STATE OF MINNESOTA
BEFORE THE PUBLIC UTILITIES COMMISSION

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In the Matter of Xcel Energy's 2025 Integrated Distribution Plan	MPUC DOCKET NO. E-002/M-25-142

INITIAL COMMENTS ON XCEL'S INTEGRATED DISTRIBUTION PLAN OF ENVIRONMENTAL LAW & POLICY CENTER, COOPERATIVE ENERGY FUTURES, AND VOTE SOLAR

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I. INTRODUCTION

In its 2025 Integrated Distribution Plan (IDP), Northern States Power Company, doing business as Xcel Energy ("Xcel" or "the Company") proposes substantial increases in distribution spending. For the 2025-2030 period, Xcel plans to make capital investments totaling over $5 billion, spending nearly $900 million per year on average.[1] In the prior five-year period, Xcel spent less than half of that—about $2 billion on capital investments, or about $436 million per year on average.[2] The top drivers of this increased spending are asset health and reliability, capacity expansion, and the Company's new wildfire mitigation program.[3] Distribution spending is necessary to ensure system safety and reliability and meet state policy goals, including those related to carbon-free energy, distributed energy resources (DERs), and electrification. At the same time, the continued growth in distribution budgets also raises major affordability concerns, especially at a time when many customers already face affordability challenges.

In these comments, Environmental Law & Policy Center, Cooperative Energy Futures, and Vote Solar (together, ELPC/CEF/VS) emphasize this overarching need to ensure Xcel demonstrates in this IDP that its distribution investments are necessary and cost-effective. We recommend ways that the Company can most cost-effectively integrate and leverage DERs, which can serve as relatively low-cost distribution solutions to help avoid or defer larger, traditional distribution investments. Although Xcel recognizes some of this potential in this IDP, its progress towards realizing these cost savings has been limited. ELPC/CEF/VS provide recommendations to move more quickly to realize the potential benefits of DERs. In addition, we highlight the need to integrate equity considerations into the Company's planning and

[1] Xcel Energy, Integrated Distribution Plan: 2026-2035, at Ch. 6, p. 12 (and related workpapers) (Oct. 31, 2025) ("2025 Xcel IDP").
[2] 2025 Xcel IDP at Ch 6, p. 9.
[3] *Id.* at Ch. 6, p. 12.

investments, to ensure that the benefits of Xcel's planned investments, such as improvements to reliability, are equitably experienced across its system.

Our engagement in this 2025 IDP continues our similar advocacy in prior Xcel IDPs, rate cases, Safety Reliability, and Service Quality (SRSQ) proceedings, and other related dockets. Specifically, in its Order in Xcel's last IDP proceeding, the Commission largely adopted our recommendations related to the Company's plans for Flexible Interconnection (FI) and Distributed Energy Resources Management System (DERMS).[4] The Commission also required the Company to further explore and consider implementation of our recommendations related to its Planned Net Load (PNL) methodology.[5] In these comments, we review Xcel's compliance with these Order points and suggest additional Commission action where Xcel has fallen short of meeting them.

II. COMMENT OVERVIEW

When the Commission established the Integrated Distribution Plan filing requirements for Xcel Energy, it identified the following five filing requirements:

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] Docket No. E-002/M-23-452, *In the Matter of Xcel Energy's 2023 Integrated Distribution Plan*, Order Accepting 2023 Integrated Distribution Plan and modifying Reporting Requirements, at 16-18, 26-27, ¶¶ 19-23 (Sept. 16, 2024) ("2023 Xcel IDP Order"). In the last IDP, ELPC/CEF/VS commented with Sierra Club as "Grid Equity Commenters."
[5] *Id.* at 14-16, 26, ¶ 17.

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 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.[6]

ELPC/CEF/VS commend the Commission on its ongoing efforts to promote these goals through the Company's IDPs. We highlight goals 2 and 3 above, which together speak to the ongoing importance of improving access to DERs, particularly through customer ownership. In addition, we underscore the need for optimized utilization of these DERs as system resources, consistent with goal 4. With growing distribution costs and ongoing affordability concerns for the Company's customers, it is even more critical that the Company minimize total system costs. ELPC/CEF/VS recognize that Xcel must make investments to enable DERs on its system and to realize the equitable clean energy future Minnesota envisions. In these comments, we emphasize the need both to ensure these investments are cost-effective and to optimize use of DERs to defer or avoid investments.

In this IDP, Xcel predicts significant DER growth in the coming years. For example, by 2030, Xcel predicts 2,180 MW of distributed solar PV under its most conservative base case, an over 80% increase from 1,189 MW in 2025.[7] Under the same base case, the Company predicts a further increase to 2,582 MW by 2035.[8] These forecasts, along with Xcel's Expanded Non-Residential and High forecasts, are shown in IDP Figure 4 below.[9]

[6] Docket No. E-002/CI-18-251, *In the Matter of Distribution System Planning for Xcel Energy*, Order Approving Integrated Distribution Planning Filing Requirements for Xcel Energy, at 5 ¶ 1, Att. at 1 (Aug. 30, 2018).
[7] 2025 Xcel IDP at Ch. 1, pp. 41-42.
[8] *Id.*
[9] *Id.* at Overview, p. 6.

Figure 4
State of Minnesota Distributed Solar Photovoltaic Forecast (MWac)

Likewise, Xcel predicts steep growth in distributed energy storage, from 668 kW (0.668 MW) in 2026 to 1,171 kW (1.171 MW) in 2030 to 2,347 kW (2.347 MW) in 2035.[10] ELPC/CEF/VS encourage the Company and the Commission to view this and other DER growth as an opportunity to leverage these resources as cost-effective solutions to the Company's distribution and capacity needs, and ones that can often be deployed more quickly than traditional infrastructure.

Xcel recognizes the potential benefits of DERs on its system, including to: reduce peak power requirements; serve as emergency power sources; manage local capacity constraints; reduce system power requirements; and serve as a source of carbon-free energy.[11] The Company states: "We will continue evaluating these benefits through our NWA analysis and work to

[10] *Id.* at Ch. 1, p. 44.
[11] *Id.* at Ch. 7, pp 27-28.

incorporate DER impacts into distribution planning. As DER costs decline and software platforms mature, we expect opportunities in this area to expand."[12] Despite the Company's forward-looking intent to incorporate DERs into its distribution planning, Xcel appears to maintain a focus on the potential negative impacts of DERs, spending five pages describing these negative impacts in detail, as compared to the two-page high-level discussion of the potential benefits of DERs.[13] ELPC/CEF/VS agree that DERs, like any grid resource, can create challenges or require upgrades. However, the Company can avoid or significantly reduce many of these issues through proactive strategies that enable DERs to deliver their full value, such as adopting Flexible Interconnection. Xcel appears to recognize this later in the IDP, where it states: "One potential application of DERMS is enabling flexible interconnection agreements, which could reduce the need for or cost of system upgrades—provided the approach is scalable and performs as expected."[14] However, as discussed further below, the Company has made very limited progress towards such Flexible Interconnection arrangements and has neglected to explore nearer-term approaches like static Flexible Interconnection that do not require DERMS. Similarly, Xcel's proposed Distributed Capacity Procurement (DCP) program, Capacity*Connect (C*C), could better leverage the distribution benefits of DERs in the near-term if modified in the ways we have suggested, which we also discuss further below.

The Company's apparent focus on the *future* possibilities of DERs rather than their ability to beneficially impact distribution planning *today* is reflected in Xcel's limited integration of DERs into its planning process to date, primarily via the Company's Non-Wires Alternatives process. For example, the Company states in the IDP: "… we are currently unable to report

[12] 2025 Xcel IDP at Ch. 7, p. 28.
[13] *Id.* at Ch. 7, pp 27-32.
[14] *Id.* at Ch. 10, p. 8.

distribution system locations for energy efficiency and demand response (DR) programs due to the nature of our DSM offerings … Additionally, our DSM program systems are separate from those used for distribution system planning and operations."[15] In response to Information Request No. 19 from Fresh Energy (Attachment 1) on whether Xcel's Aggregator DERMS will address this challenge, Xcel made a similar statement, indicating that it has not explored any integration of Aggregator DERMS with energy efficiency reporting systems or distribution system planning tools, and that its demand-side management programs operate separately from distribution planning tools. The Company's response makes clear that it treats demand response separately from distribution planning, with no impact from its Aggregator DERMS on its planning processes. While ELPC/CEF/VS support Xcel's future intent to leverage DERs in distribution planning, we encourage the Commission and the Company to act now to do so. Our recommendations in these comments identify concrete ways to achieve this goal using capabilities Xcel currently has or will have soon.

