:	Minnesota Department of Commerce		
Requestor:	Adway De		
Date Received:	November 13, 2025		

Question:
Topic: Planning Division Map
Reference(s): IDP

Please provide a shapefile of the Planning Divisions that is readable in ArcGIS or related software. If this is not available, provide this information as a pdf map.

Response:
Please see Attachment A, which is a .kmz shapefile of the Planning Divisions. The shapefile will need to be opened in a Geospatial Information System or other tool that can view .kmz files to access.

Note that the polygons in the shapefile represent the approximate geographic boundaries of the planning divisions. The planning divisions are based on the customers served by a subset of electric assets, and do not align with governmental or other geographic boundaries. Some assets such as feeders may be planned within one planning division but provide service to some customers within the polygon of an adjacent planning division. Further, the planning division polygons do not perfectly align with our service territory – the Company does not provide electric service to all parcels within the planning division polygons.

Preparer:	Brian Monson
Title:	Manager, Regulatory Affairs
Department:	NSPM Regulatory
Telephone:	763-493-1811
Date:	November 24, 2025

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Xcel Energy		Information Request No.	8
Docket No.:	E002/M-25-142		
Response To:	Minnesota Department of Commerce		
Requestor:	Adway De		
Date Received:	November 13, 2025		

Question:
Topic: Feeder Planning Limit
Reference(s): IDP

Please provide the annual number of feeders that exceed the relevant capacity planning limit by Planning Division based on actual (2019-2024) and predicted (2025-2029) data. Please include live excel spreadsheets with the relevant data in your response.

Response:
Please see Attachment A for the annual number of feeders exceeding their applicable planning limit. Two percentage thresholds are listed as applicable feeder planning limits in the attachment – 75% of rated capacity for 15kV and 50% of rated capacity for 25 and 35kV feeders (as described in IDP Chapter 1, Section IV Risk Analysis).

We note that in 2020 and 2021, only approximately two-thirds of Minnesota feeders had historic peak data recorded. This was because the distribution planning team was in the process of implementing the new forecasting software, LoadSEER, which disrupted our annual process of recording historic peak loads in those years. Additionally, the year 2025 is excluded because the Integrated Distribution Plan (IDP) forecast begins in 2026 and historic peaks have not yet been recorded for 2025. As a result, neither historic nor forecasted data is available for the current year (2025).

Preparer:	Meghan Tisdell
Title:	Principal Engineer
Department:	NSP Distribution Planning
Telephone:	763-493-1850
Date:	November 24, 2025

Northern States Power Company

	2019		2020		2021		2022		2023		2024		2026		2027		2028		2029	
	>= 75%	>=50%	>= 75%	>=50%	>= 75%	>=50%	>= 75%	>=50%	>= 75%	>=50%	>= 75%	>=50%	>= 75%	>=50%	>= 75%	>=50%	>= 75%	>=50%	>= 75%	>=50%
Edina - 143	30	3	37	3	36	2	32	2	36	2	38	2	48	2	49	2	50	2	51	2
Maple Grove - 147	24	5	20	4	31	5	20	4	21	4	18	4	38	7	40	7	40	7	40	7
Minneapolis - 141	71	1	50	1	69	0	64	1	71	1	65	0	86	1	87	1	89	1	93	1
Minnetonka - 142	4	2	3	2	8	2	6	1	8	1	5	2	6	1	7	1	7	1	7	1
Newport - 150	21	8	9	3	10	4	28	6	28	8	33	7	35	9	35	9	35	9	36	9
Northwest - 154	15	16	0	2	1	4	19	18	23	20	18	16	23	16	27	17	27	17	27	18
South Dakota/Sioux Falls - 152	1	2	0	1	0	1	0	1	0	1	0	1	1	1	1	1	1	1	1	1
Southeast - 144	37	6	0	0	0	0	28	6	41	6	45	5	44	6	46	6	46	6	48	6
St Paul - 151	24		1		3		20		27		27		27		28		29		30	
White Bear Lake - 156	15	5	17	5	23	6	21	6	22	5	18	5	29	5	30	5	31	5	31	6
Total Minnesota	**242**	**48**	**137**	**21**	**181**	**24**	**238**	**45**	**277**	**48**	**267**	**42**	**337**	**48**	**350**	**49**	**355**	**49**	**364**	**51**

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Xcel Energy		Information Request No.	14
Docket No.:	E002/M-25-142		
Response To:	Minnesota Department of Commerce		
Requestor:	Krystal Binversie		
Date Received:	November 18, 2025		

Question:
Topic: NWA
Reference(s):
Please explain Xcel's definition and understanding of what is considered a non-wire alternative.

Response:
Non-Wires Alternatives (NWA) are the strategic deployment of distributed energy resources, flexible demands, communication, and controls, and/or the aggregation of technologies intended to cost-effectively defer or avoid the need for the traditional mitigation solutions.

Preparer:	Leo Khong
Title:	Engineer
Department:	NSP Distribution Planning
Email:	leo.l.khong@xcelenergy.com
Date:	December 1, 2025

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Xcel Energy		Information Request No.	31
Docket No.:	E002/M-25-142		
Response To:	Minnesota Department of Commerce		
Requestor:	Ari Zwick, Bhavin Pradhan, Adway De, Diane Dietz		
Date Received:	December 1, 2025		

Question:
Topic: Cause of Outages
Reference(s): 2025 Integrated Distribution Plan

Please provide a list the following data for 2023 and 2024:

A. Each outage event on the distribution system
B. Location of the outage
C. Cause of the outage
D. Estimated customer minutes of outages experienced

Please provide the requested data in a Microsoft Excel executable format with all links and formulae intact. If any of these links target an outside file, please provide all such additional files.

Response:
Please see Attachment A for the list as described above.

Attachment A is marked "Not-Public" in its entirety as it contains information the Company considers to be security information as defined by Minn. Stat. § 13.37(1)(a). The public disclosure or use of this information creates an unacceptable risk because those who want to disrupt the electrical grid for political or other reasons may learn which facilities to target to create the greatest disruption. The Company takes efforts to protect this information from public disclosure. Thus, Xcel Energy excises this information as protected data pursuant to Minn. Rule 7829.0500.

1. **Nature of the Material:** Security Data
2. **Author(s):** Jason Volesky
3. **Importance:** Contains not-public, proprietary and security information.
4. **Data the Information was Prepared:** December 2025

Preparer:	Jason Volesky
Title:	Principal Engineer
Department:	Electric Distribution System
Telephone:	303-285-6474
Date:	December 22, 2025

Attachment A is marked:

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Attachment A is marked "Not-Public" in its entirety as it contains information the Company considers to be security information as defined by Minn. Stat. § 13.37(1)(a). The public disclosure or use of this information creates an unacceptable risk because those who want to disrupt the electrical grid for political or other reasons may learn which facilities to target to create the greatest disruption. The Company takes efforts to protect this information from public disclosure. Thus, Xcel Energy excises this information as protected data pursuant to Minn. Rule 7829.0500.

1. **Nature of the Material:** Security Data
2. **Author(s):** Jason Volesky
3. **Importance:** Contains not-public, proprietary and security information.
4. **Data the Information was Prepared:** December 2025

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Xcel Energy		Information Request No.	32
Docket No.:	E002/M-25-142		
Response To:	Minnesota Department of Commerce		
Requestor:	Ari Zwick, Bhavin Pradhan, Adway De, Diane Dietz		
Date Received:	December 1, 2025		

Question:
Topic: Actual Distribution Customer Energy Sales
Reference(s): 2025 Integrated Distribution Plan

Please provide the actual 2018-2024 energy sales to Xcel's Minnesota retail customers that are served at the distribution level or at a cost of service that is tied to distribution charges. To elaborate on the cost of service component, please include sales to any transmission-level customers whose rates include distribution cost allocation.

Response:
The table below contains actual energy sales from 2018-2024 to the Company's Minnesota retail customers served at the distribution level.

Table 1
MN Retail Energy Sales (MWh) from 2018-2024- Distribution

2018	2019	2020	2021	2022	2023	2024
28,061,311	27,015,065	26,248,539	26,963,765	27,002,165	26,744,916	25,860,235

To calculate these sales, we adjusted total actual retail sales by excluding sales to any Transmission-Transformed and Transmission-Untransformed customers. These customers are allocated certain meter costs, which may be considered a "distribution cost," but their energy sales are not included in the distribution level totals shown above.

Preparer:	Benjamin Levine
Title:	Sr. Energy Forecasting Analyst
Department:	Load Forecasting and Analysis
Email:	benjamin.s.levine@xcelenergy.com
Date:	December 22, 2025

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Xcel Energy		Information Request No.	33
Docket No.:	E002/M-25-142		
Response To:	Minnesota Department of Commerce		
Requestor:	Ari Zwick, Bhavin Pradhan, Adway De, Diane Dietz		
Date Received:	December 1, 2025		

Question:
Topic: Forecasted Distribution Customer Energy Sales
Reference(s): 2025 Integrated Distribution Plan

Please provide the forecasted 2025-2030 energy sales to Xcel's Minnesota retail customers that are served at the distribution level or at a cost of service that is tied to distribution charges. To elaborate on the cost of service component, please include sales to any transmission-level customers whose rates include distribution cost allocation.

Response:
The table below shows forecasted energy sales for 2025-2030 to the Company's Minnesota retail customers served at the distribution level.

Table 1
MN Retail Energy Sales (MWh) from 2018-2024- Distribution

2025	2026	2027	2028	2029	2030
26,181,800	26,428,509	26,448,803	26,744,019	26,901,643	27,046,092

To calculate these figures, we adjusted total projected retail sales by excluding forecasted sales to Transmission-Transformed and Transmission-Untransformed customers. These customers are allocated certain meter costs, which may be considered a "distribution cost," but their energy sales are not included in the distribution-level totals shown above.

Preparer:	Benjamin Levine
Title:	Sr. Energy Forecasting Analyst
Department:	Load Forecasting and Analysis
Email:	benjamin.s.levine@xcelenergy.com
Date:	December 22, 2025

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Xcel Energy Information Request No. 37
Docket No.: E002/M-25-142
Response To: Minnesota Department of Commerce
Requestor: Ari Zwick, Bhavin Pradhan, Adway De, Diane Dietz
Date Received: December 1, 2025

Question:
Topic: Budget Data
Reference(s): IDP Filing – Chapter 6 Distribution Financial Information

Provide the actual expenditures for Xcel's internal budget categories (i.e. labor, materials and commodities, outside services, transportation, other, operational credits, employee expenses) for the years 2018 and 2019.

Response:
Please see Table 1 and Table 2 below:

Table 1
2018 and 2019 Actual Distribution Electric Capital Expenditures by Internal Budget Categories (Dollars in Millions)

Major Category	2018	2019
Asset Health & Reliability	$99.7	$95.3
Capacity	$13.6	$21.6
Electric Vehicles	($15.5)	($0.2)
Fleet, Tools & Comm	$11.4	$11.8
Mandates	$28.9	$39.3
New Business	$66.3	$55.2
Wildfire	0	0
AGIS	$0.4	$7.2
TOTAL	$204.9	$230.3

Table 2
Actual Historical Distribution O&M Costs by Cost Element – MN Electric
2018-2019 (Millions)

	2018	2019
Labor	50.4	46.4
Materials and Commodities	8.5	7.4
Outside Services	51.2	47.7
Transportation	2.7	9.2
Other	2.4	0.4
Operational Credits	(13.4)	(12.9)
Employee Expenses	2.8	2.5
TOTAL	**104.5**	**100.7**

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Date:	December 22, 2025	

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Xcel Energy		Information Request No.	39
Docket No.:	E002/M-25-142		
Response To:	Minnesota Department of Commerce		
Requestor:	Ari Zwick, Diane Dietz, Rachel Wiedewitsch, Bhavin Pradhan, Krystal Binversie		
Date Received:	December 17, 2025		

Question:
Topic: Wildfire Mitigation Budget
Reference(s): Department Witness Borden Testimony Docket No. E002/GR-24-320

In its IDP, the Company states at its footnote 14, referencing its Table 2-3 "Wildfire Expenditures (2025-2030)":

> *Table 2-3 presents the most current wildfire expenditures,* ***which are also included in the rate case****. These figures differ slightly from the wildfire allocations in our five-year capital budget because they were captured at different points in time. The capital budget reflects our July 2025 budget load, which has not yet been trued up.*[1]

In Xcel's ongoing rate case, Department Witness Borden recommends several changes to Xcel's Wildfire budget to scale back the proposal to focus on the highest risk portions of Xcel's territory and to collect data on the most effective mitigation measures.[2]

1. Please provide a revised wildfire mitigation budget reflecting the recommendations of Department Witness Borden in the Company's ongoing rate case.
2. Please provide a discussion of how the revisions proposed by Department Witness Borden impact the Company's wildfire mitigation plans in the IDP.

[1] *In the Matter of Xcel Energy's 2025 Integrated Distribution Plan*, Xcel Energy, October 31, 2025, Docket No. E002/M-25-142, (eDockets) 202510-224538-01, at pdf 161.
[2] *In the Matter of the Application of Xcel Energy, for Authority to Increase Rates for Electric Service in Minnesota,* Surrebuttal Testimony and Attachments of Eric Borden, Department, November 25, 2025, Docket No. E002/GR-24-320, (eDockets) 202511-225277-03, at 29-30.

Response:
The Company is not in a position to provide a revised wildfire mitigation budget or an analysis of the impact of Department Witness Borden's recommendations because the wildfire mitigation budget in the ongoing rate case has not yet been finalized. Any modifications resulting from the ongoing rate case should be addressed within that proceeding. The IDP is not updated to reflect developments in other dockets. This approach is consistent with Commission expectations that the IDP serve as a planning document rather than a dynamic record of evolving budgets.

Additionally, the requested information falls outside the scope and purpose of the IDP. The IDP is intended to outline anticipated investments and strategies based on the best available information at the time of filing, enabling stakeholders to understand the Company's long-term vision and priorities. The wildfire expenditure figures included in the 2025 IDP reflected the most current information available at the time of filing and are intended to provide a planning snapshot to guide long-term distribution system planning.

The Company remains committed to transparency and collaboration with stakeholders. Accordingly, any approved changes from the rate case will be incorporated into the wildfire expenditure section of the next IDP filing, ensuring alignment with Commission decisions and providing stakeholders with updated information for future planning discussions.

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Xcel Energy		Information Request No.	45
Docket No.:	E002/M-25-142		
Response To:	Minnesota Department of Commerce		
Requestor:	Ari Zwick, Bhavin Pradhan, Adway De, Krystal Binversie		
Date Received:	December 18, 2025		

Question:
Topic: Value of Customer Minutes of Outage
Reference(s): IDP Chapter 2, Page 14

Xcel states:
Using the Interruption Cost Estimate (ICE) tool developed by Lawrence Berkeley National Laboratory (LNBL), the Company estimates an average customer value of $3.05 per minute of avoided interruption. This metric allows for a direct comparison between the reliability benefits of undergrounding and the associated customer costs. [citation omitted]

Regarding the $3.05 per minute of avoided interruption (the value) please describe:
1. The methodology that Xcel used to derive the value.
2. If the value uses damage values that are specific to Minnesota, or if the damage value represents a national value.
3. The assumed annual customer minutes of outage for each customer class used to obtain the value.
4. The assumed share of residential, commercial, and industrial, and any other customer classes used to determine the value.
5. The value of an avoided customer minute of outage for each customer class used to obtain the value.
6. How the customer class share in 4. can be translated to the percentage of residential, commercial, and industrial customers listed in Attachment L – Circuit Table in Docket No. E002/M-25-27.
7. How the customer class value in 5. can be adjusted to fit the customer class share in 6.

Response:
1. The Company utilizes the LBNL ICE Calculator v2 (ICE v2) to calculate a dollar value amount per minute of avoided interruption for each state in its service territory. Documentation for the ICE v2 can be found at

icecalculator.com/documents. More information is also provided in Attachment A, which is submitted as a live spreadsheet.

The methodology includes the following steps:

a. The Company first enters state-specific demographic data into ICE v2:
    i. Number of Residential Customers
    ii. Number of Non-Residential Customers
    iii. Annual kWh usage for Residential and Non-Residential Customers
b. ICE v2 applies LNBL default assumptions for the following:
    i. Residential customer distribution by annual income
    ii. Residential backup generation percentage
    iii. Residential work-from-home percentage
    iv. Non-residential industry mix
    v. Seasonal (winter/summer) and day-type (weekday/weekend) interruption percentages
    vi. Economic Characteristics of Average Household Income (Residential) and GDP per Non-Residential Customer
c. The Company then enters state-specific reliability data into the model:
    i. 5 Year Average SAIFI (System Average Interruption Frequency Index)
    ii. 5 Year Average SAIDI (System Average Interruption Duration Index)
d. The ICE v2 model outputs state-level reliability cost metrics: Cost per Customer Event (2023 dollars) and Cost per Customer Minute Out (2023 dollars).
e. The Company utilizes ICE v2 Cost per Customer Event (2023 $) and Cost per Customer Minute Out (2023 $) as input values for Xcel Energy Electric Reliability Customer Minute Out Calculator as seen in Attachment A.
f. Xcel Energy Electric Reliability Customer Minute Out Calculator then calculates the combined CMO (2023 $) value.
g. Xcel Energy Electric Reliability Customer Minute Out Calculator applies a future value calculation that adjusts for inflation from 2023 to 2025.

2. Yes. We use Minnesota-specific inputs in ICE v2 and therefore the resulting interruption cost values used are specific to Minnesota customers.
3. ICE v2 does not accept customer-class specific outage minutes. It uses only overall SAIDI, SAIFI and CAIDI values for the state.
4. We apply customer class share based on our Minnesota customer base: 90 percent Residential and 10 percent Commercial and Industrial. These shares appear on the "ICE CMO Calc" sheet in Attachment A.
5. Based on ICE v2 outputs and class shares in Attachment A, the assumed value per avoided customer minute is $0.08 for Residential and $28.93 for

Commercial and Industrial. These shares appear on the "ICE CMO Calc" sheet in Attachment A.

6. Customer class share for statewide feeders statewide—calculated from the information listed in Attachment L—are: 90 percent Residential and 10 percent Commercial and Industrial. These shares appear on the "ICE CMO Calc" sheet in Attachment A. For the top 49 feeders used in the hypothetical scenarios, the mix is almost identical: 90.8 percent Residential and 9.2 percent Commercial and Industrial.
7. Because the feeder-specific shares from Section 6 are nearly identical to statewide shares, the resulting values in Section 5 do not materially change.

The Company also notes that applying different reliability values based on feeder class composition would elevate the value of service to non-residential customers relative to residential customers, which would conflict with past Commission directives. For example, in Order Point No. 6 of the Commission's December 5, 2023 Order in Docket No. E002/M-23-73, the Commission required the Company to "discuss how to lower the differences in SAIDI, SAIFI, and CAIDI between feeders associated with the different customer classes in their 2024 filing."

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Date:	January 8, 2026	

Attachment A is provided as a live Excel spreadsheet.

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Xcel Energy		Information Request No.	47
Docket No.:	E002/M-25-142		
Response To:	Minnesota Department of Commerce		
Requestor:	Ari Zwick, Bhavin Pradhan, Adway De, Krystal Binversie		
Date Received:	December 18, 2025		

Question:
Topic: Cost Benefit Analysis of Strategic Undergrounding - Assumptions
Reference(s): IDP Chapter 2, Pages 14-15

Xcel states:
Applying the ICE tool's valuation of $3.05 per minute to the 10.5 million CMO savings, translates to an annual customer benefit of over $31.9 million. This represents the economic value of increased reliability to the customers directly served by the undergrounded assets.
If the average duration reduction is conservatively set at 30 minutes, this would result in an estimated 0.57 million CMO savings. Applying the same $3.05 per minute value translates to an additional annual customer benefit of
$1.7 million.
The resulting benefit-cost ratio of 1.5 demonstrates that the reliability improvements in this scenario provide net economic value to customers, supporting the cost effectiveness of the Targeted Undergrounding Program and its alignment with long term grid modernization and customer service goals.
Please describe:

1. The methodology and assumptions Xcel used to calculate its cost benefit analysis referenced above.
2. Whether the cost benefit analysis includes the payment of replaced utility assets that are not fully depreciated.
3. If the answer to 2. is no, then provide a quantitative estimate of the average age of assets that Xcel would replace in its Strategic Undergrounding Program.
4. If the answer to 2. is no, then provide a quantitative estimate of the relative cost premium to install underground lines compared to overhead lines.

Response:

1. As described in Chapter 2, page 14 of the 2025 IDP, the Company characterized this analysis as an "Indication of Benefits," not a full Benefit Cost Analysis. This was one of two hypothetical analysis scenarios the Company provided to illustrate the potential value of Targeted Undergrounding.

In these scenarios, feeders were selected based on the amount of overhead infrastructure that could theoretically be converted to underground using the full $235 million program investment. Using the dollar per mile assumptions referenced in Docket No. E002/M-25-27—approximately $1.5 million per mile (or $31.7 million for 110,000 feet)—a total budget of $235 million could, hypothetically, underground all 154 overhead miles on the top 49 feeders identified in Docket No. E002/M-24-27 as having the highest number of customer interruptions per overhead line mile.

The Company then used 2023-2024 outage data related to overhead causes to estimate the number of customer interruptions that could have been avoided had these feeders already been undergrounded.

It is important to emphasize that this analysis was illustrative only and not indicative of the methodology that will ultimately be used for Site Selection Criteria. More information on the top 49 feeders identified in Docket No. E002/M-24-27 is provided in DOC Information Request No. 46, Attachment A (Trade Secret in Entirety). Further information on the calculation method is provided in DOC Information Request No. 48, Attachment A (Trade Secret in Entirety).

2. Yes, the revenue requirement estimate includes cost impacts associated with the retirement and removal of utility assets that have not been fully depreciated.

3. This information is not available.

4. This information is not available.

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Xcel Energy		Information Request No.	49
Docket No.:	E002/M-25-142		
Response To:	Minnesota Department of Commerce		
Requestor:	Ari Zwick, Bhavin Pradhan, Adway De, Krystal Binversie		
Date Received:	December 26, 2025		

Question:
Topic: FLISR Data
Reference(s): IDP Chapter 5, Pages 19-20

Please provide a list that contains the following data:

1. Fully operational date (connected to ADMS) for each FLISR installation.
2. Actual installation cost for each FLISR installation included in 1.
3. Circuit ID that corresponds to columns A and B of Attachment L – Circuit Table in Docket No. E002/M-25-27.
4. Number of times each the FLISR installation was activated by year.

Please provide the requested data in a Microsoft Excel executable format with all links and formulae intact. If any of these links target an outside file, please provide all such additional files.

Response:
The Company provides the following context: the term "FLISR Installation" does not have a universally defined meaning. As described on page 16 of the 2025 IDP, "the implementation of FLISR includes the deployment of automated field devices, upgrades and changes to substation relays, integration with ADMS, and finally, the use of FLISR [technology] by the DCC."

For purposes of answering Questions 1-3, the Company defines "FLISR installation" as an automated field device (reclosers and switches) installed as part of the FLISR project.

1. The term "fully operational date" is not explicitly defined and we interpret this term to mean the date that the "FLISR Installation" is complete. We provide this information as Please see Attachment A, which is Attachment J-1 in Docket No. E002/M-25-27.

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2. Please see Attachment B for actual installation costs for each FLISR Installation included in Question 1.

3. Please Attachment C for the number of times each the FLISR installation was activated by year. This attachment is also referred to as Attachment L in Docket No. E002/M-25-27.

   Much of the data in Attachment C has been marked as protected data. This information is "security information" as defined by Minn. Stat. § 13.37, subd. 1(a). As we have explained in past filings related to our treatment of customer data, we take our responsibility for all the data we maintain in order to provide our customers with reliable and safe service very seriously. We hear about data breaches impacting individuals and organizations almost daily. Responsible access to sensitive data must be balanced with accountability for third parties to demonstrate their actions with the data will be in the public interest before gaining access. Additionally, as we have pointed out in the past with respect to utility release of customer data, once released by the utility, the Commission will have no jurisdiction over third parties, and the utilities lose any ability to control its use, sale, or other dissemination.

   Our Company principles with respect to privacy and security are:
   - Maintain customer privacy, confidentiality, and security in terms of their usage and how they are connected to the grid, and
   - Avoid revealing details that would give a bad actor information to target an attack for maximum impact (e.g. peak load, equipment capacities, number of customers, how critical infrastructure is connected to the grid, etc.).

   Attachment C to this filing contains information that the Company believes could be manipulated to reveal the location and size of facilities serving our customers. The public disclosure or use of this information creates a risk because those who want to disrupt the electrical grid for political or other reasons may learn which facilities to target to create the greatest disruption. For this reason, pursuant to Minn. Stat. § 13.37, subd. 2, we have excised this data from the public version of our filing.

4. The term "activated" is not explicitly defined and we interpret this term to mean instances where automated field devices and the FLISR technology improved reliability. The Company provides this information in Attachment C.

   Portions of Attachment D are marked "Not-Public" as it contains information the Company considers to be security information as defined by Minn. Stat. § 13.37(1)(a). The public disclosure or use of this information creates an

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unacceptable risk because those who want to disrupt the electrical grid for political or other reasons may learn which facilities to target to create the greatest disruption. The Company takes efforts to protect this information from public disclosure. Thus, Xcel Energy excises this information as protected data pursuant to Minn. Rule 7829.0500.

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Date:	January 16, 2026

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Xcel Energy		Information Request No.	53
Docket No.:	E002/M-25-142		
Response To:	Minnesota Department of Commerce		
Requestor:	Ari Zwick, Bhavin Pradhan, Adway De, Krystal Binversie		
Date Received:	December 26, 2025		

Question:
Topic: Vegetation Management Budget
Reference(s): IDP Chapter 6, Page 21

In Table 6-8, Xcel forecasts an average annual vegetation management budget of $41.7 million.

Please provide an estimate of the change in annual customer minutes of outages after a 5-year budget that is:

1. Double Xcel's current vegetation management budget.
2. Half of Xcel's current vegetation management budget.

Response:
The Company object to this request as inherently speculative. Estimates of outage impacts from changes in vegetation management budgets are highly uncertain due to external factors such as wind, storms, and rainfall-driven growth rates, as well as non-linear relationships between spending and outage performance. These factors introduce substantial variability that renders precise forecasting unreliable.

For example, even if outages were estimated to double under certain conditions, those outages often cluster during storms, requiring sequential restoration due to field crew resource constraints. This can result in outage durations—and therefore customer minutes of interruption—far exceeding a simple proportional increase. Additionally, the per-mile cost of vegetation management increases at a compounding rate as vegetation cycles lengthen, further complicating predictive modeling.

Notwithstanding our objection, and given the inherent uncertainties, we provide the following illustrative ranges. We note that these ranges should not be considered precise forecasts.

1. Doubling the current vegetation management budget could improve annual customer minutes of interruption by approximately 10 to 40 million minutes

compared to current plans.

2. Reducing the budget by half could degrade annual customer minutes of interruption by approximately 100 to 300 million minutes compared to current plans.

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Date:	January 16, 2026

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Xcel Energy		Information Request No.	54
Docket No.:	E002/M-25-142		
Response To:	Minnesota Department of Commerce		
Requestor:	Ari Zwick, Bhavin Pradhan, Adway De, Krystal Binversie		
Date Received:	December 26, 2025		

Question:
Topic: DERMS Approach – Competitive Bidding
Reference(s): IDP Chapter 11

Please explain:

1. If Xcel has solicited for, and received multiple quotes for both its Aggregator DERMS and Grid DERMS solutions.
    a. Please describe how many bids were received for each DERMS solution, and if Xcel has selected a vendor, explain the reason for vendor selection.

2. If Xcel did not seek multiple bids, please explain how Xcel's approach minimizes costs to ratepayers.

Response:

1. Yes, we solicited and received multiple quotes for our Aggregator DERMS (ADERMS) and Grid DERMS solutions. We outline our evaluation process below in response to Question 1.a.

    a. The Company first explored the possibility of a single vendor for both Aggregator and Grid DERMS through the issuance of an RFI. After evaluating responses, it was determined that no single vendor had all the required capabilities. Therefore, the Company pursued separate vendors for Aggregator and Grid DERMS.

    Below we outline the competitive bidding process we used to engage our ADERMS vendor.

    - On Dec. 31, 2023, the Company completed developing 101 Use Cases and 1,080 Functional Requirements for an ADERMS platform.

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- In Q1 2024, an RFI was issued to 32 vendors that claimed to have an ADERMS platform. After evaluating responses, we narrowed the list to 7 vendors who were invited to submit a competitive response to our Request for Proposal (RFP).
- We issued our RFP on April 30, 2024, outlining a phased implementation approach over several years. Vendor responses were received by June 3, 2024.
- During the RFP review the functional requirements were focused on Phase 1, which involves deploying the Colorado Renewable Battery Connect (RBC) program.
- Our evaluation team completed vendor scoring by June 14, 2024. Three vendors were shortlisted for full-day demonstrations of our twelve prioritized use-cases. Demonstrations occurred July 29-31, 2024.
- The evaluation included technical capabilities, strategic roadmap, integrations, and non-functional requirements. Reference checks and pricing negotiations were also conducted.
- Based on our evaluation, a preferred vendor was identified and recommended to our executive leadership. A draft Statement of Work (SOW) was sent on October 17, 2024, and executed on December 17, 2024.

For Grid DERMS, the Company conducted an RFI in 2022, with analysis completed in October 2022 in collaboration with ESTA International. Please see Attachment A (Trade Secret In Entirety).

Attachment A is marked "Not-Public" in its entirety as it comprises information the Company considers to be trade secret data as defined by Minn. Stat. § 13.37(1)(b). The information contains confidential forecast data that derives an independent economic value from not being generally known or readily ascertainable by others who could obtain economic value or a financial advantage from its disclosure or use. The Company takes efforts to protect this information from public disclosure. Thus, Xcel Energy excises this information as protected data pursuant to Minn. Rule 7829.0500.

1. **Nature of the Material:** Bid Information
2. **Author(s):** Yashar Kenarangui
3. **Importance:** Contains not-public, proprietary information.
4. **Date the Information was Prepared:** October 2022

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2. Not applicable. The Company issued an RFP and sought multiple bids for both solutions.

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Date:	January 16, 2026	

Attachment A is marked "Not-Public" in its entirety as it comprises information the Company considers to be trade secret data as defined by Minn. Stat. § 13.37(1)(b). The information contains confidential forecast data that derives an independent economic value from not being generally known or readily ascertainable by others who could obtain economic value or a financial advantage from its disclosure or use. The Company takes efforts to protect this information from public disclosure. Thus, Xcel Energy excises this information as protected data pursuant to Minn. Rule 7829.0500.

1. **Nature of the Material:** Bid Information
2. **Author(s):** Yashar Kenarangui
3. **Importance:** Contains not-public, proprietary information.
4. **Date the Information was Prepared:** October 2022

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Xcel Energy		Information Request No.	55
Docket No.:	E002/M-25-142		
Response To:	Minnesota Department of Commerce		
Requestor:	Ari Zwick, Bhavin Pradhan, Adway De, Krystal Binversie		
Date Received:	December 26, 2025		

Question:
Topic: DERMS Approach – Vendor Selection Method
Reference(s): IDP Chapter 11, Page 8

Xcel states:
Consolidated Single Vendor Approach (Approach Not Selected)
With this approach, we would draft a comprehensive set of functional and nonfunctional requirements for both Aggregator DERMS and Grid DERMS for a RFP, toward selecting a single vendor to meet all the Company's DERMS needs. A benefit of this approach is that we would have enhanced vendor accountability, because a single vendor would be responsible for integration and maintenance. However, drawbacks include longer timelines for implementation and substantially higher costs. This approach would also restrict the Company from meeting near-term regulatory deadlines for certain capabilities in some of its states.

1. Please provide evidence of the "substantially higher costs" of a consolidated single vendor approach compared to costs associated with the Phased Parallel Path.
2. Please provide evidence of the "longer timelines for implementation" of a consolidated single vendor approach compared to costs associated with the Phased Parallel Path.

For clarification, the Department considers evidence to be cost quotes, formal responses to a request for proposals, or project implementation schedules.

Response:

1. The substantially higher costs for a single vendor approach are based on the Company's experience and findings from its RFI process. As noted in the Company's response to DOC IR No. 54, the Company conducted an RFI and determined that no single vendor could meet all requirements for both Aggregator DERMS and Grid DERMS. This is because Grid DERMS solutions are typically offered by technology vendors with an established Advanced Distribution Management System (ADMS) product, whereas

Aggregator DERMS solutions are generally provided by vendors that have an established Demand Response Management System (DRMS) product.

Selecting a single vendor would require that vendor to develop the missing capabilities outside its core competency, resulting in significant customization, increased development costs, and higher integration expenses. These factors drive the expectation of substantially higher costs compared to the phased parallel approach.

2. For the same reasons outlined above, requiring a single vendor to build new functionality would extend implementation timelines. Developing and integrating capabilities not currently offered would add complexity and delay, making it unlikely the Company could meet near-term regulatory deadlines for certain state-specific requirements.

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Date:	January 16, 2026	

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Xcel Energy		Information Request No.	57
Docket No.:	E002/M-25-142		
Response To:	Minnesota Department of Commerce		
Requestor:	Ari Zwick, Bhavin Pradhan, Adway De, Krystal Binversie		
Date Received:	December 26, 2025		

Question:
Topic: Benefits of DERMS
Reference(s): IDP Chapter 11

Please present any analysis Xcel has conducted to quantify potential cost savings of a Grid DERMS and Aggregator DERMS deployment. Please explain how these cost savings improve upon standard business practices.

Response:
The Company has not formally quantified cost savings for Grid DERMS (GDERMS) and Aggregator DERMS (ADERMS). However, we anticipate several categories of savings based on expected functionality and process improvements.

By consolidating multiple legacy programs and software platforms, ADERMS is expected to reduce:

- Software licensing costs by eliminating redundant systems.
- Labor costs associated with operating and supporting multiple platforms.
- Transactional costs related to maintaining and negotiating separate vendor contracts.

Additional benefits associated with ADERMS include cost avoidance for upgrading aging software, retiring obsolete assets, and reducing operational expenditures. ADERMS also supports incremental revenue opportunities through growing adoption of Distributed Energy Resources (DERs), such as electric vehicles and battery storage.

Cost savings for GDERMS typically occur on a per-use-case basis and may benefit either customers or the Company. For example, in the Flexible Interconnection use case, solar garden owners can choose limited curtailment to avoid costly infrastructure upgrades. GDERMS also provides foundational capabilities for monitoring, managing, and controlling DERs, improving situational awareness, interoperability, and coordination across diverse technologies—streamlining processes and reducing inefficiencies compared to standard practices.

Additionally, coordinating ADERMS and GDERMS is expected to unlock greater benefits than either system alone. Integration enhances visibility and control across all DERs, improves grid reliability and efficiency, and maximizes the return on DERMS investments. Achieving this further value through GDERMS and ADERMS is a future effort and an iterative, multi-year process, following a deliberate walk-jog-run progression as capabilities mature and interoperability standards evolve.