Furthermore, achieving the Commission's IDP goals in a cost-effective way, particularly those related to DER adoption, will require deliberate integration of the various complementary processes and programs that the Commission has required the Company to pursue within and alongside the IDP. These include: modifications to the Company's Planned Net Load (PNL) methodology; Flexible Interconnection; proactive distribution upgrades; reactive cost-sharing for upgrades; and the Company's proposed Capacity*Connect program. As discussed further in the subsections below and throughout these comments, ELPC/CEF/VS urge the Commission to ensure that the Company integrates these various efforts to advance DERs in an equitable, cost-effective manner.

[15] *Id.* at Ch. 7, p. 19.

A. Integration of Flexible Interconnection, Proactive Upgrades, and Reactive Cost-Sharing

ELPC/CEF/VS's recommendations in this docket build upon several prior Commission order points and subsequent stakeholder proceedings. In its September 16, 2024 Order in Xcel's last IDP proceeding (Docket No. E-002/M-23-452), the Commission established a work group "to develop a framework on cost allocation and proactive upgrades for Xcel."[16] Shortly afterwards, responding to a separate legislative directive, the Commission also established a companion reactive workgroup "to develop standards for distribution system cost sharing for interconnection in constrained areas."[17] In addition, in its 2024 Order, Commission included several order points related to Flexible Interconnection:

> 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.

[16] 2023 Xcel IDP Order at 25, ¶ 14.

Minn. Stat. § 216B.2425, subd.9 requires Xcel to include in its IDP, beginning in 2023: "(1) a forecast of distribution system upgrades necessary to accommodate the interconnection of distributed generation resulting from the utility's compliance with sections 216B.1641 and 216B.1691, subdivision 2h, and other customer-sited projects, including energy storage systems; (2) an evaluation of measures that can reduce the need for or cost of distribution system upgrades to enable the interconnection of distributed generation resources, including but not limited to the employment of smart inverters, grid management tools, distributed energy resources management tools, and energy export tariffs; and (3) a discussion of alternative methods to allocate costs of distribution system upgrades among distributed generation owners or developers and ratepayers."

[17] Docket No. CI-24-288, *In the Matter of Establishing Tariffs for Distribution System Cost Sharing for Interconnection in Constrained Areas*, Notice Soliciting Stakeholder Members (Sept. 26, 2024) (referencing Minnesota Session Laws – 2024, Regular Session, Chapter 126, Article 6, Section 53, which required that, by September 1, 2024: "the commission must initiate a proceeding to establish by order generic standards for the sharing of utility costs necessary to upgrade a utility's distribution system by increasing hosting capacity or applying other necessary distribution system upgrades at a congested or constrained location in order to allow for the interconnection of distributed generation facilities at the congested or constrained location and to advance the achievement of the state's renewable and carbon-free energy goals in Minnesota Statutes, section 216B.1691 and greenhouse gas emissions reduction goals in Minnesota Statutes, section 216H.02." It contains further specific directives related to this process.).

20. Xcel shall be transparent about the conditions under which the Company will use Flexible Interconnection, particularly with impacted DER owner/operators.

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.

Notably, Flexible Interconnection is a primary use case for DERMS, for which the Commission also directed Xcel to develop a detailed roadmap and conduct related stakeholder engagement.[18]

Since this time, these efforts have moved forward, albeit at different paces and to different degrees. The proactive work group developed the Proactive Distribution Grid Upgrade Framework, which the Commission approved in a September 2, 2025 Order in Docket No. E-002/CI-24-318. Xcel filed its first Proactive Upgrade Proposal (PUP) under this Framework with this 2025 IDP, which we have addressed in separate comments in this docket. The reactive work group also developed standards for the Distribution System Reactive Upgrades Process (DSRUP), which the Commission is scheduled to consider at its meeting on February 26, 2026, concurrent with the filing deadline for these comments.[19] And the Distributed Generation Workgroup (DGWG) has very recently begun to discuss Flexible Interconnection with an "education session" held on February 18, 2026.[20] Xcel also briefly addressed its plans for Flexible Interconnection in this IDP, focused on dynamic Flexible Interconnection using DERMS.[21]

[18] 2023 Xcel IDP Order at 26-27, ¶¶ 22-23.
[19] Docket No. E002, E015, E017/CI-24-288*, In the Matter of Establishing Tariffs for Distribution System Costs Sharing for Interconnection in Constrained Areas*, Briefing Papers (Feb. 13, 2026).
[20] Docket No. E999/CI-16-521, *In the Matter of Updating the Generic Standards for the Interconnection and Operation of Distributed Generation Facilities Established under Minn. Stat. §216B.1611*, Notice of DGWG Education Session (Feb. 17, 2026).
[21] 2025 Xcel IDP at Ch. 7, pp. 3-6.

ELPC, Cooperative Energy Futures, and Vote Solar have each participated in these various efforts and plan to continue to do so. Although we have ongoing concerns about Xcel's slow progress on Flexible Interconnection, as discussed in Section III.B.15 below, we also recognize and appreciate the progress made to date on proactive upgrades and reactive cost-sharing. ELPC/CEF/VS suggest that this IDP and the next phases of the various work groups present opportunities to ensure these approaches are working together to promote the most cost-effective solutions to distribution planning and DER integration.

For example, the proactive work group has identified Flexible Interconnection as a key topic for its Phase 2 process. In recent discussions in that work group, we have emphasized that Flexible Interconnection, proactive upgrades, and reactive cost-sharing are inherently intertwined, achieving related benefits with different risk profiles, as summarized in the table below.

	Flexible Interconnection	**Proactive Upgrades**	**Reactive Cost-Sharing**
Increase Adoption Speed	+	+	
Avoid Interconnection Costs	+		
Provide Pathway to Upgrades		+	+
Provide More Predictable Interconnection Costs		+	+
Ratepayer Cost Risk (relative)		higher	lower
Interconnection Applicant Operational Risk	varies		

We suggest that combining an effective Flexible Interconnection program with the reactive cost-sharing process (DSRUP) could create a fast, low-risk path for new interconnections and system expansion. This combination could offer a relatively lower-risk alternative to proactive upgrades,

at least in some cases. Applicants can use Flexible Interconnection to avoid an expensive upgrade until sufficient interest triggers DSRUP, at which point several applicants can share the cost for a necessary upgrade. This combination approach could speed interconnection in congested areas and then provide a pathway to relief from curtailment via a reactive upgrade whose cost is mostly, if not entirely, shared among applicants. And it could reduce ratepayer costs and risks that may have come from a proactive upgrade based on a less-certain forecast for a need that may not fully materialize. However, ELPC/CEF/VS continue to view proactive upgrades as an important complementary mechanism, especially in the nearer term as Flexible Interconnection and DSRUP are implemented and refined.

While the work groups continue to consider these issues, ELPC/CEF/VS emphasize that, regardless of the outcome of these conversations, intentional integration of these processes is essential to ensuring they effectively complement and support the Company's distribution planning and IDP. And functional Flexible Interconnection is a linchpin to such integration. As we discuss further below in Section III.B.15, we urge the Commission to require Xcel both to adopt static Flexible Interconnection as a near-term approach (again) and to develop the details of its dynamic Flexible Interconnection in a timely and transparent manner.

B. Relationship to Capacity*Connect

In its IDP, Xcel describes its Capacity*Connect program as "an effort to begin to better understand this dynamic [i.e., the positive and negative impacts of DERs, particularly battery storage, on its system]. Capacity*Connect would deploy Company-owned and -operated battery energy storage systems (BESS) of 1-3 MW each, sited strategically at customer site host locations and connected front-of-the-meter to the Company's distribution system to serve primarily as a bulk system asset. By strategically siting these assets on the distribution system, we seek to realize coincident distribution system benefits even as the BESS are operated for bulk

system energy and capacity use cases."[22] As we[23] and other stakeholders have emphasized in the Capacity*Connect case (Docket No. E002/M-25-378), by prioritizing bulk-system value and only realizing coincident distribution system benefits, Xcel is missing a critical opportunity to begin to leverage DERs as cost-effective distribution system resources. If Xcel prioritizes their distribution system value, DERs have the potential to allow the Company to use its system more efficiently and reduce the Company's distribution costs. Together with the Department of Commerce and several other stakeholders in Docket No. 25-378, we have recommended that the Commission require Xcel to prioritize distribution objectives in siting C*C resources and use the C*C program to test and learn how to realize distribution value through DER. ELPC/CEF/VS suggest that the Company's identification of distribution constraints and needs in its IDP should inform siting of C*C resource where they can meet these needs and provide value to the Company and its customers.

In addition to prioritizing distribution value in Capacity*Connect, we and other stakeholders have also recommended that the Commission require Xcel to develop and file a separate Distributed Power Plant (DPP)[24] program. Such a program would leverage behind-the-meter (BTM), customer- and third-party-owned resources in a similar way to Capacity*Connect, whose resources would be front-of-the-meter and utility-owned, at least initially. Specifically, these resources would include distributed energy storage, which Xcel forecasts to grow from 668 kW in 2026 to 1.17 MW in 2030 and 2.35 MW in 2035, as noted above.[25] These forecasts do not include Capacity*Connect resources. To the extent Xcel or the Commission promotes BTM

[22] 2025 Xcel IDP at Ch. 7, p. 34.
[23] ELPC, Cooperative Energy Futures, and Vote Solar commented in Docket No. 25-378 together with Institute for Local Self-Reliance (ILSR) and Solar United Neighbors (SUN).
[24] Distributed Power Plant (DPP) and Virtual Power Plant (VPP) are interchangeable terms. We used DPP in our Capacity*Connect comments and therefore use it here, although we have used VPP in other proceedings. In all cases, we refer to the same concept.
[25] 2025 Xcel IDP at Ch. 1, p. 44.

energy storage through other programs or efforts, doing so would only further grow the pool of distributed batteries that a DPP could leverage. In any case, although BTM resources primarily serve customer needs and help reduce their bills, the Company could also rely on them in identified circumstances to realize system values, including bulk power/capacity and distribution values. Since a BTM DPP program would leverage customer and third-party investments, it could provide a particularly cost-effective solution. Although such a complementary DPP program would most likely primarily address bulk-system/capacity needs, it could also help reduce distribution system costs and the IDP could also help to inform which BTM customer resource to target for program participation. We note that Xcel's Colorado company has already launched its Renewable Battery Connect program, a DPP program.[26] We are hopeful the Company can apply this Colorado experience to Minnesota.

With its Capacity*Connect proposal, Xcel also proposed a "Limited Grid DERMS," along with the same or very similar DERMS Roadmap filed in this IDP proceeding. In the Capacity*Connect proceeding, we emphasized the need to ensure that Xcel uses any Limited Grid DERMS to dispatch C*C resources in response to identified distribution needs, and that the Company documents and reports when and how DERMS dispatch decisions reflect trade-offs between bulk-system and distribution needs. We recommend that any learnings from the Company's Limited Grid DERMS inform future DERMS investments and deployment, including through its Integrated Distribution Plan. We discuss Xcel's DERMS Roadmap and related proposals below in Section III.16.h.

[26] *Id.* at Ch. 7, p. 34.

C. Integration of Equity Considerations into Distribution Planning and Investments

Over the past several years, versions of our coalition have argued for incorporating equity considerations into Xcel's distribution planning, budgeting, and investments, in the Company's IDP dockets and other proceedings, including rate cases and Safety, Reliability, and Service Quality (SRSQ) dockets.[27] As part of this advocacy, we introduced a study from Drs. Gabriel Chan and Bhavin Pradhan, which demonstrated racial disparities in reliability (CELI-12) as well as disconnections.[28] Xcel had similar results from its own study, conducted by TRC.[29] Since then, Xcel has proposed a targeted undergrounding program, intended in part to address these identified disparities,[30] and now further developed in this IDP. We discuss Xcel's targeted undergrounding proposal further below in Section III.B.16.e. In its January 13, 2025 Order in Xcel's last SRSQ proceeding (Docket No. 24-27), the Commission also directed the utility to repeat a similar disparity study every three years, with the next study expected with Xcel's April 1, 2027 SRSQ report.[31] In addition, the Commission directed Xcel to "hire an independent third-

[27] These proceedings include: E002/M-25-27; E-002/GR-24-320; E002/M-24-27; E002/CI-23-452; E002/M-22-633; E002/M-21-694; E002/GR-21-630; E002/M-20-406; E002/M-20-374; E002/M-19-666; and E002/CI-17-401. In these dockets, our coalition has included various combinations of: ELPC; Vote Solar; Cooperative Energy Futures; Sierra Club; Minnesota Interfaith Power & Light; and Community Power.

[28] Docket No. E002/M-24-27, *In the Matter of Northern States Power Company d/b/a Xcel Energy's 2023 Annual Safety, Reliability, and Service Quality Report*, Initial Comments of Grid Equity Commenters: Cooperative Energy Futures, Environmental Law & Policy Center, Sierra Club, and Vote Solar (Aug. 27, 2024); Docket No. E-002/M-23-452, *In the Matter of Xcel Energy's 2023 Integrated Distribution Plan*, Initial Comments of Grid Equity Commenters: Cooperative Energy Futures, Environmental Law & Policy Center, Sierra Club, and Vote Solar (Mar. 1, 2024).

[29] Docket No. E002/M-24-27, *In the Matter of Northern States Power Company d/b/a Xcel Energy's 2023 Annual Safety, Reliability, and Service Quality Report*, Annual Report and Petition, Report Ch. VI & Att. Q (Apr. 1, 2024) ("24-27 Xcel SRSQ Report"); *see also* 2025 Xcel IDP at Ch. 7, p. 45 (discussing the TRC study).

[30] E-002/M-25-27, *In the Matter of Xcel Energy's 2024 Annual Safety, Reliability and Service Quality Report,* Annual Report at 125 (Apr. 1, 2025); 24-27 Xcel SRSQ Report at 111; *see also* Docket No. E-002/GR-24-320, *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesot*a, Initial Brief of Northern States Power Company d/b/a Xcel Energy, at 213-16 (Jan. 28, 2026) (describing Xcel's pending request for targeted undergrounding cost recovery for 2025-26).

[31] Docket No. E002/M-24-27, *In the Matter of Northern States Power Company d/b/a Xcel Energy's 2023 Annual Safety, Reliability, and Service Quality Report*, Order Accepting Reports and Setting Additional Requirements, at 14, ¶ 43 (Jan. 13, 2025) ("24-27 Xcel SRSQ Order").

party evaluator with expertise in evaluating racial disparities to conduct a one-year study that will evaluate Xcel's practices and policies related to capital investment planning, outage restoration practices, and shutoff practices to better understand the causes of these discrepancies in shutoff rates and service reliability."[32]

Looking ahead, ELPC/CEF/VS continue to emphasize the need to integrate equity considerations transparently in the Integrated Distribution Plan, and in the Company's investment prioritization and ultimate cost recovery proposals in its rate cases, to avoid perpetuation of existing disparities or introduction of any additional disparities. We find this even more important today in light of ongoing affordability challenges, which are likely to impact low-income and BIPOC customers disproportionately. In addition to ensuring the Company's distribution investments and planning are as cost-effective as possible, it is critical to ensure that customers benefit equitably from system services, including through improved reliability, resiliency, and access to DERs and their benefits. Advancing equity may mean investing more in communities that have historically faced and continue to face inequitable negative impacts in utility service and DER access. While ELPC/CEF/VS recognize that the Company is in the process of studying its capital investment planning and other processes to better understand the previously identified disparities, its third-party study does not preclude the Commission taking action in this IDP to direct Xcel to integrate equity considerations transparently into the Company's distribution planning and budgeting going forward. Once Xcel has completed the study, the Company should explain how it will use its results to further improve its integration of equity considerations into its planning and investment processes. We discuss this issue further and provide specific recommendations in Section III.B.17 below.

[32] *Id.* at 15, ¶ 46.

III. RESPONSES TO TOPICS OPEN FOR COMMENT AND RECOMMENDATIONS

In the following subsections, ELPC/CEF/VS respond to the Commission's identified topics open for comment in its November 13, 2025 Notice of Comment Period, using the same numbering as that Notice for ease of reference.

A. Xcel Energy 2025 Certification Request: Mobile Battery System

11. Should the Commission approve, modify, or deny certification of the mobile battery system?

ELPC/CEF/VS take no position in these initial comments on whether the Commission should approve, modify, or deny certification of Xcel's proposed mobile battery system. However, consistent with the discussion above in Section II, we underscore the importance of coordinating such mobile battery system, if approved, with the Company's other initiatives to support DER growth and system reliability, including traditional investments, Flexible Interconnection, proactive upgrades, and other efforts. We would appreciate any additional information the Company could provide in reply comments related to the integration of the mobile battery system with its various distribution planning and DER integration initiatives.

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.

ELPC/CEF/VS have no comment at this time but may comment further in reply.

13. Are there any other issues or concerns related to this matter?

ELPC/CEF/VS have no comment at this time but may comment further in reply.