Preparer:	Shawn White	Yashar Kenarangui
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Department:	Customer and Innovation	Distribution Electric Engineering
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Date:	January 16, 2026	

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Xcel Energy		Information Request No.	58
Docket No.:	E002/M-25-142		
Response To:	Minnesota Department of Commerce		
Requestor:	Ari Zwick, Bhavin Pradhan, Adway De, Krystal Binversie		
Date Received:	December 26, 2025		

Question:
Topic: Grid DERMS Deployment Cost
Reference(s): IDP Chapter 11, Page 21

Xcel estimates that its "limited Grid DERMS deployment" will cost $2.9 million. Please provide an estimate of how much a full-scale deployment of a Grid DERMS would cost. In order to accommodate for different scopes and features, please provide a range of potential costs.

Response:
The Company cannot provide an estimate for full-scale Grid DERMS deployment, as noted in IDP Chapter 11, page 21.

Importantly, Grid DERMS costs extend beyond simply the purchase of software. Total costs include deployment and licensing expenses, ongoing operating costs, field and communication equipment required to enable DER connectivity, and organization and people management costs, such as training, change management, business process updates, and readiness activities. Because these categories vary significantly based on many of the factors listed above, providing a cost range is not possible at this time.

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Department:	System Planning and Strategy
Telephone:	303-571-3502
Date:	January 16, 2026

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Xcel Energy		Information Request No.	59
Docket No.:	E002/M-25-142		
Response To:	Minnesota Department of Commerce		
Requestor:	Ari Zwick, Bhavin Pradhan, Adway De, Krystal Binversie		
Date Received:	December 26, 2025		

Question:
Topic: Aggregator DERMS Deployment Cost
Reference(s): IDP Chapter 11, Page 21

Please provide an estimate of how much a full-scale deployment of an Aggregator DERMS would cost. In order to accommodate for different scopes and features, please provide a range of potential costs.

Response:
The Company currently forecasts Aggregator DERMS deployment costs ranging between $4 million and $6 million, spread over several years.

At this time, Aggregator DERMS scope is limited to supporting existing demand response products/programs. The Company has not yet estimated costs for integration with distribution system management tools, as those requirements will depend on future design decisions and regulatory guidance.

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Date:	January 16, 2026

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Xcel Energy		Information Request No.	61
Docket No.:	E002/M-25-142		
Response To:	Minnesota Department of Commerce		
Requestor:	Ari Zwick, Bhavin Pradhan, Adway De, Krystal Binversie		
Date Received:	December 26, 2025		

Question:
Topic: Capacity Risk Scoring – Risk Score
Reference(s): IDP Attachment E

Attachment E lists 193 projects, totaling $496 million. Of these projects, 105 projects have a risk score below 1.0, which totals $290 million. In Attachment D, Xcel outlines several reasons why a project may be prioritized that accounts for other factors outside of the risk score, which includes mandates, new business, asset health, blankets, and programs.

Please explain why over half of the selected projects have risk scores below 1.0. The answer should delineate between spending because of the alternative prioritization factors described above, and spending, if any, on projects whose benefits are fully captured within Xcel's Capacity Risk Score model.

Response:
Over half of the selected projects have risk scores below 1.0 because the Capacity Risk Score is only one factor in project prioritization. As outlined in Attachment D of the IDP, other factors include mandates, new business, asset health, blanket projects, and program needs. These factors often drive project selection even when the calculated risk score is relatively low.

It is not possible to precisely delineate spending between these factors because many projects deliver overlapping benefits. For example, replacing a transformer may provide capacity, asset health, and operational benefits, but it is accounted for in a single project.

The Capacity Risk Score model is a prioritization tool, not the sole determinant. Engineering judgment is also applied to ensure that our distribution grid evolves to accommodate new load, integrate DERs, and maintain safety and reliability. This includes addressing public and employee safety, improving resilience and enabling

timely customer connections—all of which may justify selecting projects with lower risk scores.

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Xcel Energy		Information Request No.	63
Docket No.:	E002/M-25-142		
Response To:	Minnesota Department of Commerce		
Requestor:	Ari Zwick, Bhavin Pradhan, Adway De, Krystal Binversie		
Date Received:	December 26, 2025		

Question:
Topic: Capacity Risk Scoring – Probability of an N-1 Event
Reference(s): IDP Attachment D

Please explain:

1. How Xcel's Capacity Risk Scoring Methodology accounts for the probability of N-1 events.

2. How the probability of an N-1 event is used to determine the avoided customer minutes of outages (CMO) benefit?

Response:

1. Contingency (N-1) risks are calculated independently from Overloads (N-0). The methodology incorporates the probability of an N-1 event through a failure rate applied to the calculation of potential outage impacts.

2. The avoided CMO benefit for N-1 events is calculated using the following formula: (0.5)(Peak Load MVA – Available Relief MVA)(Customers per MVA)(Peak Day hours out/24)(Hours to restore)(60 minutes)(Failure Rate). This formula applies the failure rate to capture the likelihood of an N-1 event and its impact on outage duration and customer exposure.

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Date:	January 16, 2026

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Xcel Energy		Information Request No.	64
Docket No.:	E002/M-25-142		
Response To:	Minnesota Department of Commerce		
Requestor:	Ari Zwick, Bhavin Pradhan, Adway De, Krystal Binversie		
Date Received:	December 26, 2025		

Question:
Topic: Capacity Risk Scoring – Probability of N-1 and Peak Load Event
Reference(s): IDP Attachment D

Please explain how Xcel's Capacity Risk Scoring Methodology accounts for the probability that an N-1 event will occur at the same time as a peak load event on the transformer or feeder being studied for mitigation.

Response:
While the Capacity Risk Scoring methodology does not combine the probability of an N-1 contingency event occurring simultaneously with a peak load event, the annual hours at risk are included within the N-1 calculation based on the estimated load duration curve for the asset.

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Xcel Energy		Information Request No.	66
Docket No.:	E002/M-25-142		
Response To:	Minnesota Department of Commerce		
Requestor:	Ari Zwick, Bhavin Pradhan, Adway De, Krystal Binversie		
Date Received:	December 26, 2025		

Question:
Topic: Capacity Planning Load Limits
Reference(s): IDP Chapter 1, Page 83

Please describe any analysis Xcel has performed to determine the cost-effectiveness of its N-0 and N-1 load limit risk thresholds, as outlined in Table 1-12. Please provide a copy of the analyses performed that demonstrate the value of Xcel's planning standards.
Please provide the requested data in a Microsoft Excel executable format with all links and formulae intact. If any of these links target an outside file, please provide all such additional files.

Response:
The Company has not completed a cost-effectiveness analysis of the N-0 and N-1 load limit risk thresholds in Table 1-12. Accordingly, there are no analyses to provide in Excel format. The Company's planned loading limits are established based on engineering analysis and system design, not cost-effectiveness.

For background on the planning standards and the engineering rationale behind these thresholds, please see IDP Chapter 1, Section D ("Planning Criteria and Design Guidelines"). Key excerpts (unaltered) are provided below for convenience:

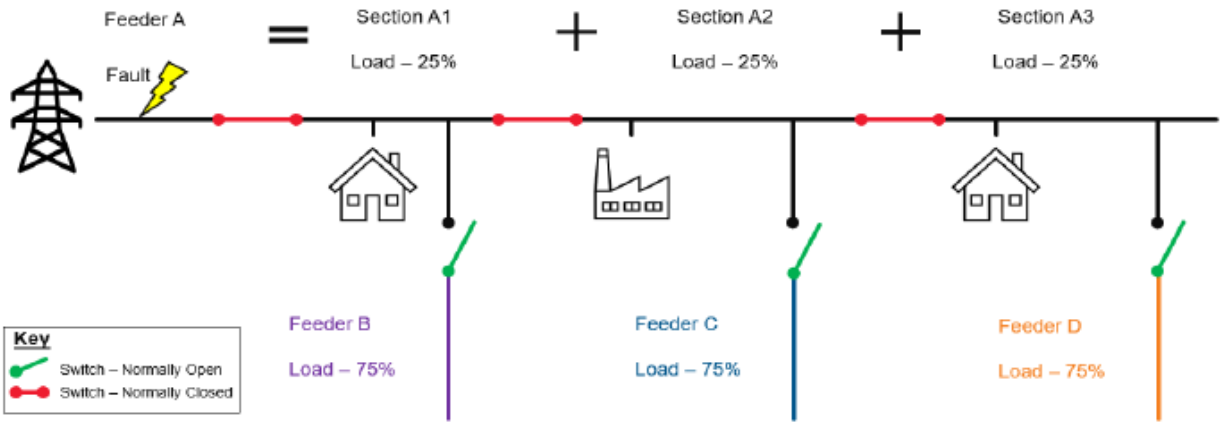
2025 IDP in chapter 1 Page 19:

> The lower planned loading limits (50%) for higher voltage classes reflect the unique two-feeder configuration of most 25/35kV substations. *Note: This means one entire feeder transfers to the other feeder during N-1.* These feeders are often used to cover longer distances, making them well-suited for outstate regions, but this extended reach also limits the number of available field ties for contingency support.

2025 IDP in chapter 1 page 21-22:

> Figure 1-8 illustrates this concept using a 75 percent planned load limit for a mainline feeder, with three sections each loaded to 25 percent of total capacity. Green and red symbols represent switches that can isolate or connect feeder sections in the event of a fault. In such cases, the substation breaker isolates the faulted feeder, and section switches are operated to maintain service to unaffected customers while repairs are made.

Figure 1-8
Typical Mainline Distribution Feeder with Three Sections Capable of System Intact N-0 and First Contingency N-1 Operations
Mainline Feeder No. 1



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

As additional context, any load at risk under an N-1 condition—meaning any amount of MVA exposed to a contingency—is considered a reliability concern for the system. Similarly, when transformer loading exceeds its rating for a continuous time, it presents a reliability issue and may begin to contribute to transformer loss of life, as described in Chapter 1, page 24. Because the distribution system is largely radial, maintaining N-1 capabilities is essential to ensuring year-round reliability. These capabilities allow the system to take advantage of FLISR operations, which provide rapid sectionalizing and restoration during fault events. When N-1 planning is integrated with automation strategies such as FLISR, the result is a more resilient grid, reduced outage durations, and overall improvement in customer reliability metrics.

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Date:	January 16, 2026

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Xcel Energy		Information Request No.	67
Docket No.:	E002/M-25-142		
Response To:	Minnesota Department of Commerce		
Requestor:	Ari Zwick, Bhavin Pradhan, Adway De, Krystal Binversie		
Date Received:	December 26, 2025		

Question:
Topic: Capacity Planning Load Limits – Relaxation 1
Reference(s): IDP Chapter 1, Page 83

In Table 1-12, Xcel outlines its N-0 and N-1 load limit risk thresholds. In Attachment D, Xcel explains its Risk Scoring Methodology.
For the following scenarios, assume that A) Xcel has budget capacity for each scenario, and B) there are no other extraneous factors that would require a re-prioritization of the project. Would Xcel proceed with a mitigation in the following scenarios?

1. A project has an N-0 risk with a risk score of 1.25.
2. A project has an N-0 risk with a risk score of 0.75.
3. A project has an N-1 risk with a risk score of 1.25.
4. A project has an N-1 risk with a risk score of 0.75.

Response:
We object to this request as speculative. Providing definitive "yes/no" determinations about whether the Company would proceed with a mitigation in each hypothetical scenario would necessarily require speculation about future engineering decisions, system conditions, operational needs, and prioritization factors.

Not withstanding our objection, we provide the following information in response to this request.

As explained in Attachment D, the Company's risk scoring methodology incorporates a combination of qualitative and quantitative considerations, and the final decision to pursue a mitigation project depends on the full context of system conditions, engineering judgment, operational needs, and risk management prioritization.

While Table 1-12 provides N-0 and N-1 load limit thresholds, these thresholds do not operate as automatic triggers for funding a mitigation. Similarly, risk scores do not function as strict pass–fail criteria. It is important to note that a risk itself does not

receive a score; instead a mitigation project, which may address multiple risks, receives an aggregated risk score. Over time, all risks get included in the budget and eventually become associated with a mitigation project.

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Xcel Energy		Information Request No.	68
Docket No.:	E002/M-25-142		
Response To:	Minnesota Department of Commerce		
Requestor:	Ari Zwick, Bhavin Pradhan, Adway De, Krystal Binversie		
Date Received:	December 26, 2025		

Question:
Topic: Capacity Planning Load Limits – Relaxation 2
Reference(s): IDP Chapter 1, Page 83

In Table 1-12, Xcel outlines its N-0 and N-1 load limit risk thresholds. In Attachment D, Xcel explains its Risk Scoring Methodology.
Without consideration of any extraneous factors, does Xcel's Capacity Risk Score methodology, outlined in Attachment D, effectively determine if an N-0 or N-1 mitigation will be pursued by Xcel? To re-frame the question, does the Capacity Risk Score allow Xcel to determine if it is acceptable to exceed Xcel's N-0 and N-1 planning limits if the mitigations are not found to be cost-effective?

Response:
No. Our Capacity Risk Score methodology, as described in Attachment D, is one tool used to inform whether an N-0 or N-1 mitigation project should be pursued. It helps inform and prioritize projects, but it does not serve as a pass–fail test or allow the Company to exceed its N-0 or N-1 planning limits if a mitigation is not considered cost effective. Decisions rely on engineering judgment and broader system considerations.

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Xcel Energy		Information Request No.	70
Docket No.:	E002/M-25-142		
Response To:	Minnesota Department of Commerce		
Requestor:	Ari Zwick, Bhavin Pradhan, Adway De, Krystal Binversie		
Date Received:	December 26, 2025		

Question:
Topic: Planning Load Limit – Sizing for Future Needs
Reference(s): IDP Chapter 1, Page 19

Xcel states:

> The planned loading limits serve as a guiding principle that enables consistent evaluation across the system and provides a scalable abstraction for complex analyses—such as in long-term studies or in dense metro areas with network feeders. In practice, we regularly load feeders beyond the planned loading limit with analysis from engineering determining where risks may be present and mitigations are necessary. Additionally, when designing a mitigation, we seek to achieve the planned loading limits to ensure the solution meets the design needs for the life of the solution. These thresholds are flagged in our planning tools and processes to ensure that higher loading levels are carefully assessed and mitigated when doing so is determined to be prudent.

Based on the above statement, if the design need indicates a design capacity that is 50 percent higher in year 30 than in year 5, will Xcel design the mitigation to the year 5 capacity need, the year 30 capacity need, or something else?

Response:
There is no single rule for sizing mitigations to a specific forecast year. The appropriate design horizon depends on the type of project and system conditions. For example feeder-level projects may only use a 5-10 year horizon, while larger infrastructure additions—such as new substations or transformer additions—are generally designed to meet needs across a 10-30 year horizon.

In all cases, the goal is to design solutions that meet future needs, avoid premature rebuilds, and serve as building blocks for long-term plans. Customer load patterns, new development, and DER adoption can change from year to year, which is why planning is revisited annually. As a result, while a mitigation may align with today's forecast, that forecast may evolve, and design decisions must balance long term needs with prudent investment.

The Company does its best to avoid rebuilding the system by taking into account future needs. The Company also points out the need to remember that the distribution system is very dynamic. New customers come in, customers move their businesses, residential customers change their habits – therefore, while our plan may meet the forecast today, the forecast could change the following year – which is why we do this process annually.

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Date:	January 16, 2026

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		Revision
Xcel Energy	Information Request No.	74
Docket No.:	E002/M-25-142	
Response To:	Minnesota Department of Commerce	
Requestor:	Ari Zwick, Bhavin Pradhan, Adway De, Krystal Binversie	
Date Received:	December 26, 2025	

Question:
Topic: LoadSEER Forecast Accuracy of Planned Projects
Reference(s): IDP Attachment E

For each project in Attachment E with "Planned Spending in 5 Year Budget" of $5 million or greater, please present the Actual Peak Load and LoadSEER Predicted Peak Load for the years 2021-2024.
Please provide the requested data in a Microsoft Excel executable format with all links and formulae intact. If any of these links target an outside file, please provide all such additional files.

Response:
Historic peak loads are not tracked for all assets. As part of Order Point 5 of the Commission's 2024 IDP Order, we completed a significant one-time data cleaning effort to compare actuals to forecasts, but the effort focused on feeder data and did not include transformer banks. Therefore, we do not have complete asset-level historical data to fully respond to this request.

Attachment A provides the Actual Peak Load and LoadSEER Predicted Peak Load for projects with "Planned Spending in 5 Year Budget" of $5 million or greater. Because the request seeks predicted values comparable to historical values, the forecast must come from a scenario vintage older than the historical years being compared. The 2025 IDP scenarios contain forecasts only for 2026 and beyond and therefore cannot be used for 2021–2024 comparisons. As the request did not specify a forecast scenario, we provide the 2023 IDP Low scenario for this purpose. Please note that, because transformers were not included in the 2025 data cleaning effort described above, historical peak information is incomplete for some assets.

Attachment A is provided as a Microsoft Excel workbook with all links and formulae intact.

Revised
The Company's supplemental response contains updated markings to reflect non-public material. It was brought to the Company's attention that the initial response contained unredacted material that should have been characterized as nonpublic/trade secret pursuant

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to Minnesota Statutes Ch. 13. Consistent with the justification below, this supplemental response now properly marks and redacts the nonpublic/trade secret material in the public version and contains appropriate justifications and markings. The Company respectfully requests that recipients of this supplemental response destroy all copies of the original response to DOC IR No. 74.

Portions of Attachment A are pulled from Attachment E, which is considered trade secret. Attachment E contains two shaded and marked columns that contain (1) forecasted peak demand and (2) peak capacity by feeder and/or substation that Xcel Energy maintains as Security Information, pursuant to Minn. Stat. § 13.37, subd. 1(a).

The public disclosure or use of this information creates an unacceptable risk that those who want to disrupt our system for political or other reasons may learn which facilities to target to create a disruption of our service. Additionally, these fields for certain feeders contain information that if made public would be counter to our requirement to protect the anonymity of our customers' energy usage information unless we have the customers' consent to disclose it (Commission Order dated January 19, 2017 in Docket No. E,G999/CI-12-1344).

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Date:	January 16, 2026
Revised:	January 28, 2026

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Xcel Energy		Information Request No.	81
Docket No.:	E002/M-25-142		
Response To:	Minnesota Department of Commerce		
Requestor:	Ari Zwick, Bhavin Pradhan, Adway De, Krystal Binversie		
Date Received:	December 26, 2025		

Question:
Topic: NWA Period of Analysis
Reference(s): IDP Chapter 8, Page 3

Xcel states:

> [W]e examined the peak load curve for each feeder or transformer risk, forecasted through the end of the deferral period (five years after the planned in-service date of the traditional project.

Please explain why Xcel chose a deferral period of five years, instead of each of the following deferral periods listed below. Please respond individually to each deferral period listed.

1. 0 years
2. 1 year
3. 2 years
4. 4 years
5. 6 years
6. 10 years
7. The modeled time in which the NWA solution is no longer expected to mitigate the capacity risk.

Response:
The five-year deferral period is based on the stacked benefit analysis developed in 2020 and 2021 in collaboration with stakeholders. The Company originally used a 10-year deferral window because it resulted in larger accrued deferral benefits. However, doing so came at the cost of needing a larger NWA solution, since the NWA solution is sized to mitigate the risk for the entire deferral period. As the load forecast increases over time, a longer deferral period requires a larger NWA size to accommodate additional forecasted load growth. This frequently resulted in the NWA solutions becoming infeasibly large.

To balance the competing objectives—capturing meaningful deferral benefits while keeping NWA sizes reasonable—the Company reduced the deferral window from 10

years to five years. This five-year period was selected because it strikes a balance between (1) the deferral benefits accrued over that timeframe and (2) the size and cost implications of building an NWA capable of mitigating the capacity risk for the entire deferral period.

The same basic rationale explains why the Company does not use the other deferral periods. A 0 year period provides no deferral benefit because the traditional project would not be delayed at all. One and two year periods offer only limited deferral value, and while they require smaller NWA solutions, the benefit is too small to justify altering the standard five year window. A four year period is closer to five but still yields fewer total benefits without meaningfully improving feasibility.

Longer windows reintroduce the issues seen with the original ten year approach. A six year period requires the NWA to cover more forecasted load growth, increasing the size and cost of the solution. A ten year window was used initially but consistently produced NWA solutions that were too large to be practical, which is why the Company shortened the window to five years. Finally, because the initial NWA screening process sizes the solution to cover the entire selected deferral window, the modeled year in which the NWA solution is no longer expected to mitigate the capacity risk will always match the assumed the deferral period.

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Date:	January 16, 2026

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Xcel Energy		Information Request No.	84
Docket No.:	E002/M-25-142		
Response To:	Minnesota Department of Commerce		
Requestor:	Ari Zwick, Bhavin Pradhan, Adway De, Krystal Binversie		
Date Received:	December 26, 2025		

Question:
Topic: NWA Project Analysis
Reference(s): 2025 Integrated Distribution Plan, Chapter 8, p. 2, 4

In its IDP, Xcel states on page two of Chapter 8:
Our 2025 NWA analysis reviewed 12 projects selected using established NWA criteria. The process largely mirrored our 2024 approach, with one key enhancement: the inclusion of the Planned Net Loading methodology for assessing N-0 risks. Of the 12 projects analyzed, six were found to be technically feasible, though not cost-beneficial in all cases.
The Company includes the results summary of nine out of 12 projects in Table 8-1 on page four of Chapter 8. Xcel also provides a detailed summary of the results on five of the six feasible projects.
Please provide summary of results for the three projects not included, as well as a detailed results summary for the one feasible project the Company did not include in its 2025 Integrated Distribution Plan. If Xcel is unable to provide this information, please explain why these projects were not included.

Response:
The three projects not included in Table 8-1 are listed below. Of these, two were found to be infeasible, and one was technically feasible but removed from further analysis because the underlying risk did not exceed planning limits.

Because these projects were disqualified during the screening process, the Company did not prepare detailed NWA results summaries for them, including the one technically feasible project. The basis for each exclusion is explained below.

1. Install West Coon Rapids (WCR) Transformer

   Status: Disqualified – Not Feasible
   Reason: Under the N-1 condition, this transformer lacks a bus tie, meaning that an NWA solution would need to cover the entire transformer load for all 8,760

annual hours at risk. This requirement made an NWA solution infeasible under the Company's screening criteria as it is effectively a single bank substation.

2. Install Two 50 MVA TRs at Brooklyn Park
   Status: Disqualified - Not Feasible / No Risk
   Reason: After further refinement of the risk analysis under the N-1 condition for one transformer, it was determined that the available transferrable load eliminated any load at risk. Because no remaining capacity violation existed, the project did not meet the criteria for NWA evaluation.

3. Install Lone Oak (LOK) TR3
   Status: Disqualified – Technically Feasible but Below Planning Limits
   Reason: After further refinement of the forecast under the N-0 condition, the transformer was forecasted to operate at 87% of its capacity rating, which does not trigger capacity driven investment under the Company's planning standards. As a result, this project did not qualify for full NWA analysis, and therefore no detailed NWA results summary was prepared.

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Date: January 16, 2026

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Xcel Energy		Information Request No.	90
Docket No.:	E002/M-25-142		
Response To:	Minnesota Department of Commerce		
Requestor:	Ari Zwick, Diane Dietz, Rachel Wiedewitsch, Bhavin Pradhan, Krystal Binversie		
Date Received:	December 31, 2025		

Question:
Topic: Wildfire Mitigation Strategy
Reference(s): 2025 IDP Chapter 2 at 27 – situational awareness tools

1. Please discuss how the company's Advanced Fire Modelling Software is utilized within the Company.
    a. Is this "Advanced Fire Modelling Software" the FireSight tool that is discussed in the Company's rate case (Sherwood Supplemental Direct)?[1]
    b. Are there third-party data or other resources publicly available for use that could serve the same purpose?
    c. What are the costs associated with the software? Please include initial procurement fees as well any ongoing operational fees or subscription/licensing fees.

2. Has the Company completed any studies (within its Minnesota territory) as to the effectiveness of AI Cameras to detect smoke or fire signatures? a. Please provide proposed AI Camera reporting metrics that the Company could include in its next IDP.

[1] *In the Matter of the Application of the Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota*, Sherwood Supplemental Direct Testimony, Xcel Energy, March 17, 2025, Docket No. E002/GR-24-320, (eDockets) 20253-216469-06, at 8.

Response to Question 1:
The Company's use and costs associated with its Advanced Fire Modelling Software are properly addressed in the pending electric rate case. This Information Request falls outside the scope of the Integrated Distribution Plan (IDP). The 2025 IDP does not reference the Advanced Fire Modelling Software, nor does it include any proposals, budgets, or strategies related to that tool. For these reasons, further discussion of its use, alternatives, or costs is not appropriate within this proceeding.

Notwithstanding our concerns, we provide the following information in response to Question 1.

a. The Advanced Fire Modelling Software is the FireSight tool discussed in the Company's rate case testimony.
b. There are no fully equivalent publicly available resources because our Advanced Fire Modeling Software depends on proprietary data integrations, specialized risk modeling methods, and operational decision support tools designed specifically for our electric grid.
c. The costs associated with the Technosylva solution is discussed in the ongoing MN Electric Rate Case.

Response to Question 2:
The Company has not completed any studies within its Minnesota service territory evaluating the effectiveness of AI-enabled cameras for smoke or fire signature detection. Because the Company's wildfire mitigation budget—including potential deployment of AI camera technology—is still under consideration in the pending electric rate case, it would be premature to identify reporting metrics for inclusion in the 2027 IDP.

Until the Commission determines the Company's wildfire mitigation budget and approves (or declines to approve) tools such as AI cameras, the Company cannot meaningfully determine which technologies will be implemented or what metrics would be appropriate for future IDP reporting.

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Xcel Energy		Information Request No.	91
Docket No.:	E002/M-25-142		
Response To:	Minnesota Department of Commerce		
Requestor:	Ari Zwick, Diane Dietz, Rachel Wiedewitsch, Bhavin Pradhan, Krystal Binversie		
Date Received:	December 31, 2025		

Question:
Topic: Wildfire Mitigation Strategy
Reference(s): 2025 IDP Chapter 2 at 27 -- System Resiliency Enhancements

1. Please provide a description as to how each the proposed System Resiliency Enhancements vary from traditional system resiliency efforts conducted by the Company.
    a. Are system hardening (involves replacing vulnerable components with fire-resistant materials and designs) and non-expulsion equipment replacement (Transitioning to Cal Fire-rated fuses and arresters that minimize the risk of sparks during fault conditions) being employed proactively across the system, or as components become due for replacement?
        i. What are the criteria utilized to determine where to employ these system enhancements if employed proactively?

Response:
1. The Company's proposed System Resiliency Enhancements differ from traditional resiliency programs by focusing specifically on both proactively inspecting and replacing distribution poles as well as small primary and secondary conductors in Tier 2 and 3 areas based on Wildfire Risk severity (prioritizing Tier 3, then Tier 2). Unlike traditional system resiliency efforts, these System Resiliency Enhancements would be focused on areas of heightened wildfire risk and would include a larger volume of work or a higher cadence of inspection due to heightened wildfire risk.

Overhead Pole Assessment (OPA): Instead of traditional ground-level pole inspection programs which are performed on 12 year cycles, the Company would inspect all Tier 3 poles every 3 years (1/3 per year) and all Tier 2 poles every 6 years (1/6 per year) using comprehensive drone-based aerial assessment. This allows for a higher inspection cadence and more detailed evaluation of poles and overhead equipment along wildfire-risk feeders.

Pole Loading and Clearance (PLC): This effort employs LiDAR-based drone inspections to evaluate 5% of all Tier 2 and 3 poles annually—a scale not currently used by the Company. This approach provides earlier identification of structural loading issues and clearance violations, enabling proactive remediation before equipment failure in areas of heightened wildfire risk.

Small Wire, Covered Conductor, and Open-Wire Secondary Replacements: These System Resiliency Enhancements target replacement of older, less durable primary and secondary conductors in Wildfire Risk Tier 2 and 3 areas. Unlike traditional system resiliency work, which is typically triggered by age, condition, or system performance, these replacements are planned proactively and at a significantly larger scale, with annual targets for conductor replacements.

a. System hardening efforts—including the deployment of fire-resistant materials, upgraded designs, and the replacement of traditional expulsion-type equipment with non-expulsion, Cal Fire-rated fuses and arresters—would be undertaken proactively rather than waiting for components to reach their end of life. These efforts would begin on feeders that include segments located within the Company's highest risk wildfire areas, particularly in Wildfire Risk Tier 3 area, and would continue until all relevant segments in Tier 2 and 3 areas are addressed.

i. Deployment of system enhancements would be prioritized based on the Company's approved Wildfire Risk Map, with Tier 3 areas addressed first, followed by Tier 2 areas. Within these tiers, segments would be scheduled according to modeled wildfire risk levels so that enhancements occur first where risk reduction benefits are greatest.

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Email:	bailey.bergeron@xcelenergy.com
Date:	January 12, 2026

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Xcel Energy		Information Request No.	92
Docket No.:	E002/M-25-142		
Response To:	Minnesota Department of Commerce		
Requestor:	Ari Zwick, Diane Dietz, Rachel Wiedewitsch, Bhavin Pradhan, Krystal Binversie		
Date Received:	December 31, 2025		

Question:
Topic: Wildfire Mitigation Strategy
Reference(s): 2025 IDP Chapter 2 at 28.

1. Please discuss how the company's vegetation management tools identified in its wildfire mitigation strategy in the IDP vary from and/or improve upon the vegetation management plans included in the Company's SRSQ.

Response:
The SRSQ filed April 1st, 2025, provides only a brief description of our Vegetation Management program, noting generally that "[t]he overall goal of our Vegetation Management Program is to maintain an approximate five-year cycle of continual vegetation maintenance." In contrast, the IDP filed October 31, 2025 provides a more comprehensive description of the program including how vegetation management time is determined.

In the IDP, the Company describes a hybrid approach that uses both time-based cycles and risk-based modeling, supported by tools such as satellite imagery and AI analytics. This approach builds on the SRSQ by explaining how advanced data is used to better address potential vegetation related risks—demonstrating our ongoing commitment to delivering excellent service and improving reliability for our customers.

Because vegetation characteristics vary widely across the Company's service territory—including differences in tree density, tree species growth rates and failure risks, and accessibility—relying solely on a fixed cycle is not always effective. The hybrid approach described in the IDP allows the Company to prioritize work based on actual risk, improving efficiency, reducing potential service disruptions, and enhancing service reliability.

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Date:	January 12, 2026	

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Xcel Energy		Information Request No.	93
Docket No.:	E002/M-25-142		
Response To:	Minnesota Department of Commerce		
Requestor:	Ari Zwick, Diane Dietz, Rachel Wiedewitsch, Bhavin Pradhan, Krystal Binversie		
Date Received:	December 31, 2025		

Question:
Topic: Wildfire Mitigation Strategy
Reference(s): 2025 IDP Chapter 2 at 28 – Operational Mitigations

1. Please provide additional context for the scenarios under which the company would implement Enhanced Powerline Safety Settings (EPSS) and Public Safety Power Shutoffs (PSPS).
2. In the event of, and in the lead up to, a Public Safety Power Shutoff (PSPS), what methods would the company employ to communicate with impacted customers and other stakeholders, including state agencies, local governments, and local emergency management? Please make reference to any written protocols or procedures that the company has for this type of communications.
3. What strategies does the company have in place to mitigate the potential harms to customers of a Public Safety Power Shutoff (PSPS)? What potential harms to customers has the company identified that could arise from using PSPS? Include a discussion of how the company is working to mitigate impacts on customers who rely on electric service to operate medically necessary devices, and large institutions, such as hospitals and nursing homes, that have numerous vulnerable residents.

Response:

1. The Company may implement EPSS or PSPS depending on wildfire risk due to wildfire weather conditions described in the Company's Wildfire Safety Operations (WSO) Playbook.

   Under elevated wildfire risk, based on real-time weather conditions, the Company implements WSO on a zone-by-zone basis within the Wildfire Risk map. EPSS is then applied to EPSS-capable feeders in the affected zone, allowing for more sensitive protection settings and disabling reclosing to reduce ignition risk.

If conditions escalate to a point where EPSS is not sufficient to manage wildfire risk, the Company may implement a PSPS. This decision is based on assessments from the Wildfire Meteorology and Wildfire Risk teams regarding expected fire behavior, fuel conditions, and forecasted weather.

2. If the Company determines that a PSPS is necessary, communication and notification activities follow the processes outlined in the Public Safety Power Shutoff Playbook and associated PSPS Communications Playbook. As the Wildfire Meteorology and Wildfire Risk teams identify affected zones and feeders, the Company initiates notifications to affected customers, state and local governments, and local emergency management organizations.

3. When evaluating and executing a PSPS, the Company performs additional scoping analysis, per the PSPS Playbook, to identify affected critical customers. To minimize impacts, the Company evaluates operational solutions to maintain power to as many customers as reasonably possible. This includes assessing: EPSS coverage capability, vegetation hazards, primary underground assets and operational switching capabilities, and the latest OPA and PLC inspection data for asset health indications. These considerations guide the Company's efforts to reduce the scope and duration of a PSPS while managing wildfire ignition risk.

   Although the primary goal of a PSPS is to reduce wildfire risk to the public and environment as possible, each wildfire-weather scenario is different. The company relies on the PSPS Playbook to ensure consistent evaluation, timely execution, and notification procedures for affected customers, state and local government, and emergency services.

   In addition, the Company's broader system hardening efforts—including EPSS deployment, overhead pole/asset and pole load/condition remediation, replacement of expulsion equipment, and conductor and pole replacement—provides additional flexibility to sectionalize more effectively, limit the scope of PSPS events, and reduce wildfire risk in high-risk areas.

   Regarding customers who rely on electric service to operate medically necessary devices, and large institutions such as hospitals and nursing homes, the Company has a medically necessary equipment certification in place, with a form posted on the Company's website.[1] Information gathered from this form allows the Company to know where those customers are, but this information is not currently integrated with our wildfire risk mitigation plans. Most

[1] See https://www.xcelenergy.com/staticfiles/xe-responsive/Safety/Medically%20Necessary%20Equipment%20&%20Emergency%20Certification%20Form.pdf.

hospitals and other large institutions for medically vulnerable populations have back-up generation. The Company also has a current program, the Resilient Minneapolis Project, which will install resilience microgrids in three Minneapolis neighborhoods allowing those facilities to have power and serve as safe gathering spaces during a grid outage.

Preparer: Bailey Bergeron
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Xcel Energy		Information Request No.	94
Docket No.:	E002/M-25-142		
Response To:	Minnesota Department of Commerce		
Requestor:	Ari Zwick, Diane Dietz, Rachel Wiedewitsch, Bhavin Pradhan, Krystal Binversie		
Date Received:	December 31, 2025		

Question:
Topic: Wildfire Mitigation Strategy
Reference(s): 2025 IDP Chapter 2 at 29 – Distribution System Upgrades

1. The Company states it is investing in targeted distribution upgrades to reduce ignition risk.
    a. Are these distribution system upgrades being completed proactively in the targeted areas, or as equipment becomes due for repair/replacement?
    b. Please discuss how the Company prioritizes targeted distribution upgrades.