B. Xcel Energy 2025 Integrated Distribution Plan (IDP)

14. Should the Commission accept or reject Xcel Energy's Integrated Distribution Plan (IDP)?

ELPC/CEF/VS recommend the Commission accept Xcel Energy's Integrated Distribution Plan, contingent on the recommendations for additional information and next steps detailed below. In the following subsections, we discuss our concerns and recommendations, including those related to Xcel's:

- Inadequate plan for and development of Flexible Interconnection;
- Proactive capacity investments;
- Planned Net Load methodology and N-1 overload risk analysis;
- Targeted undergrounding proposal;
- DERMS roadmap and related proposals;
- Integration of equity considerations in its IDP and budget prioritization;
- Wildfire mitigation program; and,
- Overarching need for increased, deliberate coordination between various IDP-related initiatives, including: planned loading limits; Technical Planning Standard (TPS); feeder native loading standard; PNL methodology; proactive upgrades; reactive upgrade cost-sharing; Flexible Interconnection; Non-Wires Alternatives (NWA); proposed Capacity*Connect program; and proposed mobile battery system.

We summarize our specific recommendation in Section IV.

15. Did Xcel Energy adequately address the Commission's IDP filing requirements and prior Orders, as outlined in Attachment A to this notice?

No, Xcel has not adequately addressed the Commission's prior IDP Order points related to Flexible Interconnection. The Commission's 2024 Order called upon Xcel to demonstrate its ability to integrate DERs 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."[33] The Commission also required Xcel to be transparent about the conditions under which the Company will use FI, particularly with impacted DER owner/operators.[34] In addition, the Commission directed the Distributed Generation Workgroup to discuss Flexible Interconnection and "to work through questions related to Static Flexible Interconnection as well as Dynamic Flexible Interconnection which is enabled by DERMS."[35] In this IDP, Xcel has improperly dismissed static FI as a solution and disregarded the Commission's direction to implement a staged approach to Flexible Interconnection. Instead, it prioritizes only dynamic FI, which according to Xcel requires DERMS. In addition, Xcel's dynamic FI plan falls short of the level of detail contemplated by the Commission's 2024 Order, and its proposed timeline is too prolonged, especially as it is vulnerable to further delays that could occur if the planned rollout of DERMS is itself delayed.

To start, Xcel does not sufficiently justify its dismissal of static Flexible Interconnection and fails to recognize static FI's potential benefits. Static FI uses a power control system to prevent a DER system from exporting more power than a pre-set threshold, and can do so while

[33] 2023 Xcel IDP Order at 18, 26 ¶ 19.
[34] *Id.* at 26, ¶ 20.
[35] *Id.* at 26, ¶ 21.

varying the threshold by time-of-day: for instance, a 2 MW solar + 2 MW storage system would nominally have a maximum capacity of 4 MW, but could be limited by static FI to exporting 1 MW during peak grid congestion hours during the daytime.[36] The storage system could then discharge 2 MW after sunset, providing power during times of peak load. Static FI is a low-cost, simple option that could allow a DER to avoid or defer expensive distribution system upgrades and also contribute optimally to system resources. One of Xcel's concerns is that static FI will require detailed system studies to integrate the DER and set the amount of curtailment needed. However, detailed system studies would also be required for dynamic FI, and it would be more efficient to develop static and dynamic FI studies together due to shared requirements and process elements. Detailed system studies are not an entirely new requirement, as DER owners already need to pass some level of studies and inspections before interconnecting. And while static FI could theoretically require more curtailment than dynamic FI, a DER owner could still prefer static FI if they desired a higher degree of certainty as to when they could operate and how much power they can export, whereas dynamic FI curtailment would be less predictable and at the discretion of the grid operator. This benefit could prove crucial if Xcel can implement static FI relatively soon, and on a widespread basis, whereas a DER owner would have to wait years for dynamic FI to be available in their area.

Moreover, static and dynamic FI are complementary, not mutually exclusive. Dynamic FI has its own limitations that can be remedied by static FI: dynamic FI relies upon having a working communications link between the DER site and the utility, to set export limits based on current grid conditions.[37] But it is not uncommon for DERs to lose that communications link for

[36] *See In the Matter of Xcel Energy's 2023 Integrated Distribution Plan*, Docket No. E-002/M-23-452, Initial Comments of Grid Equity Commenters: Cooperative Energy Futures, Environmental Law & Policy Center, Sierra Club, and Vote Solar at 25 (Mar. 1, 2024).
[37] 2025 Xcel IDP at Ch. 7, p. 4.

short periods of time, especially during an initial rollout of DERMS while technical issues are still being identified and resolved.[38] Static FI provides a safe minimum fallback during such periods, which improves customer outcomes relative to zero-export requirements during such periods. And on a related topic, Xcel is considering dynamic flexible energization for interconnecting new loads on constrained grids, but some new load customers may prefer static flexible energization (*i.e.* a pre-scheduled capacity limit based on the season or time-of-day) if they must meet certain minimum operational needs even during grid constraints.[39]

Xcel's proposal for implementing dynamic FI is also inadequate, as it has failed to present key details about when and how dynamic FI will become available. Instead, Xcel does not plan to implement dynamic FI until it first develops the DERMS it claims are necessary for dynamic FI, and even then, Xcel only plans to start with a "limited DERMS deployment" in the third quarter of 2026.[40] Xcel's tentative timeline appears to spend half of 2026 and all 2027 selecting and developing the pilot sites, claims that it needs all of 2028 to run the pilot and evaluate the results, and finally labels 2029 through 2030 as "Scale, Adjust, or sunset."[41] Xcel has not provided details about what specific processes and practices it is developing for the DERMS, nor how it plans to select the first pilot sites and where they will be located. Over the next five years, the timeline does not indicate any timeframe for a systemwide rollout of dynamic FI. We also highlight that during workshops, Xcel explained that its initial plan for testing FI is to deploy only one FI per "circuit."[42] But the flip side is that Xcel must be prepared to eventually

[38] *See e.g.* New York State Electric and Gas, Flexible Interconnect Capacity Solution (FICS): Reforming the Energy Vision (REV) Demonstration Project, Q2 2024 Quarterly Report at 18, https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B80ED4B91-0000-C839-A43C-A68BB37C01D6%7D

[39] CHARGED, *Flexible Grid Connections Implementation Guide* at 53 (Jan. 2026), https://chargedinitiative.org/wp-content/uploads/2026/01/CHARGED-Flexible-Grid-Connections-Implementation-Guide.pdf.

[40] 2025 Xcel IDP at Ch. 7, p. 4.

[41] *Id.* at Ch. 7, p. 5.

[42] *Id.* at Ch. 9, p. 21.

support multiple FI interconnections per feeder, as a one-FI cap will starkly limit FI's effectiveness. Moreover, Xcel only says it "may consider expanding" dynamic FI after evaluating the initial results, which leaves it unclear whether Xcel believes its next step will be systemwide deployment or just another pilot.[43] Xcel's dynamic FI plan does not provide the level of detail contemplated by the Commission's 2024 Order. In addition, its proposed timeline is too lengthy and vulnerable to further delays that could occur if the planned rollout of DERMS is itself delayed.

ELPC/CEF/VS also disagree with Xcel's position, stated in its response to the Department's Information Request No. 86 (Attachment 2), that Flexible Interconnection and reactive cost-sharing (DSRUP) will be separate and mutually exclusive interconnection pathways. Xcel would require a customer to choose either of the options upfront, and they would not be allowed to later switch pathways. Such a restriction is misguided, as Flexible Interconnection and reactive cost sharing are inherently complementary solutions, as discussed in Section II.A above. Flexible Interconnection can provide a path to faster interconnection while reactive cost sharing can provide a means to curtailment relief without significantly burdening ratepayers with cost and risk. Together, Flexible Interconnection and reactive cost sharing can function as an alternative to proactive capacity upgrades.

In summary, Xcel must revise its Flexible Interconnection proposal to satisfy the Commission's 2024 order. ELPC/CEF/VS recommend that the Commission require Xcel to implement static FI in parallel with dynamic FI because static FI has fewer technology requirements and can be implemented faster than dynamic FI. The two Flexible Interconnection methods share foundational concepts and functionalities, which means that implementing static

[43] *Id.* at Ch. 7, p. 5.

FI will allow Xcel to gain valuable experience, which will facilitate the subsequent implementation of dynamic FI. In light of the Company's inadequate compliance with the Commission's prior Order on this topic, we also recommend that the Commission order Xcel to file, by December 31, 2026, a report on their FI efforts and plans in this docket and include a specific update on their progress towards implementing static FI. In addition, the Commission should order Xcel to include updated information on Flexible Interconnection in their 2027 IDP. ELPC/CEF/VS note that the DGWG has only just begun to discuss FI with its education session on February 18, 2026. We suggest that Xcel should incorporate and otherwise address discussions and learnings from the DGWG process in its 2026 and 2027 filings.

ELPC/CEF/VS also strongly recommend that the Commission require Xcel to review materials from Ameren and CHARGED, who have worked extensively on Flexible Interconnection and present key considerations. We recommend that Xcel incorporate these considerations into its program design and address these materials in its 2026 report and 2027 IDP. Ameren Illinois' *Flexible Interconnection and DER Orchestration Report* highlights a series of questions that utilities must answer in order to design a functioning dynamic FI program:

- How will available capacity be allocated amongst participating loads and DER?
- Who will be responsible for determining the estimated curtailment, and what supporting tools or data sharing infrastructure needs to be in place to support this analysis?
- What additional mechanisms, if any, are reasonable to protect applicants against higher than-expected curtailment?
- How will customer site design and equipment be impacted by communications and control requirements?

- What communications architecture, media, and equipment will be necessary to implement dynamic connections effectively?[44]

CHARGED's Flexible Grid Connections Implementation Guide (which we thank Xcel for helping develop as a working group participant) is also a useful resource.[45] We further discuss Xcel's plan for DERMS in Section III.B.16.h below.

16. Feedback, comments, and recommendations on the following areas of Xcel's IDP:

a. Forecasted distribution budget

According to this IDP, Xcel expects to make substantial investments in its distribution system from 2025 to 2030, focused on infrastructure renewal and capacity expansion, spending nearly $900 million per year and a total of over $5 billion during this period. The Company's capital budget is summarized in IDP Table 6-2 copied below.[46]

Table 6 - 2
Distribution Capital Expenditures Budget by IDP Category – State of Minnesota – Electric 2025-2030 (Millions)

	Bridge Year	Budget					Budget Avg
IDP Category	2025	2026	2027	2028	2029	2030	2026-2030
Age-Related Replacements and Asset Renewal	$392.9	$488.5	$474.3	$360.1	$338.5	$287.3	$389.7
New Customer Projects and New Revenue	$57.4	$61.0	$49.3	$54.4	$52.3	$53.9	$54.2
System Expansion or Upgrades for Capacity	$84.7	$230.6	$234.8	$187.0	$292.9	$248.1	$238.7
Projects related to Local (or other) Government-Requirements	$42.4	$48.2	$38.8	$40.5	$40.8	$33.8	$40.4
System Expansion or Upgrades for Reliability and Power Quality	$45.5	$50.7	$67.3	$106.3	$113.1	$116.8	$90.8
Other	$126.7	$58.8	$60.0	$70.6	$67.6	$63.3	$64.0
Metering	$10.2	$7.3	$7.2	$7.0	$7.0	$7.3	$7.2
Grid Modernization and Pilot Projects	$29.2	$16.4	$29.6	$0.0	$0.0	$0.0	$9.2
Non-Investment	($3.6)	($4.0)	($4.0)	($4.0)	($4.0)	($4.0)	($4.0)
Electric Vehicle Programs	$4.3	$18.4	$2.7	$3.2	$3.7	$4.3	$6.5
TOTAL	$789.6	$976.0	$960.0	$825.1	$911.9	$810.6	$896.7

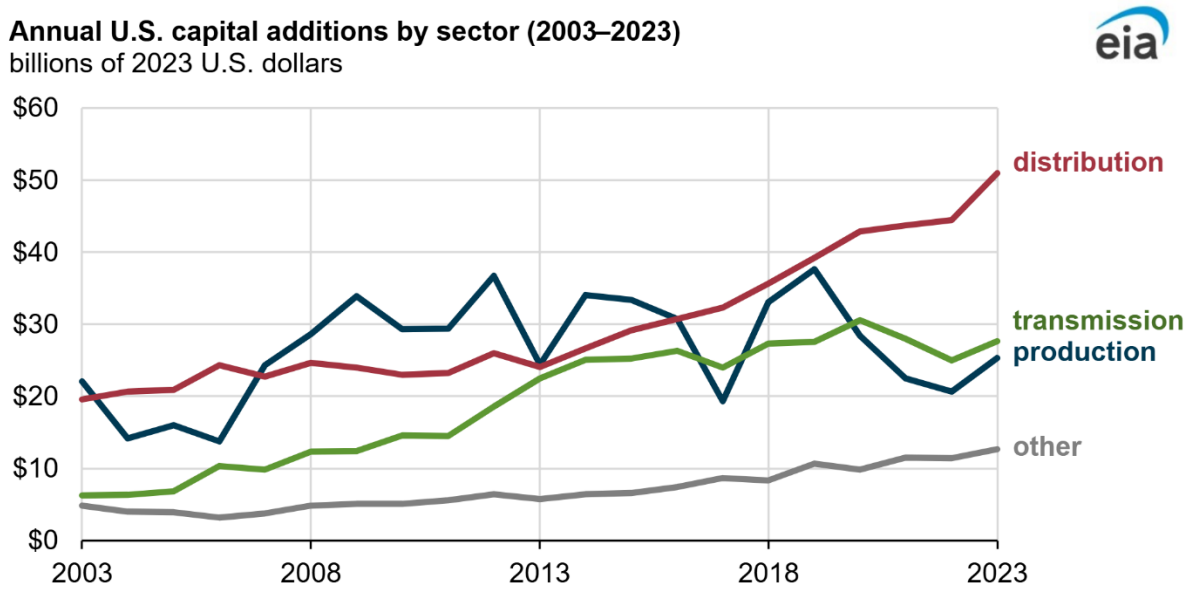
[44] Ameren Illinois, *Flexible Interconnection and DER Orchestration Report Phase 1* at 53 (Sept. 2025), https://www.ameren.com/-/media/files/account/service-options/renewables/illinois/resources/flexible-interconnection-orchestration-report-phase-1.ashx.
[45] CHARGED, *Flexible Grid Connections Implementation Guide* (Jan. 2026), https://chargedinitiative.org/wp-content/uploads/2026/01/CHARGED-Flexible-Grid-Connections-Implementation-Guide.pdf.
[46] 2025 Xcel IDP at Ch. 6, p. 12 (and related workpapers).

This reflects a dramatic increase over its prior actual spending in 2020-2024 of about $436 million per year, with a total of just over $2 billion.[47]

In its Information Request No. 89 (Attachment 3), the Department further demonstrated the significant increase in spending on key categories, comparing average annual spending in 2020-21 to 2026-30, and showing a 291% increase in age-related spending, a 500% increase in capacity spending, and a 215% increase in reliability spending. Responding to the Department's request to explain these increases, Xcel offered relatively limited additional detail. The Company also indicated in the same IR response that it expects the budgets to grow in all three areas in the 2031-36 period.

The significant budget growth—and the Company's expectation that it will continue—demonstrate how distribution spending is squarely at the heart of affordability. Looking across the United States, as shown in the figure below from the U.S. Energy Information Administration (EIA), while generation and transmission costs in recent years are relatively flat, distribution costs are rising steeply.[48]

[47] *Id.* at Ch. 6, p. 9 (and related workpapers).
[48] U.S. EIA, Grid infrastructure investments drive increase in utility spending over last two decades, https://www.eia.gov/todayinenergy/detail.php?id=63724 (last visited Feb. 26, 2026).



Processes like the Integrated Resource Plan (IRP), wholesale markets, and long-term regional transmission planning have helped to rein in generation and transmission costs. While the Integrated Distribution Plan has provided critical transparency and discussion around Xcel's distribution plans, it has thus far not seemed to discipline the Company's distribution spending, even in combination with the regular rate case review process. The Commission should evaluate this IDP's proposed budgets bearing in mind that the Company has an inherent incentive to make capital investments on which it can earn a rate of return. This underscores the need for very close scrutiny of the IDP's proposed investments, and the Commission should require Xcel to explore all ways to reduce the need for investments and minimize costs for customers. Throughout these comments, we make specific recommendations, including specific ways to better integrate and leverage DERs, with this goal in mind.

b. Forecasting results and methodology

ELPC/CEF/VS do not have comments specific to the Company's forecasting results and methodology at this time, although we may comment further in reply. However, we highlight the strong ties between forecasting and proactive upgrades, and the related importance of measuring

the Company's confidence in forecasts and their sensitivities to factors such as individual large loads or DERs. We noted that Xcel's response to the Department's Information Request No. 26 (Attachment 4) referenced its finding that its LoadSEER forecast for 2023/2024 was off by 500MW in 2023 (6% over) and 800 MW in 2024 (10% over). The Company explained this variation could be due to weather, and new customers not coming online in the year and size expected. These discrepancies impact confidence in the accuracy of the Company's forecasting needs going forward, especially since a 6% or 10% error in aggregate may mean significantly larger errors on specific substations, which may in turn trigger unnecessary proactive investments. ELPC/CEF/VS recognize that these issues are subject to ongoing discussion of Phase 2 of the proactive workgroup and mention them to underscore their importance to the Commission.