Response:

a. The targeted distribution system upgrades identified for wildfire risk mitigation are being performed proactively. These upgrades are guided by the Company's Wildfire Risk Map, which identifies areas classified as Wildfire Risk Tier 2 and 3. In these areas, the Company evaluates both inherent wildfire risk and the condition of existing distribution assets. While many upgrades will naturally coincide with assets approaching their repair or replacement cycle, the underlying driver is proactive mitigation of wildfire ignition rather than routine asset renewal alone.
b. Prioritization of targeted distribution upgrades is based first on inherent wildfire risk as shown on the Wildfire Risk Map. Feeders located in Tier 3 areas are addressed before those in Tier 2. Within each tier, the Company incorporates additional factors—including outage history and current distribution asset health—to identify specific conductors, poles, and equipment in need of replacement. This approach is especially relevant for small primary conductor replacement and OPA/PLC remediation work. Collectively, these criteria ensure that upgrades are directed to the locations and assets that present the greatest wildfire-related risk.

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Xcel Energy		Information Request No.	95
Docket No.:	E002/M-25-142		
Response To:	Minnesota Department of Commerce		
Requestor:	Ari Zwick, Diane Dietz, Rachel Wiedewitsch, Bhavin Pradhan, Krystal Binversie		
Date Received:	December 31, 2025		

Question:
Topic: FireSight Application
Reference(s): Sherwood Supplemental Direct at 7-8 – GR-24-320

In its rate case, Sherwood states in Supplemental Direct Testimony that the Company will be utilizing Technosylva's FireSight subscriptions-based information service to determine which assets are most likely to fail, have an outage, and or cause an ignition. This analysis will help Xcel to calculate potential risk reduction for asset hardening projects. The application, states Sherwood:

> *[A]llows Xcel Energy to design mitigation projects to optimize mitigation effectiveness for asset hardening and vegetation management by prioritizing those assets with the highest expected risk by understanding the probability of a wildfire occurring from one asset over another to efficiently prioritize their grid-hardening and mitigation efforts.*[2]

1. Please elaborate further on how the FireSight tool will be utilized by the Company, including a description of the outputs from the tool.
2. What criteria will be utilized to prioritize mitigation projects?
3. How does Xcel intend to calculate potential risk reduction?
4. Could the utility utilize the FireSight tool to develop a portfolio of wildfire mitigation proposals to be filed and reviewed by the Commission? a. Please discuss what a potential portfolio of wildfire mitigation proposals could look like and where such a portfolio could be filed for ultimate Commission review.

[2] *In the Matter of the Application of the Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota*, Sherwood Supplemental Direct Testimony, Xcel Energy, March 17, 2025, Docket No. E002/GR-24-320, (eDockets) 20253-216469-06, at 8.

Response:
Because the FireSight application is subject to the Commission's decision in the pending electric rate case, it is premature for the Company to define how FireSight would be used, what criteria would be applied to prioritize mitigation projects, or how potential risk reduction would be calculated. The Company's ability to procure or

implement FireSight will depend on the level of wildfire-mitigation funding the Commission approves in the pending rate case. Depending on the budget outcome, the Company may or may not move forward with this tool.

For this reason, the Company recommends that the Department defer further inquiry into FireSight's specific functionality or implementation until (1) the wildfire mitigation budget is finalized in the rate case, and (2) the Company files a Wildfire Mitigation Plan that reflects the final approved budget and identifies the specific tools and strategies the Company will deploy. The Department's questions can be more effectively and accurately addressed at that time, once the Commission has issued its decision and the Company is able to present a more fully developed wildfire-mitigation strategy.

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Date:	January 12, 2026

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Xcel Energy		Information Request No.	96
Docket No.:	E002/M-25-142		
Response To:	Minnesota Department of Commerce		
Requestor:	Ari Zwick, Bhavin Pradhan, Adway De, Krystal Binversie		
Date Received:	January 15, 2026		

Question:
Topic: Per-Mile Cost of New Build Overhead VS Underground Distribution Lines
Reference(s): 2025 IDP

Please provide generic, per-mile cost estimates to install a new build typical section of overhead and underground feeders and tap lines.

Response:
Per-mile construction costs for overhead (OH) and underground (UG) distribution construction vary significantly depending on factors such as location (rural vs. metro), construction conditions, need for ducts or conduit, cable or conductor size and material, and local voltage class. In general, "greenfield" construction in rural areas or new subdivisions is less costly than work in dense urban environments, and underground construction is significantly more expensive when duct systems are required.

For underground feeders and taps, recent filings—Part III of the Company's April 1, 2025 filing in Docket No. E002/M-25-27 and Chapter 2 of the Company's October 31, 2025 filing in Docket No. E002/M-25-142—use a typical new-build UG cost estimate of approximately $1.5 million per mile.

For overhead construction, Part III of the Company's April 1, 2025 filing in Docket No. E002/M-25-27 references a $924,000 per-mile cost for overhead line replacement, which includes additional labor and complexity due to existing energized facilities and to minimize planned outages. A typical new-build overhead line, without these replacement-related complexities, is approximately $784,000 per mile, or roughly half the cost of comparable underground construction.

All referenced costs are for typical 15kV distribution construction.

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Telephone:	303-285-6474
Date:	January 26, 2026

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Xcel Energy		Information Request No.	97
Docket No.:	E002/M-25-142		
Response To:	Minnesota Department of Commerce		
Requestor:	Ari Zwick, Bhavin Pradhan, Adway De, Krystal Binversie		
Date Received:	January 15, 2026		

Question:
Topic: Demand Response Programs
Reference(s): 2025 IDP

Xcel outlines several rate programs with controllable load. Please explain if any of these programs can deploy load control at a local level, for example at a single substation or feeder.

Response:
Many of the Company's demand response programs *can* be deployed at a local level, either at a specific substation or an individual feeder—but this is not standard practice. While some programs can only be targeted at the substation level and others offer feeder level control, implementing local dispatch is a highly manual process that requires significant set up time and additional effort to restore normal configurations afterward. Program-specific rules and constraints must also be managed separately for these targeted events.

It is also important to note that the Company's existing demand response programs were primarily designed as tools to support bulk system reliability, not localized grid needs. Shifting a program's use toward more local and targeted deployment would require the Company to evaluate customer agreements and contractual obligations to ensure compliance with established program terms.

Preparer:	Ryan Bruers
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Department:	Demand Management- Product Management
Telephone:	612-321-3186
Date:	January 26, 2026

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Xcel Energy		Information Request No.	100
Docket No.:	E002/M-25-142		
Response To:	Minnesota Department of Commerce		
Requestor:	Ari Zwick, Bhavin Pradhan, Adway De, Krystal Binversie		
Date Received:	February 5, 2026		

Question:
Topic: Frequency of N-1 Events - Update
Reference(s): IR 62

Please provide an updated Attachment A of information request (IR) 62 which includes all of the data presented in IR 62, plus:

A. A timestamp of the start of the outage that includes the hour and minutes.
B. A timestamp of the end of the outage that includes the hour and minutes.

Response:
Please see Attachment A, provided as a Microsoft Excel file with all requested fields, links, and formulae intact.

Attachment A lists all sustained outage events at the feeder and distribution substation level from 2020 through 2024 where contingency switching was used for service restoration. For each event, the file includes the date, cause of the event (equipment that failed), outage duration, and customer minutes of outage. Outage duration is shown as a range, representing the time between the first and last customer restored. Outage timestamps are also provided accordingly.

This list is limited to mainline sustained outages that were partially or fully restored through N-1 contingency capabilities. It does not include planned switching operations, FLISR restorations, or momentary outages where no sustained customer interruptions occurred. Records for those types of events exist but cannot be readily categorized for inclusion in this response. Similarly, events that occurred while adjacent feeds were unavailable or otherwise out of service are excluded. Please note that FLISR restorations are only feasible when N-1 conditions have been planned for and sufficient capacity is available to support the automated load transfer and prevent a sustained outage condition.

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Portions of Attachment A are marked "Not-Public" as it contains information the Company considers to be security information as defined by Minn. Stat. § 13.37(1)(a). The public disclosure or use of this information creates an unacceptable risk because those who want to disrupt the electrical grid for political or other reasons may learn which facilities to target to create the greatest disruption. The Company takes efforts to protect this information from public disclosure. Thus, Xcel Energy excises this information as protected data pursuant to Minn. Rule 7829.0500.

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Telephone:	303-285-6474
Date:	February 17, 2026

CERTIFICATE OF SERVICE

I, Sharon Ferguson, hereby certify that I have this day, served copies of the following document on the attached list of people by electronic filing, certified mail, e-mail, or by depositing a true and correct copy thereof properly enveloped with postage paid in the United States Mail at St. Paul, Minnesota.

Minnesota Department of Commerce
Public Comments

Docket No. E002/M-25-142

Dated this **26th** day of **February 2026**

/s/Sharon Ferguson

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2	Brian	Allen	brian.allen@allenergysolar.com	All Energy Solar, Inc		1642 Carroll Ave Saint Paul MN, 55104 United States	Electronic Service		No	M-25-142
3	Michael	Allen	michael.allen@allenergysolar.com	All Energy Solar		721 W 26th st Suite 211 Minneapolis MN, 55405 United States	Electronic Service		No	M-25-142
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5	Janet	Anderson	jcainstp@icloud.com	-		1799 Sargent St. Paul MN, 55105 United States	Electronic Service		No	M-25-142
6	Jay	Anderson	jaya@cmpas.org	CMPAS		7550 Corporate Way Suite 100 Eden Prairie MN, 55344 United States	Electronic Service		No	M-25-142
7	MK	Anderson	anderson@fresh-energy.org	Fresh Energy		408 St Peter Street Saint Paul MN, 55102 United States	Electronic Service		No	M-25-142
8	David	Assaf	daassaf@flaherty-hood.com	Flaherty & Hood, P.A.		525 Park Street Suite 470 St. Paul MN, 55102 United States	Electronic Service		No	M-25-142
9	Donna	Attanasio	dattanasio@gwu.edu	George Washington University		2000 H Street NW Washington DC, 20052 United States	Electronic Service		No	M-25-142
10	John	Bailey	bailey@ilsr.org	Institute For Local Self-Reliance		1313 5th St SE Ste 303 Minneapolis MN, 55414 United States	Electronic Service		No	M-25-142
11	Anjali	Bains	bains@fresh-energy.org	Fresh Energy		408 Saint Peter Ste 220 Saint Paul MN, 55102 United States	Electronic Service		No	M-25-142
12	Mark	Bakk	mbakk@lcp.coop	Lake Country Power		26039 Bear Ridge Drive Cohasset MN, 55721 United States	Electronic Service		No	M-25-142
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14	Shay	Banton	shayb@irecusa.org	Interstate Renewable Energy Council		600 H Street NE Apt. 341 Washington DC, 20002 United States	Electronic Service		No	M-25-142
15	Laura	Beaton	beaton@smwlaw.com	Shute, Mihaly & Weinberger LLP		396 Hayes Street San Francisco CA, 94102 United States	Electronic Service		No	M-25-142

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17	Jeff	Benson	jbenson@southcentralelectric.com	South Central Electric Association		PO Box 150 71176 Tiell Drive St. James MN, 56081 United States	Electronic Service		No	M-25-142
18	Sasha	Bergman	sasha.bergman@state.mn.us		Public Utilities Commission	121 7th Pl E Ste 350 St. Paul MN, 55101 United States	Electronic Service		Yes	M-25-142
19	Derek	Bertsch	derek.bertsch@mrenergy.com	Missouri River Energy Services		3724 West Avera Drive PO Box 88920 Sioux Falls SD, 57109-8920 United States	Electronic Service		No	M-25-142
20	Barb	Bischoff	barb.bischoff@nngco.com	Northern Natural Gas Co.		CORP HQ, 714 1111 So. 103rd Street Omaha NE, 68124-1000 United States	Electronic Service		No	M-25-142
21	Ingrid	Bjorklund	ibjorklund@avisenlegal.com	Avisen Legal		901 S. Marquette Ave. #1675 Minneapolis MN, 55402 United States	Electronic Service		No	M-25-142
22	Ingrid	Bjorklund	ingrid@bjorklundlaw.com	Bjorklund Law, PLLC		855 Village Center Drive #256 North Oaks MN, 55127 United States	Electronic Service		No	M-25-142
23	William	Black	bblack@mmua.org	MMUA		Suite 200 3131 Fernbrook Lane North Plymouth MN, 55447 United States	Electronic Service		No	M-25-142
24	Kenneth	Bradley	kbradley@environmentminnesota.org			2837 Emerson Ave S Apt CW112 Minneapolis MN, 55408 United States	Electronic Service		No	M-25-142
25	Jon	Brekke	jbrekke@grenergy.com	Great River Energy		12300 Elm Creek Boulevard Maple Grove MN, 55369-4718 United States	Electronic Service		No	M-25-142
26	Kathleen	Brennan	kbrennan@spencerfane.com	Spencer Fane LLP		100 South Fifth Street, Suite 2500 Minneapolis MN, 55402 United States	Electronic Service		No	M-25-142
27	Sydney R.	Briggs	sbriggs@swce.coop	Steele-Waseca Cooperative Electric		2411 W. Bridge St PO Box 485 Owatonna MN, 55060-0485 United States	Electronic Service		No	M-25-142
28	Mark B.	Bring	mbring@otpco.com	Otter Tail Power Company		215 South Cascade Street	Electronic Service		No	M-25-142

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30	Ed	Brolin	ed.brolin@rwe.com	RWE Clean Energy		100 Summit Lake Drive Suite 210 Valhalla NY, 10595 United States	Electronic Service		No	M-25-142
31	Christopher	Browning	christopher.browning@nexteraenergy.com			null null, null United States	Electronic Service		No	M-25-142
32	Christina	Brusven	cbrusven@fredlaw.com	Fredrikson Byron		60 S 6th St Ste 1500 Minneapolis MN, 55402-4400 United States	Electronic Service		No	M-25-142
33	Mike	Bull	mike.bull@state.mn.us		Public Utilities Commission	121 7th Place East, Suite 350 St. Paul MN, 55101 United States	Electronic Service		Yes	M-25-142
34	Jerry	Byer	jbyer@itasca-mantrap.com	Itasca-Mantrap Electric Cooperative		PO Box 192 Park Rapids MN, 56470 United States	Electronic Service		No	M-25-142
35	Jennifer	Cady	jjcady@mnpower.com	Minnesota Power		30 W Superior St Duluth MN, 55802 United States	Electronic Service		No	M-25-142
36	Daniel T	Carlisle	todd-wad@toddwadena.coop	Todd-Wadena Electric Cooperative		550 Ash Ave NE PO Box 431 Wadena MN, 56482 United States	Electronic Service		No	M-25-142
37	Douglas M.	Carnival	dcarnival@carnivalberns.com	McGrann Shea Carnival Straughn & Lamb		800 Nicollet Mall Ste 2600 Minneapolis MN, 55402-7035 United States	Electronic Service		No	M-25-142
38	Pat	Carruth	pat@mnvalleyrec.com	Minnesota Valley Coop. Light & Power Assn.		501 S 1st St. PO Box 248 Montevideo MN, 56265 United States	Electronic Service		No	M-25-142
39	Gabriel	Chan	gabechan@umn.edu			130 Hubert H. Humphrey Center 301 19th Ave S Minneapolis MN, 55455 United States	Electronic Service		No	M-25-142
40	Ray	Choquette	rchoquette@agp.com	Ag Processing Inc.		12700 West Dodge Road PO Box 2047 Omaha NE, 68103-2047 United States	Electronic Service		No	M-25-142
41	Eric	Clement	eclement@mnpower.com	Minnesota Power		null null, null United States	Electronic Service		No	M-25-142
42	City	Clerk	gregg.engdahl@ci.stcloud.mn.us	City of St. Cloud		400 Second St. S	Electronic Service		No	M-25-142

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44	Kenneth A.	Colburn	kcolburn@symbioticstrategies.com	Symbiotic Strategies, LLC		26 Winton Road Meredith NH, 32535413 United States	Electronic Service		No	M-25-142
45	Steve	Coleman	stevecolemanpuma@gmail.com			231 Winifred St W Saint Paul MN, 55107 United States	Electronic Service		No	M-25-142
46	Generic	Commerce Attorneys	commerce.attorneys@ag.state.mn.us		Office of the Attorney General - Department of Commerce	445 Minnesota Street Suite 1400 St. Paul MN, 55101 United States	Electronic Service		Yes	M-25-142
47	Kevin	Cray	kevin@communitysolaraccess.org	CCSA		1644 Platte St Denver CO, 80202 United States	Electronic Service		No	M-25-142
48	George	Crocker	gwillc@nawo.org	North American Water Office		5093 Keats Avenue Lake Elmo MN, 55042 United States	Electronic Service		No	M-25-142
49	Stacy	Dahl	sdahl@minnkota.com	Minnkota Power Cooperative, Inc.		5301 32nd Ave S Grand Forks ND, 58201 United States	Electronic Service		No	M-25-142
50	George	Damian	gdamian@cleanenergyeconomymn.org	Clean Energy Economy MN		13713 Washburn Ave S Burnsville MN, 55337 United States	Electronic Service		No	M-25-142
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52	James	Darabi	james.darabi@solarfarm.com			2355 Fairview Ave #101 St. Paul MN, 55113 United States	Electronic Service		No	M-25-142
53	Cody	Davis	cdavis@epeconsulting.com	Electric Power Engineers (ELPC/VS)		null null, null United States	Electronic Service		No	M-25-142
54	Danielle	DeMarre	danielle.demarre@allenergysolar.com	All Energy Solar		1264 Energy Lane St Paul MN, 55108 United States	Electronic Service		No	M-25-142
55	Timothy	DenHerder Thomas	timothy@cooperativeenergyfutures.com	Cooperative Energy Futures		3500 Bloomington Ave. S Minneapolis MN, 55407 United States	Electronic Service		No	M-25-142
56	James	Denniston	james.r.denniston@xcelenergy.com	Xcel Energy Services, Inc.		414 Nicollet Mall, 401-8 Minneapolis MN, 55401 United States	Electronic Service		No	M-25-142