c. Proactive capacity investments

ELPC/CEF/VS commend Xcel for its progress so far on proactive upgrades and reactive cost-sharing, and we agree with Xcel that proactive capacity investments can be a valuable tool for unlocking additional hosting capacity for DERs. We appreciate Xcel's engagement with stakeholders in ongoing discussions about how to design cost-sharing mechanisms, and we agree with Xcel that grid upgrade costs should be allocated in an equitable manner that does not create a barrier for DERs seeking interconnection. That said, as the Proactive Distribution Upgrades Framework contemplates, proactive upgrades should be judicious and should be constructed only where forecasts indicate a high likelihood that they will be necessary.[49] ELPC/CEF/VS filed more detailed comments on Xcel's first Proactive Upgrade Proposal on January 28, 2026. While

[49] *In the Matter of a Commission Inquiry into a Framework for Proactive Distribution Grid Upgrades and Cost Allocation for Xcel Energy*, Docket No. E-002/CI-24-318, Order Establishing Framework for Proactive Distribution Grid Upgrades (Sept. 2, 2025).

we expressed concerns about the timing and necessity of that first Proposal, we are confident that Xcel will continue analyzing its forecasts for feeders and substations where proactive upgrades may be necessary and would encourage Xcel to identify any such needed upgrades in future IDPs.

We would also encourage Xcel to improve coordination between the many alternatives for increasing hosting capacity besides proactive upgrades. This includes mechanisms such as Flexible Interconnection, the proposed mobile battery system, Capacity*Connect battery energy storage system deployments, non-wires alternatives, and any variances to the planned loading limits, Technical Planning Standard (TPS), feeder native loading standard, and Planned Net Loading methodology. Xcel should raise the level of deliberate coordination between these alternative mechanisms and proactive upgrades, as they can each have the effect of increasing hosting capacity for distributed generation or load. While Xcel has given considerable thought to each of these alternatives on their own, in practice, we would like Xcel to pursue an integrated approach that considers the full menu of options for alleviating grid constraints. Xcel must consider these mechanisms together, evaluating actual overload risk and the timing of capacity needs, as many of these mechanisms have overlapping goals and benefits. An integrated, coordinated approach is necessary in order to maximize the combined value of these alternatives to the distribution grid.

As we noted in our previous comments on Xcel's Proactive Upgrade Proposal, Xcel understandably did not conduct an analysis of alternatives for its first Proposal, due to the limited turnaround time between when the Commission adopted the Framework and when Xcel was required to submit its Proposal. The Framework specifies this requirement in provision G.6, which requires Xcel to discuss in its filing: "Whether Xcel Energy performed a non-wires

alternative (NWA) for the project, and if so, a citation to the results of the analysis in its IDP. If Xcel Energy did not perform an NWA, provide a discussion of alternative measures, if any, that could be taken to mitigate the risk(s) the upgrade is intended to address, including energy-conservation, load-management measures and/or flexible interconnection." For future Proactive Upgrade Proposals, the Commission should require Xcel to conduct an integrated, coordinated analysis of alternatives, including use of Flexible Interconnection, potentially in tandem with DSRUP. Such analysis and discussion in any proactive upgrade proposals will allow the Company and the Commission to continue to improve integration between the various distribution planning options available to Xcel.

d. Updated Planned Net Load (PNL) methodology and risk analysis results

ELPC/CEF/VS express several disagreements with the IDP's methodology for modeling Planned Net Load and risk analysis. Xcel has not adequately evaluated alternative PNL methodologies and continues to unduly discount the capacity provided by DERs when modeling Planned Net Load. Meanwhile, Xcel's risk analysis for N-1 scenarios and contingency projects also relies on some unjustifiably conservative assumptions. In both cases, these overly conservative assumptions may lead Xcel to make unnecessary distribution system investments, which in turn result in higher distribution budgets than would be necessary under less conservative assumptions that still ensure robust safety and reliability. Given the very high capital budgets Xcel proposes in this IDP, we encourage the Commission to scrutinize these technical assumptions and methodologies. We describe our recommendations in further detail below.

Planned Net Load (PNL) Methodology

Xcel's PNL methodology fails to give due consideration to the capacity provided by DERs, and Xcel has not made adequate progress on evaluating alternative PNL approaches as contemplated by the Commission's 2024 Order. The Commission required Xcel to implement a 15% dependability factor for the 2025 IDP's N-0 risk analysis, which Xcel has done.[50] The Commission did not adopt the 15% dependability factor for subsequent IDP cycles going forward, but rather, ordered Xcel to continue working with stakeholders, evaluate alternative PNL methodologies, and revise its PNL approach.[51] The Commission specifically said that "the Company must include a report describing the results of this evaluation and changes to its proposed PNL methodology in its next IDP."[52]

Stakeholders presented multiple alternative methodologies to Xcel during the 2023 IDP comments and in subsequent workshops. In general, stakeholders commented that the 15% dependability factor was too conservative and excessively discounted the capacity contributions of DERs.[53] Stakeholders presented alternative methodologies such as seasonal dependability factors, incorporating different solar generation profiles based on geographic region, calculating PNL based on more granular, hourly generation profiles, and analyzing the loss of large solar installations as an N-1 planning contingency.[54] These alternative approaches are mature, demonstrated methodologies; they are available and have been used by utilities elsewhere, such as Southern California Edison's hourly, seasonal generation profiles for solar.[55]

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[50] 2023 Xcel IDP Order at 16; 2025 Xcel 2025 IDP at Ch. 1, pp. 88-89.
[51] 2023 Xcel IDP Order at 16.
[52] *Id.*
[53] *See In the Matter of Xcel Energy's 2023 Integrated Distribution Plan*, Docket No. E-002/M-23-452, Initial Comments of Grid Equity Commenters: Cooperative Energy Futures, Environmental Law & Policy Center, Sierra Club, and Vote Solar at 38-39 (Mar. 1, 2024).
[54] *In the Matter of Xcel Energy's 2023 Integrated Distribution Plan*, Docket No. E-002/M-23-452, Xcel Materials – Planned Net Loading Workshop 2 at pp. 16-23 (June 10, 2025).
[55] *Id.* at 24.

However, the 2025 IDP barely discusses these alternative methodologies. The 2025 IDP compared the number of nodes (feeders or substations) that would be overloaded under the 15% dependability factor versus under native load (*i.e.* ignoring DER generation entirely), and found that only nine nodes would be significantly impacted.[56] In contrast, the IDP did not perform this number-of-nodes calculation for any PNL methodologies other than the 15% dependability factor. In particular, the IDP did not compare the impacts of seasonal dependability factors versus a flat 15% factor and failed to evaluate the extent to which seasonal dependability factors would better mitigate overloading at nodes. It stands to reason that since feeders tend to be summer-peaking, and seasonal dependability factors are much higher than 15% during the summer, adopting seasonal dependability factors could have substantial impacts, and yet Xcel failed to model—or neglected to present its modeling of—this fairly intuitive conclusion. Instead, the 2025 IDP merely summarizes stakeholder input at the PNL workshops and fails to deliver a substantive assessment from Xcel in response to stakeholder proposals.[57]

The only alternative PNL methodology that Xcel has committed to adopting is using seasonal dependability factors in its 2027 IDP.[58] Yet even that proposal is short on detail. Xcel does not quantify what percentages it would use for the seasonal dependability factors, even though average solar generation output data is readily available to Xcel and is indeed presented in a month-by-month table in the 2025 IDP.[59] Xcel's slow pace of progress on the PNL methodology is frustrating, considering that seasonal dependability factors were discussed in the 2023 IDP comments, yet will have taken four years to implement in any detail assuming that

[56] 2025 Xcel IDP at Ch. 1, p. 88.
[57] *Id.* at Ch. 9, pp. 6-9. The only proposal that Xcel gave a substantive reason for rejecting was incorporating Effective Load Carrying Capacity (ELCC) into the PNL calculation. Xcel acknowledged suggestions such as using more granular hourly solar generation data and evaluating PNL during the loss of a Community Solar Garden, but Xcel's only response was that these proposals required "further investigation" or "further thought." *Id.* at Ch. 9, p. 9.
[58] *Id.* at Ch. 9, p. 9
[59] *Id.* at Ch. 1, pp. 87, 90.

they are realized in Xcel's 2027 IDP. Xcel has not justified such a prolonged timeline given that it already has seasonal solar generation data and the adjusted PNL calculation should be straightforward.

Xcel's 2025 IDP has failed to substantively describe the results of its evaluation of alternative PNL methodologies and failed to provide anything more than minimal details on changes to its proposed PNL methodologies. The Commission should order Xcel to rectify these deficiencies during the current IDP cycle. We request that the Commission order Xcel to file, by December 31, 2026, an interim update that: (1) demonstrates that it has given due consideration to the alternative PNL methodologies presented by stakeholders and substantively evaluates those methodologies; (2) provides specific details about the seasonal dependability factors, including the percentages it plans to use and which months would apply to each season; and (3) analyzes the impacts of those seasonal dependability factors. The Commission should also order Xcel to address its implementation of these topics in its 2027 IDP.

Risk Analysis for N-1 Scenarios and Contingency Projects

ELPC/CEF/VS have concerns that Xcel's risk analysis methodology identifies N-1 scenarios and contingency projects that are not justified or necessary for system reliability. Unlike N-0 overloads, N-1 scenarios are contingency risks: they are much less likely to occur in a given year than N-0 overloads because the N-1 feeder/transformer loss must coincide with times of high load where adjacent feeders are then unable to handle the transferred load from the feeder/transformer outage. Because any specific N-1 scenario often has a low probability of occurring in a given year, the combined probability of such events occurring during peak load periods is even lower. As a result, such probability-adjusted customer outage impact calculations often have benefit-cost ratios much lower than 1.

We would further note that of the 115 N-1 scenario mitigation projects listed in Attachment E of Xcel's 2025 IDP, 81 of those N-1 mitigations (about 70%) have a Risk Score of less than 1. Xcel has described the Risk Score as a benefit-to-cost ratio based upon the jurisdictional financial and reliability benefits, and the annualized costs of the project.[60] In comparison, Attachment E identifies 77 N-0 scenario mitigation projects, of which only 24 (about 31%) have a Risk Score of less than 1. Overall, this gives us concerns that N-1 mitigations tend to have fewer benefits than N-0 mitigations and we are concerned that many of the N-1 mitigations identified by Xcel may not be necessary.

Moreover, Xcel's N-1 scenario planning may be overestimating the risk of customer outages. Xcel intentionally limits its planning criteria to using equipment normal capacity ratings, but during operations, Xcel allows their system operators to run equipment to (higher) emergency ratings. Using emergency ratings in operations is common for many different utilities and gives the system flexibility to respond to contingency events. The tradeoff is that the utility accepts minor decreases in equipment lifespans caused by temporarily running over the normal ratings and is thereby able to restore customers that would otherwise have to be disconnected and would have increased the Customer Minutes Out. But our understanding is that Xcel's system planning does not take emergency ratings into consideration for N-1 conditions, which leads to increased mitigation costs to resolve.

Given these concerns around Xcel's over-conservative assumptions and the high budgets it proposes during this IDP term and foresees continuing, the Commission should direct Xcel to engage stakeholders regarding modifications to its risk analysis and planning methodologies to improve cost-effectiveness while still maintaining safety and reliability, including consideration

[60] 2025 Xcel IDP at Attachment D, p. 1.

of: (1) application of CMO calculation to planning for N-1 scenarios; and (2) use of emergency ratings in planning for N-1 conditions. In its next IDP, Xcel should discuss its stakeholder engagement efforts and explain any changes it has made in response and/or why it has not incorporated stakeholder recommendations.

e. Targeted undergrounding proposal

In this IDP, Xcel describes its $233.7 million targeted undergrounding proposal from 2025-2030.[61] ELPC/CEF/VS appreciate Xcel's more detailed description of its targeted undergrounding plans, which we have previously requested the Company provide in its IDP. We also appreciate the Company's discussion of its use of directional boring to minimize community disruption and its planned customer and community engagement efforts.[62] Regarding the latter, the Company states: "These efforts will be tailored to reflect the unique characteristics of each service area, including language accessibility, cultural considerations, and local governance structures. Particular attention will be given to areas identified through the third-party equity evaluation as underserved or historically disadvantaged, ensuring that engagement is inclusive and equitable."[63] ELPC/CEF/VS support Xcel's engagement plans.

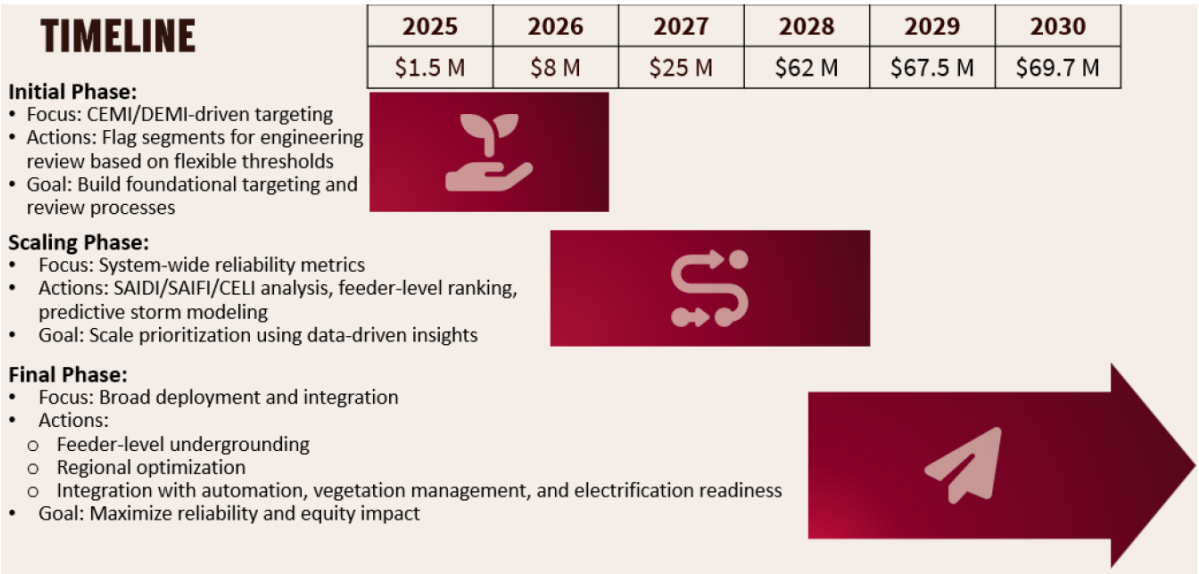
However, although Xcel previously highlighted the potential for targeted undergrounding to address identified disparities in reliability, as discussed in Section II.C above, it appears that the Company has indefinitely postponed meaningful integration of equity into its program as described in this IDP. Xcel states that, "[w]hile technical criteria such as outage frequency, duration, and asset condition will guide early deployment, equity and demographic considerations will be informed by the results of an independent third-party evaluation."[64] The

[61] 2025 Xcel IDP at Ch. 2, pp. 5-24.
[62] *Id.* at Ch. 2, pp. 21-24.
[63] *Id.* at Ch. 2, p. 24.
[64] *Id.* at Ch. 2, p. 6.

Company later similarly states: "To ensure equitable investment, the Company will incorporate findings from an independent third-party evaluation. This evaluation will inform demographic analysis to identify underserved or vulnerable communities, and community engagement strategies coordinated with local stakeholders and municipalities."[65] However, Xcel provides no detail on what relevant findings it expects to get from the study, which ELPC/CEF/VS understand will examine the Company's capital investment and other internal processes. Moreover, Xcel does not explain how or when it will integrate these findings or equity and demographic considerations in general into its targeted undergrounding plans and processes. Similarly, in IDP Figure 2-9 copied below, the Company identifies its focus on engineering review to drive targeted undergrounding projects in both its Initial and Scaling Phases.[66] Only in the Final Phase does the Company identify the goal to "maximize reliability and equity impact." But the Company offers no explanation for when this Final Phase will occur or how it will maximize its equity impact.

[65] *Id.* at Ch. 2, p. 20.
[66] *Id.*

Figure 2-9
Project Timeline



Especially given the large budget proposed, ELPC/CEF/VS recommend that the Commission require Xcel to integrate equity considerations explicitly and transparently into its targeted underground program from the start to ensure that communities facing disparities in reliability appropriately benefit in a timely manner. In addition, as discussed further below in Section III.B.17 with respect to integrating equity considerations into planning more generally, we suggest that the Commission require the Company to explore using the Interruption Cost Estimate (ICE) 2.0 Calculator from Lawrence Berkeley National Laboratory to inform this integration. To the extent the ongoing third-party study provides additional insights, Xcel should incorporate those, as well; however there is no reason to delay consideration of equity when the Company has already identified disparities in reliability and targeted undergrounding as a solution.