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
57	Carrie	Desmond	carrie.desmond@metrotransit.org	Metropolitan Council		560 6th Avenue North Minneapolis MN, 55411 United States	Electronic Service		No	M-25-142
58	Curt	Dieren	curt.dieren@dgr.com	L&O Power Cooperative		1302 S Union St Rock Rapids IA, 51246 United States	Electronic Service		No	M-25-142
59	Cheryl	Dietrich	cheryl.dietrich@nexteraenergy.com	NextEra Energy Resources, LLC		700 Universe Blvd E1W/JB Juno Beach FL, 33408 United States	Electronic Service		No	M-25-142
60	Diane	Dietz	diane.dietz@state.mn.us		Department of Commerce	Suite 280 85 Seventh Place East St. Paul MN, 55101-2198 United States	Electronic Service		No	M-25-142
61	Ian M.	Dobson	ian.m.dobson@xcelenergy.com	Xcel Energy		414 Nicollet Mall, 401-8 Minneapolis MN, 55401 United States	Electronic Service		No	M-25-142
62	Kristin	Dolan	kdolan@meeker.coop	Meeker Cooperative Light & Power Assn		1725 US Hwy 12 E. Ste 100 Litchfield MN, 55355 United States	Electronic Service		No	M-25-142
63	Renee	Doyle	guydoyleelectric@gmail.com	Doyle Electric Inc.		PO Box 295 Amboy MN, 56010 United States	Electronic Service		No	M-25-142
64	Carlon	Doyle Fontaine	carlon.doyle.fontaine@senate.mn	MN Senate		75 Rev Dr Martin Luther King Jr Blvd Room G-17 St Paul MN, 55155 United States	Electronic Service		No	M-25-142
65	Adam	Duininck	aduininck@ncsrcc.org	North Central States Regional Council of Carpenters		700 Olive Street St. Paul MN, 55130 United States	Electronic Service		No	M-25-142
66	Scott	Dunbar	sdunbar@kfwlaw.com	Keyes & Fox LLP		1580 Lincoln St Ste 880 Denver CO, 80203 United States	Electronic Service		No	M-25-142
67	John R.	Dunlop, P.E.	jdunlop@resminn.com	Renewable Energy Services		Suite 300 448 Morgan Ave. S. Minneapolis MN, 55405-2030 United States	Electronic Service		No	M-25-142
68	Hannah	Dunn	hannah.dunn@oakdalemn.gov	City of Oakdale		1584 Hadley Ave N Oakdale MN, 55104 United States	Electronic Service		No	M-25-142
69	Kelly	Dybdahl	kdybdahl@llec.coop	Lyon-Lincoln Electric Cooperative, Inc.		205 W. Hwy. 14 Tyler MN, 56178 United States	Electronic Service		No	M-25-142
70	Brian	Edstrom	briane@cubminnesota.org	Citizens Utility Board of Minnesota		332 Minnesota St Ste W1360 Saint Paul MN, 55101 United States	Electronic Service		No	M-25-142
71	Dick	Edwards	dedwards@ci.maple-grove.mn.us	City of Maple Grove		12800 Arbor Lakes Parkway	Electronic Service		No	M-25-142

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
						P O Box 1180 Maple Grove MN, 55311-6180 United States				
72	William	Ehrlich	wehrlich@tesla.com	Tesla, Inc.		3500 Deer Creek Rd Palo Alto CA, 94304 United States	Electronic Service		No	M-25-142
73	Kristen	Eide Tollefson	healingsystems69@gmail.com	R-CURE		28477 N Lake Ave Frontenac MN, 55026-1044 United States	Electronic Service		No	M-25-142
74	Bob	Eleff	bob.eleff@house.mn	Regulated Industries Cmte		100 Rev Dr Martin Luther King Jr Blvd Room 600 St. Paul MN, 55155 United States	Electronic Service		No	M-25-142
75	R. Neal	Elliot	rnelliott@aceee.org	American Council for an Energy-Efficient Economy		ACEEE 529 14th St NW Ste 600 Washington DC, 20045 United States	Electronic Service		No	M-25-142
76	Nadav	Enbar	nenbar@epri.com	EPRI		1117 Quince Ave Boulder CO, 80304 United States	Electronic Service		No	M-25-142
77	John	Farrell	jfarrell@ilsr.org	Institute for Local Self-Reliance		2720 E. 22nd St Institute for Local Self-Reliance Minneapolis MN, 55406 United States	Electronic Service		No	M-25-142
78	Christian	Fenstermacher	christian.fenstermacher@owatonnautilities.com	Owatonna Municipal Public Utilities		PO Box 800 208 S Walnut Ave Owatonna MN, 55060 United States	Electronic Service		No	M-25-142
79	Sharon	Ferguson	sharon.ferguson@state.mn.us		Department of Commerce	85 7th Place E Ste 280 Saint Paul MN, 55101-2198 United States	Electronic Service		No	M-25-142
80	Christine	Fox	cfox@itasca-mantrap.com	Itasca-Mantrap Coop. Electric Assn.		PO Box 192 Park Rapids MN, 56470 United States	Electronic Service		No	M-25-142
81	Kornbaum	Frank	fkornbaum@mnpower.com			null null, null United States	Electronic Service		No	M-25-142
82	Nathan	Franzen	nathan@nationalgridrenewables.com	Geronimo Energy, LLC		8400 Normandale Lake Blvd Ste 1200 Bloomington MN, 55437 United States	Electronic Service		No	M-25-142
83	David	Freestate	dfreestate@epri.com	EPRI		942 Corridor Park Blvd Knoxville TN, 37932 United States	Electronic Service		No	M-25-142
84	Katelyn	Frye	kfrye@mnpower.com	Minnesota Power		30 W Superiot St Duluth MN, 55802-2093 United States	Electronic Service		No	M-25-142

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
85	Jessica	Fyhrie	jfyhrie@otpco.com	Otter Tail Power Company		PO Box 496 Fergus Falls MN, 56538-0496 United States	Electronic Service		No	M-25-142
86	Edward	Garvey	garveyed@aol.com	Residence		32 Lawton St Saint Paul MN, 55102 United States	Electronic Service		No	M-25-142
87	Allen	Gleckner	agleckner@elpc.org	Environmental Law & Policy Center		35 E. Wacker Drive, Suite 1600 Suite 1600 Chicago IL, 60601 United States	Electronic Service		No	M-25-142
88	Jenny	Glumack	jenny@mrea.org	Minnesota Rural Electric Association		11640 73rd Ave N Maple Grove MN, 55369 United States	Electronic Service		No	M-25-142
89	Sean	Gosiewski	sean@afors.org	Alliance for Sustainability		2801 21st Ave S Ste 100 Minneapolis MN, 55407 United States	Electronic Service		No	M-25-142
90	Scott	Greenbert	scott@nautilussolar.com	Nautilus Solar Energy, LLC		396 Springfield Aver, Ste 2 Summit NJ, 07901 United States	Electronic Service		No	M-25-142
91	Sarah	Groebner	sgroebner@redwoodelectric.com	Redwood Electric Cooperative		60 Pine St Clements MN, 56224 United States	Electronic Service		No	M-25-142
92	Tim	Gross	tgross@fuelingmn.com	Fueling Minnesota		3244 Rice Street St. Paul MN, 55126 United States	Electronic Service		No	M-25-142
93	Cody	Gustafson	cgustafson@mnpower.com			null null, null United States	Electronic Service		No	M-25-142
94	Tom	Guttormson	tom.guttormson@connexusenergy.com	Connexus Energy		14601 Ramsey Blvd Ramsey MN, 55303 United States	Electronic Service		No	M-25-142
95	Natalie	Haberman	townsend@fresh-energy.org	Fresh Energy		408 St Peter St # 350 St. Paul MN, 55102 United States	Electronic Service		No	M-25-142
96	Nicholas	Haeg	haeg@fresh-energy.org			12298 Bass Trail Sauk Centre MN, 56378 United States	Electronic Service		No	M-25-142
97	James	Haler	jhaler@southcentralelectric.com	South Central Electric Association		71176 Tiell Dr P. O. Box 150 St. James MN, 56081 United States	Electronic Service		No	M-25-142
98	Joe	Halso	joe.halso@sierraclub.org	Sierra Club		1536 Wynkoop St Ste 200 Denver CO, 80202 United States	Electronic Service		No	M-25-142
99	Donald	Hanson	dfhanson@ieee.org			P. O. Box 44579 Eden Prairie MN, 55344 United States	Electronic Service		No	M-25-142
100	John	Harlander	john.c.harlander@xcelenergy.com	Xcel Energy		null null, null	Electronic Service		No	M-25-142

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
						United States				
101	Kim	Havey	kim.havey@minneapolismn.gov	City of Minneapolis		350 South 5th Street, Suite 315M Minneapolis MN, 55415 United States	Electronic Service		No	M-25-142
102	Todd	Headlee	theadlee@dvigridsolutions.com	Dominion Voltage, Inc.		701 E. Cary Street Richmond VA, 23219 United States	Electronic Service		No	M-25-142
103	Amber	Hedlund	amber.r.hedlund@xcelenergy.com	Northern States Power Company dba Xcel Energy-Elec		414 Nicollet Mall, 401-7 Minneapolis MN, 55401 United States	Electronic Service		No	M-25-142
104	Tiana	Heger	theger@mnpower.com	Minnesota Power		30 W. Superior Street Duluth MN, 55802 United States	Electronic Service		No	M-25-142
105	Adam	Heinen	aheinen@dakotaelectric.com	Dakota Electric Association		4300 220th St W Farmington MN, 55024 United States	Electronic Service		No	M-25-142
106	Annete	Henkel	mui@mnutilityinvestors.org	Minnesota Utility Investors		413 Wacouta Street #230 St.Paul MN, 55101 United States	Electronic Service		No	M-25-142
107	Jessy	Hennesy	jessy.hennesy@avantenergy.com	Avant Energy		220 S. Sixth St. Ste 1300 Minneapolis MN, 55402 United States	Electronic Service		No	M-25-142
108	Mari	Hernandez	mari@irecusa.org	IREC		null null, null United States	Electronic Service		No	M-25-142
109	Katherine	Hinderlie	katherine.hinderlie@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	445 Minnesota St Suite 1400 St. Paul MN, 55101-2134 United States	Electronic Service		No	M-25-142
110	Joe	Hoffman	ja.hoffman@smmpa.org	SMMPA		500 First Ave SW Rochester MN, 55902-3303 United States	Electronic Service		No	M-25-142
111	Michael	Hoppe	lu23@ibew23.org	Local Union 23, I.B.E.W.		445 Etna Street Ste. 61 St. Paul MN, 55106 United States	Electronic Service		No	M-25-142
112	Casey	Horan	choran@edf.org	Environmental Defense Fund		123 Mission St San Francisco CA, 94105 United States	Electronic Service		No	M-25-142
113	Ronald	Horman	rhorman@redwoodelectric.com	Redwood Electric Cooperative		60 Pine Street Clements MN, 56224 United States	Electronic Service		No	M-25-142
114	Frank	Hornstein	frank.hornstein@minneapolismn.gov	City of Minneapolis		350 South 5th Street Minneapolis MN, 55415 United States	Electronic Service		No	M-25-142
115	Samantha	Houston	shouston@ucsusa.org	Union of Concerned Scientists		1825 K St. NW Ste 800 Washington	Electronic Service		No	M-25-142

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
						DC, 20006 United States				
116	Lori	Hoyum	lhoyum@mnpower.com	Minnesota Power		30 West Superior Street Duluth MN, 55802 United States	Electronic Service		No	M-25-142
117	Jan	Hubbard	jan.hubbard@comcast.net			7730 Mississippi Lane Brooklyn Park MN, 55444 United States	Electronic Service		No	M-25-142
118	Dean	Hunter	dean.hunter@state.mn.us		Minnesota Department of Labor & Industry	443 Lafayette Rd N St. Paul MN, 55155-4341 United States	Electronic Service		No	M-25-142
119	Reuben	Hunter	bhunter@madisonei.com	Madison Energy Investments		8100 Boone Blvd Suite 430 Vienna VA, 22182 United States	Electronic Service		No	M-25-142
120	Casey	Jacobson	cjacobson@bepc.com	Basin Electric Power Cooperative		1717 East Interstate Avenue Bismarck ND, 58501 United States	Electronic Service		No	M-25-142
121	John S.	Jaffray	jjaffray@jjrpower.com	JJR Power		350 Highway 7 Suite 236 Excelsior MN, 55331 United States	Electronic Service		No	M-25-142
122	Robert	Jagusch	rjagusch@mmua.org	MMUA		3025 Harbor Lane N Minneapolis MN, 55447 United States	Electronic Service		No	M-25-142
123	Chris	Jarosch	chris@carrcreekelectricservice.com	Carr Creek Electric Service, LLC		209 Sommers Street North Hudson WI, 54016 United States	Electronic Service		No	M-25-142
124	Alan	Jenkins	aj@jenkinsatlaw.com	Jenkins at Law		2950 Yellowtail Ave. Marathon FL, 33050 United States	Electronic Service		No	M-25-142
125	Richard	Johnson	rickjohnson@cozen.com	Cozen O'Connor		150 S. 5th Street Suite 1200 Minneapolis MN, 55402 United States	Electronic Service		No	M-25-142
126	Sarah	Johnson Phillips	sjphillips@stoel.com	Stoel Rives LLP		33 South Sixth Street Suite 4200 Minneapolis MN, 55402 United States	Electronic Service		No	M-25-142
127	Nate	Jones	njones@hcpd.com	Heartland Consumers Power		PO Box 248 Madison SD, 57042 United States	Electronic Service		No	M-25-142
128	Philip	Jones	phil@evtransportationalliance.org			1402 Third Ave Ste 1315 Seattle WA, 98101 United States	Electronic Service		No	M-25-142
129	Julie	Jorgensen	julie@greenmark.us.com	Greenmark Solar		4630 Quebec Ave N New Hope MN, 55428-4973 United States	Electronic Service		No	M-25-142

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
130	Kevin	Joyce	kjoyce@tesla.com			null null, null United States	Electronic Service		No	M-25-142
131	Mahmoud	Kabalan	mahmoud.kabalan@stthomas.edu	University of St Thomas		2115 Summit Ave. Mail OSS100 School of Engineering Saint Paul MN, 55105 United States	Electronic Service		No	M-25-142
132	Camille	Kadoch	ckadoch@raponline.org	Regulatory Assistance Project		50 State Street Suite 3 Montpelier VT, 05602 United States	Electronic Service		No	M-25-142
133	Cliff	Kaehler	cliff.kaehler@novelenergy.biz	Novel Energy Solutions LLC		4710 Blaylock Way Inver Grove Heights MN, 55076 United States	Electronic Service		No	M-25-142
134	Ralph	Kaehler	ralph.kaehler@gmail.com			13700 Co. Rd. 9 Eyota MN, 55934 United States	Electronic Service		No	M-25-142
135	Michael	Kampmeyer	mkampmeyer@a-e-group.com	AEG Group, LLC		260 Salem Church Road Sunfish Lake MN, 55118 United States	Electronic Service		No	M-25-142
136	Nick	Kaneski	nick.kaneski@enbridge.com	Enbridge Energy Company, Inc.		11 East Superior St Ste 125 Duluth MN, 55802 United States	Electronic Service		No	M-25-142
137	Jack	Kegel	jkegel@mmua.org	MMUA		3025 Harbor Lane N Suite 400 Plymouth MN, 55447-5142 United States	Electronic Service		No	M-25-142
138	William	Kenworthy	will@votesolar.org			1 South Dearborn St Ste 2000 Chicago IL, 60603 United States	Electronic Service		No	M-25-142
139	Samuel B.	Ketchum	sketchum@kennedy-graven.com	Kennedy & Graven, Chartered		150 S 5th St Ste 700 Minneapolis MN, 55402 United States	Electronic Service		No	M-25-142
140	Tom	Key	tkey@epri.com	EPRI		942 Corridor Park Blvd Knoxville TN, 37932 United States	Electronic Service		No	M-25-142
141	Bobby	King	bking@solarunitedneighbors.org	Solar United Neighbors		3140 43rd Ave S Minneapolis MN, 55406 United States	Electronic Service		No	M-25-142
142	Jack	Kluempke	jack.kluempke@state.mn.us		Department of Commerce	85 7th Place East Suite 600 St. Paul MN, 55101 United States	Electronic Service		No	M-25-142
143	Aaron	Knoll	aknoll@greeneespel.com	Greene Espel PLLP		222 South Ninth Street Suite 2200 Minneapolis MN, 55402 United States	Electronic Service		No	M-25-142

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
144	Steve	Kosbab	skosbab@meeker.coop	Meeker Cooperative Light and Power		1725 US Hwy 12 E Litchfield MN, 55355 United States	Electronic Service		No	M-25-142
145	Nathan	Kostiuk	nathan.c.kostiuk@xcelenergy.com	Xcel Energy		414 Nicollet Mall, 401-07 Minneapolis MN, 55401 United States	Electronic Service		No	M-25-142
146	Brian	Krambeer	bkrambeer@mienergy.coop	MiEnergy Cooperative		PO Box 626 31110 Cooperative Way Rushford MN, 55971 United States	Electronic Service		No	M-25-142
147	Michael	Krause	michaelkrause61@yahoo.com			1200 Plymouth Avenue Minneapolis MN, 55411 United States	Electronic Service		No	M-25-142
148	Michael	Krikava	mkrikava@taftlaw.com	Taft Stettinius & Hollister LLP		2200 IDS Center 80 S 8th St Minneapolis MN, 55402 United States	Electronic Service		No	M-25-142
149	Corrina	Kumpe	ckumpe@mysunshare.com			null null, null United States	Electronic Service		No	M-25-142
150	Matthew	Lacey	mlacey@grenergy.com	Great River Energy		12300 Elm Creek Boulevard Maple Grove MN, 55369-4718 United States	Electronic Service		No	M-25-142
151	James D.	Larson	james.larson@avantenergy.com	Avant Energy Services		220 S 6th St Ste 1300 Minneapolis MN, 55402 United States	Electronic Service		No	M-25-142
152	Mark	Larson	mlarson@meeker.coop	Meeker Coop Light & Power Assn		1725 Highway 12 E Ste 100 Litchfield MN, 55355 United States	Electronic Service		No	M-25-142
153	Burnell	Lauer	blauer.sundial@gmail.com	Sundial Solar		3209 W. 76th St #305 Edina MN, 55435 United States	Electronic Service		No	M-25-142
154	Dean	Leischow	dean@sunrisenrg.com	Sunrise Energy Ventures		315 Manitoba Ave Ste 200 Wayzata MN, 55391 United States	Electronic Service		No	M-25-142
155	Annie	Levenson Falk	annielf@cubminnesota.org	Citizens Utility Board of Minnesota		332 Minnesota Street, Suite W1360 St. Paul MN, 55101 United States	Electronic Service		No	M-25-142
156	Benjamin	Levine	blevine@mnpower.com	Minnesota Power		30 West Superior Street Duluth MN, 55802 United States	Electronic Service		No	M-25-142
157	Becky	Li	bli@rmi.org			17 State St 25th floor unit 2500 New York NY, 10004 United States	Electronic Service		No	M-25-142

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
158	Amy	Liberkowski	amy.a.liberkowski@xcelenergy.com	Xcel Energy		414 Nicollet Mall 7th Floor Minneapolis MN, 55401-1993 United States	Electronic Service		No	M-25-142
159	Carl	Linvill	clinvill@raponline.org			50 State Street Suite #3 Montpelier VT, 05602 United States	Electronic Service		No	M-25-142
160	Phillip	Lipetsky	greenenergyproductsllc@gmail.com	Green Energy Products		PO Box 108 Springfield MN, 56087 United States	Electronic Service		No	M-25-142
161	Jody	Londo	jody.l.londo@xcelenergy.com	Xcel Energy		414 Nicillet Mall 7th Floor Minneapolis MN, 55401-1993 United States	Electronic Service		No	M-25-142
162	Susan	Ludwig	sludwig@mnpower.com	Minnesota Power		30 West Superior Street Duluth MN, 55802 United States	Electronic Service		No	M-25-142
163	Brian	Lydic	brian@irecusa.org	Interstate Renewable Energy Council, Inc.		PO Box 1156 Latham NY, 12110-1156 United States	Electronic Service		No	M-25-142
164	Madeline	Lydon	madeline.k.lydon@xcelenergy.com	Xcel Energy		401 NICOLLET MALL Floor 7 Minneapolis MN, 55401 United States	Electronic Service		No	M-25-142
165	Richard	Macke	macker@powersystem.org	Power System Engineering, Inc.		10710 Town Square Dr NE Ste 201 Minneapolis MN, 55449 United States	Electronic Service		No	M-25-142
166	Alice	Madden	alice@communitypowermn.org	Community Power		2720 E 22nd St Minneapolis MN, 55406 United States	Electronic Service		No	M-25-142
167	Alex	Magerko	amagerko@epri.com	EPRI		942 Corridor Park Blvd Knoxville TN, 37932 United States	Electronic Service		No	M-25-142
168	Kavita	Maini	kmaini@wi.rr.com	KM Energy Consulting, LLC		961 N Lost Woods Rd Oconomowoc WI, 53066 United States	Electronic Service		No	M-25-142
169	Tom	Mammen	thomas.j.mammen@xcelenergy.com	Xcel Energy		null null, null United States	Electronic Service		No	M-25-142
170	Discovery	Manager	discoverymanager@mnpower.com	Minnesota Power		30 W Superior St Duluth MN, 55802 United States	Electronic Service		No	M-25-142
171	Christine	Marquis	regulatory.records@xcelenergy.com	Xcel Energy		414 Nicollet Mall MN1180-07-MCA Minneapolis MN, 55401 United States	Electronic Service		Yes	M-25-142

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
172	Gregg	Mast	gmast@cleanenergyeconomymn.org	Clean Energy Economy Minnesota		4808 10th Avenue S Minneapolis MN, 55417 United States	Electronic Service		No	M-25-142
173	Jason	Maur	jason.maur@renesolapower.com	Renesola Power Holdings, LLC		850 Canal Street 3rd Floor Stamford CT, 06902 United States	Electronic Service		No	M-25-142
174	Erica	McConnell	emcconnell@elpc.org	Environmental Law & Policy Center		35 E. Wacker Drive, Suite 1600 Chicago IL, 60601 United States	Electronic Service		No	M-25-142
175	Jess	McCullough	jmccullough@mnpower.com	Minnesota Power		30 W Superior St Duluth MN, 55802 United States	Electronic Service		No	M-25-142
176	Sara G	McGrane	smcgrane@felhaber.com	Felhaber Larson		220 S 6th St Ste 2200 Minneapolis MN, 55420 United States	Electronic Service		No	M-25-142
177	Natalie	McIntire	natalie.mcintire@gmail.com	Wind on the Wires		570 Asbury St Ste 201 Saint Paul MN, 55104-1850 United States	Electronic Service		No	M-25-142
178	Matthew	Melewski	matthew@theboutiquefirm.com	Nokomis Energy LLC & Ole Solar LLC		2639 Nicollet Ave Ste 200 Minneapolis MN, 55408 United States	Electronic Service		No	M-25-142
179	Thomas	Melone	thomas.melone@allcous.com	Minnesota Go Solar LLC		222 South 9th Street Suite 1600 Minneapolis MN, 55120 United States	Electronic Service		No	M-25-142
180	Michael	Menzel	mike.m@sagiliti.com	Sagiliti		23505 Smithtown Rd. Suite 280 Excelsior MN, 55331 United States	Electronic Service		No	M-25-142
181	Tim	Mergen	tmergen@meeker.coop	Meeker Cooperative Light And Power		1725 US Hwy 12 E. Suite 100 PO Box 68 Litchfield MN, 55355 United States	Electronic Service		No	M-25-142
182	Pontius	Mike	mpontius@mnpower.com			null null, null United States	Electronic Service		No	M-25-142
183	Brian	Millberg	fwengineering@comcast.net			695 Grand AVe #222 Saint Paul MN, 55105 United States	Electronic Service		No	M-25-142
184	Luther	Miller	luther.c.miller@xcelenergy.com	Xcel Energy		null null, null United States	Electronic Service		No	M-25-142
185	Marc	Miller	mmiller@soltage.com	Soltage, LLC		66 York Street, 5th Floor Jersey City NJ, 07302 United States	Electronic Service		No	M-25-142
186	Marcus	Mills	marcus@communitypowermn.org	Community Power		2720 E 22nd St	Electronic Service		No	M-25-142

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
						Minneapolis MN, 55406 United States				
187	Darrick	Moe	darrick@mrea.org	Minnesota Rural Electric Association		11640 73rd Ave N Maple Grove MN, 55369 United States	Electronic Service		No	M-25-142
188	Dalene	Monsebroten	dalene.monsebroten@nmpagency.com	Northern Municipal Power Agency		123 2nd St W Thief River Falls MN, 56701 United States	Electronic Service		No	M-25-142
189	Brian	Monson	brian.t.monson@xcelenergy.com	Xcel Energy		null null, null United States	Electronic Service		No	M-25-142
190	Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP		33 South Sixth St Ste 4200 Minneapolis MN, 55402 United States	Electronic Service		No	M-25-142
191	Susan	Mudd	smudd@elpc.org	Environmental Law and Policy Center		35 E. Wacker Drive, Suite 1600 Chicago IL, 60601 United States	Electronic Service		No	M-25-142
192	Pouya	Najmaie	najm0001@gmail.com	Cooperative Energy Futures		3416 16th Ave S Minneapolis MN, 55407 United States	Electronic Service		No	M-25-142
193	Alex	Nelson	anelson@dakotaelectric.com	Dakota Electric Association		4300 220nd St Farmington MN, 55024 United States	Electronic Service		No	M-25-142
194	Anthony	Nelson	amnelson@otpco.com	Ottertail Power		53233 Sunrise Ln Park Rapids MN, 56470 United States	Electronic Service		No	M-25-142
195	Ben	Nelson	benn@cmpasgroup.org	CMMPA		459 South Grove Street Blue Earth MN, 56013 United States	Electronic Service		No	M-25-142
196	Carl	Nelson	cnelson@mncee.org	Center for Energy and Environment		212 3rd Ave N Ste 560 Minneapolis MN, 55401 United States	Electronic Service		No	M-25-142
197	Darin	Nelson	dnelson@minnetonkamn.gov	City of Minnetonka		14600 Minnetonka Blvd Minnetonka MN, 55345 United States	Electronic Service		No	M-25-142
198	David	Niles	david.niles@avantenergy.com	Minnesota Municipal Power Agency		220 South Sixth Street Suite 1300 Minneapolis MN, 55402 United States	Electronic Service		No	M-25-142
199	Sephra	Ninow	sephra.ninow@energycenter.org	Center for Sustainable Energy		426 17th Street, Suite 700 Oakland CA, 94612 United States	Electronic Service		No	M-25-142
200	Michael	Noble	noble@fresh-energy.org	Fresh Energy		408 Saint Peter St Ste 350 Saint Paul MN, 55102 United States	Electronic Service		No	M-25-142

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
201	Rolf	Nordstrom	rnordstrom@gpisd.net	Great Plains Institute		2801 21ST AVE S STE 220 Minneapolis MN, 55407-1229 United States	Electronic Service		No	M-25-142
202	Samantha	Norris	samanthanorris@alliantenergy.com	Interstate Power and Light Company		200 1st Street SE PO Box 351 Cedar Rapids IA, 52406-0351 United States	Electronic Service		No	M-25-142
203	David	O'Brien	david.obrien@navigant.com	Navigant Consulting		77 South Bedford St Ste 400 Burlington MA, 01803 United States	Electronic Service		No	M-25-142
204	Logan	O'Grady	logrady@mnseia.org	Minnesota Solar Energy Industries Association		2288 University Ave W St. Paul MN, 55114 United States	Electronic Service		No	M-25-142
205	Patty	O'Keefe	patty.okeefe@sierraclub.org			2525 Emerson Ave S Apt 2 Minneapolis MN, 55405 United States	Electronic Service		No	M-25-142
206	Timothy	O'Leary	toleary@llec.coop	Lyon-Lincoln Electric Cooperative, Inc		P.O. Box 639 Tyler MN, 56178-0639 United States	Electronic Service		No	M-25-142
207	Jeff	O'Neill	jeff.oneill@ci.monticello.mn.us	City of Monticello		505 Walnut Street Suite 1 Monticelllo MN, 55362 United States	Electronic Service		No	M-25-142
208	Matthew	Olsen	molsen@otpco.com	Otter Tail Power Company		215 South Cascade Street Fergus Falls MN, 56537 United States	Electronic Service		No	M-25-142
209	Russell	Olson	rolson@hcpd.com	Heartland Consumers Power District		PO Box 248 Madison SD, 57042-0248 United States	Electronic Service		No	M-25-142
210	Wendi	Olson	wolson@otpco.com	Otter Tail Power Company		215 South Cascade Fergus Falls MN, 56537 United States	Electronic Service		No	M-25-142
211	Carol A.	Overland	overland@legalectric.org	Legalectric - Overland Law Office		1110 West Avenue Red Wing MN, 55066 United States	Electronic Service		No	M-25-142
212	Bethany	Owen	bowen@mnpower.com	Minnesota Power		30 West Superior Street Duluth MN, 55802 United States	Electronic Service		No	M-25-142
213	Cezar	Panait	cezar.panait@state.mn.us		Public Utilities Commission	121 7th Place East Suite 350 St. Paul MN, 55101 United States	Electronic Service		No	M-25-142

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
214	Dan	Patry	dpatry@sunedison.com	SunEdison		600 Clipper Drive Belmont CA, 94002 United States	Electronic Service		No	M-25-142
215	Jeffrey C	Paulson	jeff.jcplaw@comcast.net	Paulson Law Office, Ltd.		4445 W 77th Street Suite 224 Edina MN, 55435 United States	Electronic Service		No	M-25-142
216	Dean	Pawlowski	dpawlowski@otpco.com	Otter Tail Power Company		PO Box 496 215 S. Cascade St. Fergus Falls MN, 56537-0496 United States	Electronic Service		No	M-25-142
217	Susan	Peirce	susan.peirce@state.mn.us		Department of Commerce	85 Seventh Place East St. Paul MN, 55101 United States	Electronic Service		No	M-25-142
218	Mary Beth	Peranteau	mperanteau@fredlaw.com	Fredrikson & Byron, P.A.		44 East Mifflin Street Suite 1000 Madison WI, 53703 United States	Electronic Service		No	M-25-142
219	Jennifer	Peterson	jjpeterson@mnpower.com	Minnesota Power		30 West Superior Street Duluth MN, 55802 United States	Electronic Service		No	M-25-142
220	Wess	Pfaff	wes.pfaff@mrenergy.com			null null, null United States	Electronic Service		No	M-25-142
221	Ryan	Pierce	ryan.m.pierce@xcelenergy.com	Xcel Energy		null null, null United States	Electronic Service		No	M-25-142
222	Morgan	Pitz	morgan.pitz@us-solar.com	US Solar		100 N 6th St #410B Minneapolis MN, 55403 United States	Electronic Service		No	M-25-142
223	Hannah	Polikov	hpolikov@aee.net	Advanced Energy Economy Institute		1000 Vermont Ave, Third Floor Washington DC, 20005 United States	Electronic Service		No	M-25-142
224	Crystal	Pomerleau	crystal.r.pomerleau@xcelenergy.com	Xcel		null null, null United States	Electronic Service		No	M-25-142
225	Kristel	Porter	kristel@mnrenewablenow.org	MN Renewable Now		null null, null United States	Electronic Service		No	M-25-142
226	Paula	Prahl	paula.prahl@dominiuminc.com	Dominium		2905 Northwest Blvd Ste 150 Plymouth MN, 55441 United States	Electronic Service		No	M-25-142
227	Kevin	Pranis	kpranis@liunagroc.com	Laborers' District Council of MN and ND		81 E Little Canada Road St. Paul MN, 55117 United States	Electronic Service		No	M-25-142
228	David G.	Prazak	dprazak@otpco.com	Otter Tail Power Company		P.O. Box 496 215 South Cascade Street Fergus Falls MN, 56538-0496 United States	Electronic Service		No	M-25-142

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
229	Matt	Privratsky	matt@nokomisenergy.com	Nokomis Energy		2639 Nicollet Ave Suite 200 Minneapolis MN, 55408 United States	Electronic Service		No	M-25-142
230	Elizabeth	Psihos	elizabeth.psihos@idealenergies.com			null null, null United States	Electronic Service		No	M-25-142
231	Bridget	Rathsack	bridget.rathsack@burnsvillemn.gov	City of Burnsville, MN		100 Civic Center Parkway Burnsville MN, 55337 United States	Electronic Service		No	M-25-142
232	Peter	Reese	preese@sundialsolarenergy.com	Sundial Energy, LLC		3363 Republic Ave Saint Louis Park MN, 55426 United States	Electronic Service		No	M-25-142
233	Generic Notice	Regulatory	regulatory_filing_coordinators@otpco.com	Otter Tail Power Company		215 S. Cascade Street Fergus Falls MN, 56537 United States	Electronic Service		No	M-25-142
234	John C.	Reinhardt		Laura A. Reinhardt		3552 26th Ave S Minneapolis MN, 55406 United States	Paper Service		No	M-25-142
235	Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	1400 BRM Tower 445 Minnesota St St. Paul MN, 55101-2131 United States	Electronic Service		Yes	M-25-142
236	Kevin	Reuther	kreuther@mncenter.org	MN Center for Environmental Advocacy		26 E Exchange St, Ste 206 St. Paul MN, 55101-1667 United States	Electronic Service		No	M-25-142
237	Micah	Revell	micah.revell@stinson.com	Stinson LLP		50 South Sixth St Ste 2600 Minneapolis MN, 55402 United States	Electronic Service		No	M-25-142
238	Michael	Riewer	mriewer@otpco.com	Otter Tail Power Company		PO Box 4496 Fergus Falls MN, 56538-0496 United States	Electronic Service		No	M-25-142
239	Jonathan	Roberts	jroberts@soltage.com	Soltage		66 York St 5th Floor Jersey City NJ, 07302 United States	Electronic Service		No	M-25-142
240	Noah	Roberts	nroberts@cleanpower.org	Energy Storage Association		1155 15th St NW, Ste 500 Washington DC, 20005 United States	Electronic Service		No	M-25-142
241	Kristi	Robinson	krobinson@star-energy.com	STAR Energy Services, LLC		1401 South Broadway Pelican Rapids MN, 56572 United States	Electronic Service		No	M-25-142
242	Daniel	Rogers	dan@nokomispartners.com			2639 Nicollet Ave Ste 200 Minneapolis MN, 55408 United States	Electronic Service		No	M-25-142

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
243	Michael	Ruiz	michael.ruiz@xcelenergy.com	Xcel Energy		null null, null United States	Electronic Service		No	M-25-142
244	Nathaniel	Runke	nrunke@local49.org			611 28th St. NW Rochester MN, 55901 United States	Electronic Service		No	M-25-142
245	Darla	Ruschen	d.ruschen@bcrea.coop	Brown County Rural Electrical Association		PO Box 529 24386 State Highway 4 Sleepy Eye MN, 56085 United States	Electronic Service		No	M-25-142
246	Delaney	Russell	delaney@mnipl.org	Just Solar Coalition		4407 E Lake Street Minneapolis MN, 55407 United States	Electronic Service		No	M-25-142
247	Kwadwo	Safo	ksafo@dakotaelectric.com	Dakota Electric Association		null null, null United States	Electronic Service		No	M-25-142
248	Robert K.	Sahr	bsahr@eastriver.coop	East River Electric Power Cooperative		P.O. Box 227 Madison SD, 57042 United States	Electronic Service		No	M-25-142
249	Ian	SantosMeeker	ians@ips-solar.com	IPS Solar		null null, null United States	Electronic Service		No	M-25-142
250	Joseph L	Sathe	jsathe@kennedy-graven.com	Kennedy & Graven, Chartered		150 S 5th St Ste 700 Minneapolis MN, 55402 United States	Electronic Service		No	M-25-142
251	Kenric	Scheevel	kjs@dairynet.com	Dairyland Power Cooperative		3200 East Ave S PO Box 817 La Crosse WI, 54602 United States	Electronic Service		No	M-25-142
252	Dean	Schiro	dean.e.schiro@xcelenergy.com	Xcel Energy		null null, null United States	Electronic Service		No	M-25-142
253	Jacob J.	Schlesinger	jschlesinger@keyesfox.com	Keyes & Fox LLP		1580 Lincoln St Ste 880 Denver CO, 80203 United States	Electronic Service		No	M-25-142
254	Jeff	Schoenecker	jschoenecker@dakotaelectric.com	Dakota Electric Association		4300 220th Street W Farmington MN, 55024 United States	Electronic Service		No	M-25-142
255	Peter	Scholtz	peter.scholtz@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	Suite 1400 445 Minnesota Street St. Paul MN, 55101-2131 United States	Electronic Service		No	M-25-142
256	Kay	Schraeder	kschraeder@minnkota.com	Minnkota Power		5301 32nd Ave S Grand Forks ND, 58201 United States	Electronic Service		No	M-25-142
257	Matthew	Schuerger	matthew.schuerger@state.mn.us		Public Utilities Commission	121 7th Place East Suite 350 St. Paul MN, 55101 United States	Electronic Service		No	M-25-142
258	Ronald J.	Schwartau	rschwartau@noblesce.com	Nobles Electric Cooperative		22636 U.S. Hwy. 59 Worthington MN, 56187 United States	Electronic Service		No	M-25-142

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
259	Rob	Scott Hovland	rob.scott-hovland@mrenergy.com	Missouri River Energy Services		3724 W Avera Dr PO Box 88920 Sioux Falls SD, 57109-8920 United States	Electronic Service		No	M-25-142
260	Emma	Searson	esearson@solarunitedneighbors.org	Solar United Neighbors		646 S Barrington Ave Apt 101 Los Angeles CA, 90049 United States	Electronic Service		No	M-25-142
261	Dean	Sedgwick	sedgwick@itascapower.com	Itasca Power Company		PO Box 455 Spring Lake MN, 56680 United States	Electronic Service		No	M-25-142
262	Maria	Seidler	maria.seidler@dom.com	Dominion Energy Technology		120 Tredegar Street Richmond VA, 23219 United States	Electronic Service		No	M-25-142
263	David	Shaffer	david.shaffer@novelenergy.biz	Novel Energy Solutions		2303 Wycliff St Ste 300 St. Paul MN, 55114 United States	Electronic Service		No	M-25-142
264	Patricia	Sharkey	psharkey@environmentallawcounsel.com	Midwest Cogeneration Association.		180 N LaSalle St Ste 3700 Chicago IL, 60601 United States	Electronic Service		No	M-25-142
265	Christopher L.	Sherman	csherman@sherman-associates.com	Solar Holdings LLC		233 Park Ave S Ste 201 Minneapolis MN, 55415 United States	Electronic Service		No	M-25-142
266	Doug	Shoemaker	dougs@charter.net	Minnesota Renewable Energy		2928 5th Ave S Minneapolis MN, 55408 United States	Electronic Service		No	M-25-142
267	Felicia	Skaggs	fskaggs@meeker.coop	Meeker Cooperative Light & Power		1725 US Highway 12 E Suite 100 Litchfield MN, 55355 United States	Electronic Service		No	M-25-142
268	Glen	Skarbakka	glen@s-pllc.com	Skarbakka PLLC		5411 Bartlett Blvd Mound MN, 55364 United States	Electronic Service		No	M-25-142
269	Anne	Smart	anne.smart@chargepoint.com	ChargePoint, Inc.		254 E Hacienda Ave Campbell CA, 95008 United States	Electronic Service		No	M-25-142
270	Joshua	Smith	joshua.smith@sierraclub.org			85 Second St FL 2 San Francisco CA, 94105 United States	Electronic Service		No	M-25-142
271	Ken	Smith	ken.smith@districtenergy.com	District Energy St. Paul Inc.		76 W Kellogg Blvd St. Paul MN, 55102 United States	Electronic Service		No	M-25-142
272	Trevor	Smith	trevor.smith@avantenergy.com	Avant Energy, Inc.		220 South Sixth Street Suite 1300 Minneapolis MN, 55402 United States	Electronic Service		No	M-25-142

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
273	Rafi	Sohail	rafi.sohail@centerpointenergy.com	CenterPoint Energy		800 LaSalle Avenue P.O. Box 59038 Minneapolis MN, 55459-0038 United States	Electronic Service		No	M-25-142
274	Beth	Soholt	bsoholt@cleangridalliance.org	Clean Grid Alliance		570 Asbury Street Suite 201 St. Paul MN, 55104 United States	Electronic Service		No	M-25-142
275	Marcia	Solie	m.solie@bcrea.coop	Brown County Rural Electrical Association		24386 State Hwy. 4, PO Box 529 Sleepy Eye MN, 56085 United States	Electronic Service		No	M-25-142
276	Braden	Solum	braden.solum@idealenergies.com	iDEAL Energies		5810 Nicollet Ave Minneapolis MN, 55419 United States	Electronic Service		No	M-25-142
277	Karl	Sonneman	karl17@hbci.com	Law Office of Karl W. Sonneman		111 Riverfront Suite 202 Winona MN, 55987 United States	Electronic Service		No	M-25-142
278	Brandon	Stamp	brandon.j.stamp@xcelenergy.com	Xcel Energy		401 Nicollet Mall Minneapolis MN, 55401 United States	Electronic Service		No	M-25-142
279	Sky	Stanfield	stanfield@smwlaw.com	Shute, Mihaly & Weinberger		396 Hayes Street San Francisco CA, 94102 United States	Electronic Service		No	M-25-142
280	Russ	Stark	russ.stark@ci.stpaul.mn.us	City of St. Paul		Mayor's Office 15 W. Kellogg Blvd., Suite 390 Saint Paul MN, 55102 United States	Electronic Service		No	M-25-142
281	Byron E.	Starns	byron.starns@stinson.com	STINSON LLP		50 S 6th St Ste 2600 Minneapolis MN, 55402 United States	Electronic Service		No	M-25-142
282	Kristin	Stastny	kstastny@taftlaw.com	Taft Stettinius & Hollister LLP		2200 IDS Center 80 South 8th Street Minneapolis MN, 55402 United States	Electronic Service		No	M-25-142
283	Lindsey	Stegall	lindsey.stegall@evgo.com	EVgo Services, LLC		11835 W Olympic Blvd Ste 900E Los Angeles CA, 90064 United States	Electronic Service		No	M-25-142
284	Cary	Stephenson	cstephenson@otpco.com	Otter Tail Power Company		215 South Cascade Street Fergus Falls MN, 56537 United States	Electronic Service		No	M-25-142
285	Chad	Stevenson	chad.stevenson@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	445 Minnesota St. Suite 1400 St. Paul MN, 55101 United States	Electronic Service		No	M-25-142

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
286	Tammy	Sundbom	tsundbom@mnpower.com	Minnesota Power		null null, null United States	Electronic Service		No	M-25-142
287	Sherry	Swanson	sswanson@noblesce.com	Nobles Cooperative Electric		22636 US Highway 59 PO Box 788 Worthington MN, 56187 United States	Electronic Service		No	M-25-142
288	Boratha	Tan	btan@votesolar.org	Vote Solar		null null, null United States	Electronic Service		No	M-25-142
289	Bryant	Tauer	btauer@whe.org	Wright-Hennepin		6800 Electric Dr Rockford MN, 55373 United States	Electronic Service		No	M-25-142
290	Dean	Taylor	dtaylor@pluginamerica.org	Plug In America		6380 Wilshire Blvd, Suite 1000 Los Angeles CA, 90048 United States	Electronic Service		No	M-25-142
291	Whitney	Terrill	whitney@mnipl.org	Minnesota Interfaith Power & Light		null null, null United States	Electronic Service		No	M-25-142
292	Daniel	Tikk	daniel.tikk@state.mn.us		Department of Commerce	85 7th Place East Suite 280 Saint Paul MN, 55101 United States	Electronic Service		No	M-25-142
293	Kate	Tohme	ktohme@newleafenergy.com	New Leaf Energy		null null, null United States	Electronic Service		No	M-25-142
294	Stuart	Tommerdahl	stommerdahl@otpco.com	Otter Tail Power Company		215 S Cascade St PO Box 496 Fergus Falls MN, 56537 United States	Electronic Service		No	M-25-142
295	Taige	Tople	taige.d.tople@xcelenergy.com	Northern States Power Company dba Xcel Energy-Elec		414 Nicollet Mall 401 7th Floor Minneapolis MN, 55401 United States	Electronic Service		No	M-25-142
296	Jason	Topp	jason.topp@lumen.com	Qwest Communications Company, LLC.		200 S 5th St Ste 2200 Minneapolis MN, 55402 United States	Electronic Service		No	M-25-142
297	Emma Marshall	Torres	emarshall-torres@convergentep.com			null null, null United States	Electronic Service		No	M-25-142
298	Zack	Townsend	zachary.townsend@brookfieldrenewable.com	Brookfield Renewable		200 Liberty St FL 14 New York NY, 10281 United States	Electronic Service		No	M-25-142
299	Pat	Treseler	pat.jcplaw@comcast.net	Paulson Law Office LTD		4445 W 77th Street Suite 224 Edina MN, 55435 United States	Electronic Service		No	M-25-142
300	Jeff	Triplett	triplettj@powersystem.org	MREA		10710 Town Square Dr NW St 201 Minneapolis MN, 55449 United States	Electronic Service		No	M-25-142
301	Adam	Tromblay	atromblay@noblesce.com	Nobles Cooperative Electric		P.O. Box 58 Slayton MN, 56127-0058 United States	Electronic Service		No	M-25-142

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302	Lise	Trudeau	lise.trudeau@state.mn.us		Department of Commerce	85 7th Place East Suite 500 Saint Paul MN, 55101 United States	Electronic Service		No	M-25-142
303	Alan	Urban	alan.m.urban@xcelenergy.com	Xcel Energy		null null, null United States	Electronic Service		No	M-25-142
304	Matt	Van Arkel	mvanarkel@newleafenergy.com			55 Technology Drive Suite 102 Lowell MA, 01851 United States	Electronic Service		No	M-25-142
305	Gary	Van Winkle	gvanwinkle@mylegalaid.org	Mid-Minnesota Legal Aid		111 N Fifth St Ste 100 Minneapolis MN, 55403 United States	Electronic Service		No	M-25-142
306	John	Vaughn	nik@rreal.org	Rural Renewable Energy Alliance		3963 8th Street SW Backus MN, 55435 United States	Electronic Service		No	M-25-142
307	Ellen	Veazey	lveazey@solarunitedneighbors.org	Solar United Neighbors		1350 Connecticut Ave NW Ste 412 Washington DC, 20036 United States	Electronic Service		No	M-25-142
308	Sam	Villella	sdvillella@gmail.com			10534 Alamo Street NE Blaine MN, 55449 United States	Electronic Service		No	M-25-142
309	Curt	Volkmann	curt@newenergy-advisors.com	Fresh Energy		408 St Peter St Saint Paul MN, 55102 United States	Electronic Service		No	M-25-142
310	Wendy	Vorasane	wendy.vorasane@idealenergies.com			null null, null United States	Electronic Service		No	M-25-142
311	Robert J.V.	Vose	rvose@kennedy-graven.com	Kennedy & Graven, Chartered		150 S 5th St Ste 700 Minneapolis MN, 55402 United States	Electronic Service		No	M-25-142
312	Stacy	Wahlund	swahlund@otpco.com	Otter Tail Power Company		215 S. Cascade St Fergus Falls MN, 56537 United States	Electronic Service		No	M-25-142
313	Sarah	Walinga	swalinga@solarcity.com	Energy Freedom Coalition		3055 Clearview Way San Mateo MN, 94402 United States	Electronic Service		No	M-25-142
314	Kevin	Walker	kwalker@beaconinterfaith.org	Beacon Interfaith Housing Collaborative		null null, null United States	Electronic Service		No	M-25-142
315	Roger	Warehime	roger.warehime@owatonnautilities.com	Owatonna Municipal Public Utilities - Gas		208 S Walnut Ave PO BOX 800 Owatonna MN, 55060 United States	Electronic Service		No	M-25-142
316	Jenna	Warmuth	jwarmuth@mnpower.com	Minnesota Power		30 W Superior St Duluth MN, 55802-2093 United States	Electronic Service		No	M-25-142

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
317	Samantha	Weaver	samantha@communitysolaraccess.org	Coalition for Community Solar Access		1380 Monroe St. Washington DC DC, 20010 United States	Electronic Service		No	M-25-142
318	Elizabeth	Wefel	eawefel@flaherty-hood.com	Missouri River Energy Services		525 Park St Ste 470 Saint Paul MN, 55103 United States	Electronic Service		No	M-25-142
319	Sarah	Whebbe	swhebbe@mnseia.org	MnSEIA		445 Minnesota Street Suite 730 St. Paul MN, 55101 United States	Electronic Service		No	M-25-142
320	Joshua	Williams	joshua@highlandfleets.com	Highland Electric Fleets		200 Cummings Center Suite 273-D Beverly MA, 01915 United States	Electronic Service		No	M-25-142
321	Laurie	Williams	laurie.williams@sierraclub.org	Sierra Club		Environmental Law Program 1536 Wynkoop St Ste 200 Denver CO, 80202 United States	Electronic Service		No	M-25-142
322	John	Williamson	john.williamson@state.mn.us	Minnesota Department of Labor and Industry		443 Lafayette Rd N St. Paul MN, 55155-4341 United States	Electronic Service		No	M-25-142
323	Anthony	Willingham	anthony.willingham@electrifyamerica.com	Electrify America		1950 Opportunity Way Suite 1500 Reston VA, 20190 United States	Electronic Service		No	M-25-142
324	Danielle	Winner	danielle.winner@state.mn.us		Department of Commerce	85 7th Place East Suite 500 Saint Paul MN, 55101 United States	Electronic Service		No	M-25-142
325	Heidi	Winter	hwinter@co.murray.mn.us	Murray County		2500 28th Street PO Box 57 Slayton MN, 56172 United States	Electronic Service		No	M-25-142
326	Robyn	Woeste	robynwoeste@alliantenergy.com	Interstate Power and Light Company		200 First St SE Cedar Rapids IA, 52401 United States	Electronic Service		No	M-25-142
327	Terry	Wolf	terry.wolf@mrenergy.com	Missouri River Energy Services		3724 W Avera Dr PO Box Sioux Falls SD, 57109-8920 United States	Electronic Service		No	M-25-142
328	Curtis	Zaun	curtis@cpzlaw.com			3254 Rice Street Little Canada MN, 55126 United States	Electronic Service		No	M-25-142
329	Brian	Zavesky	brianz@mrenergy.com	Missouri River Energy Services		3724 West Avera Drive P.O. Box 88920 Sioux Falls SD, 57108-	Electronic Service		No	M-25-142

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
						8920 United States				
330	Christopher	Zibart	czibart@atcllc.com	American Transmission Company LLC		W234 N2000 Ridgeview Pkwy Court Waukesha WI, 53188-1022 United States	Electronic Service		No	M-25-142
331	Kurt	Zimmerman	kwz@ibew160.org	Local Union #160, IBEW		2909 Anthony Ln St Anthony Village MN, 55418-3238 United States	Electronic Service		No	M-25-142
332	Emily	Ziring	eziring@stlouispark.org	City of St. Louis Park		5005 Minnetonka Blvd St. Louis Park MN, 55416 United States	Electronic Service		No	M-25-142
333	Ari	Zwick	ari.zwick@state.mn.us		Department of Commerce	85 7th Place East Suite 280 Saint Paul MN, 55101 United States	Electronic Service		No	M-25-142