ELPC/CEF/VS also recommend that the Commission require Xcel to report annually on its targeted undergrounding program. We suggest these reports should include the following

data: number of undergrounding projects; number of projects in Environmental Justice areas; actual undergrounding project costs; drivers for projects (engineering, equity, other); and description of community engagement efforts.

f. Proposed cost-benefit analysis for discretionary distribution system investments

In its September 24, 2024 Order on Xcel's last IDP, the Commission required Xcel to conduct stakeholder engagement related to cost-benefit analysis for discretionary distribution system investments via two order points:

> 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.
>
> 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.

Xcel describes its efforts related to these order points in this IDP.[67]

As in Xcel's last IDP, ELPC/CEF/VS continue to support such cost-benefit analyses as a way for the Commission and stakeholders both to promote cost-effectiveness and affordability, and to understand better how Xcel incorporates ratepayers' interests and other policy goals into its distribution spending decisions. The benefits that Xcel considers in turn inform how a budget item may be prioritized. We look forward to reviewing other stakeholders' comments and Xcel's reply comments on this topic and may comment further in reply.

g. Non-Wires Alternative Analysis

ELPC/CEF/VS recognize that Xcel relies on its Non-Wires Alternative (NWA) process to explore DER alternatives to traditional infrastructure investments.[68] We strongly support this

[67] 2025 Xcel IDP at Ch. 6, pp. 21-24; Ch. 9, pp. 10-15.
[68] *Id.*, Ch. 8.

goal in concept. However, the NWA effort has faced various challenges and our understanding is that it has resulted in very limited, if any, construction of non-wires solutions to date. As Xcel states, its NWA process is "highly manual and cost intensive," and applies only to projects with costs exceeding $2 million.[69] With its Capacity*Connect proposal, discussed above in Section II.B, the Company has begun to explore a different avenue towards DER solutions. It has also proposed a mobile battery in this case, which is a different type of distributed, non-wires solution. We are hopeful that through its work on Capacity*Connect the Company will develop a mechanism by which to value DERs and learnings around how to dispatch them for distribution value. Given this potential, ELPC/CEF/VS suggest that Capacity*Connect should be an effective complement to, and possibly an eventual replacement of, the NWA process. While ELPC/CEF/VS do not make any specific NWA recommendations at this time, we look forward to reviewing other parties' comments and Xcel's reply comments, and may comment further in our reply.

h. Distributed Energy Resource Management System (DERMS)

The Commission's 2024 Order required Xcel to provide additional information about how it plans to incorporate DERMS as part of a staged approach for implementing Flexible Interconnection, DERMS, and dynamic hosting capacity.[70] Specifically, the Commission ordered Xcel to engage with stakeholders and address feedback as to the cost, benefits, purposes, and other key aspects of DERMS.[71] The Commission further ordered Xcel to file a detailed roadmap

[69] *Id.* at Ch. 8, pp. 19, 21.
[70] 2023 Xcel IDP Order at 18.
[71] *Id.* at 26, ¶ 22.

for DERMS deployment addressing a list of questions set forth in the Order.[72] In advance of this 2025 IDP, Xcel held two stakeholder workshops on DERMS.[73]

Overall, the 2025 IDP represents an important first step towards implementing DERMS in an appropriate manner, ensuring that any DERMS investments are well-justified by their intended use case(s) and the Company has considered alternative approaches. From the Company's discussion in this IDP, it is clear that it expects its DERMS adoption to be an iterative process, through its implementation of Aggregator DERMS, Grid DERMS and, eventually, Enterprise DERMS.[74] We suggest that the Commission continue to require transparency in the Company's implementation process in its IDPs. The Commission's scrutiny of and oversight over the Company's DERMS plans and budgets will help to ensure that Xcel's investments are cost-effective and the Company maximizes their benefits to customers through the identified use cases.

ELPC/CEF/VS note that DERMS is not necessarily mutually exclusive to the DERMS alternatives discussed by the IDP, such as the status quo approach.[75] In practice, utilizing DERMS may make more sense in some situations while the alternatives may be better suited in others and Xcel should choose whichever is more cost-effective for a particular situation or grid constraint. The most important benchmarks for the DERMS implementation process are that: DERMS must support well-defined, beneficial use cases; and the Company should coordinate with DER owners/operators to ensure that it integrates the needs and interests of DERs into its intended use cases for DERMS, such that these uses cases are actually feasible and realize their intended benefits.

[72] *Id.* at 26, ¶ 23.
[73] 2025 Xcel IDP at Ch. 9, pp. 15-22.
[74] *See, e.g.*, *id.* at Ch. 11 at 4-7 (discussing DERMS implementation timeline and phases).
[75] *Id.* at Ch. 11, pp. 10-12.

Xcel proposes to first implement Aggregator DERMS and Grid DERMS. For Grid DERMS, Xcel has identified three primary use cases, two of which are to aid the Flexible Interconnection of DERs and the flexible energization of new loads seeking to interconnect to constrained portions of the grid. The third use case is for battery energy storage systems (BESS) in Xcel's proposed Capacity*Connect program. In general, we believe that Grid DERMS could be effective at facilitating Flexible Interconnection, but we reiterate our comments from Section III.B.15 above that DERMS should not be cited as a basis for sidelining static Flexible Interconnection, which has significant benefits and Xcel can implement in the nearer term, without DERMS. Similarly, relying on DERMS risks delaying Xcel's proposed dynamic FI pilot if the rollout of DERMS itself is delayed.

As we have emphasized in these comments and in Xcel's prior IDP, offering effective Flexible Interconnection—both static and dynamic—is a critical next step for Xcel in Minnesota and the Company should pursue it in a phased manner rather than delay its implementation pending DERMS investments. In addition, it is essential for Xcel to engage with DER owners/operators on its implementation of Flexible Interconnection, including dynamic FI through DERMS. The Commission's roadmap questions in the prior IDP illustrate some of the core interactions between the Company and DER owners/operators, which the Company will need to continue to address as it rolls out its use of DERMS in Flexible Interconnection.

As for the Capacity*Connect use case, we refer to our comments in the Capacity*Connect docket, discussed above in Section II.C, and reiterate that Xcel should aim to use its proposed Limited Grid DERMS to learn how to co-optimize both bulk and distribution value.[76] Xcel faces a choice with dispatching battery storage resources in the Capacity*Connect

[76] *In the Matter of Northern States Power Company, dba Xcel Energy, Petition for Approval of Capacity*Connect, a Distributed Capacity Procurement (DCP) Program*, Docket. No. E002/M-25-378, Initial Comments of Cooperative

program: to dispatch storage to target specific distribution-level constraints; or to dispatch storage in response to bulk system needs, such as a signal from MISO.[77] By using its proposed Limited Grid DERMS to dispatch storage resources for distribution-level constraints at least some of the time, Xcel can begin to justify its Capacity*Connect DERMS use case. We have recommended that the Commission require Xcel to document when and how the DERMS dispatch decisions reflect tradeoffs between bulk and distribution needs, and incorporate those learnings into its ongoing Grid DERMS implementation.[78] Xcel has characterized the purpose of Grid DERMS as "ensur[ing] that DER operations stay within distribution grid limits."[79] The Capacity*Connect use case will be consistent with the scope of Grid DERMS only if it provides some stable and predictable benefits to the distribution grid, which it will not if it is aimed purely at bulk system dispatch.

For the Aggregator DERMS, Xcel has identified two use cases: scalable DER management; and enhanced grid visibility and control.[80] We would encourage Xcel to elaborate on these use cases with additional details. For the scalable DER management, Xcel has said that it intends to integrate "a broader range of DERs" within the Company's demand management programs and we would appreciate Xcel's clarification whether that means this use case will only apply to demand response resources.[81] Xcel has also said that the Aggregator DERMS will help facilitate control of behind-the-meter solar arrays and we would appreciate an explanation of where that fits into either of these two use cases.[82] Xcel should also consider whether either of

Energy Futures, Environmental Law and Policy Center, Institute for Local Self-Reliance, Solar United Neighbors, and Vote Solar at 25 (Dec. 10, 2025).
[77] *Id.* at 25-26.
[78] *Id.*
[79] 2025 Xcel IDP at Ch. 11, p. 2.
[80] *Id.* at Ch. 11, p. 14.
[81] *Id.*
[82] *Id.* at Ch. 11, p. 2.

these use cases could help support electric school bus or vehicle-to-grid power injection on the generation side, and electric vehicle charging on the load side.[83] If these cross-program ties are cost-effective, they could help support Xcel's Transportation Electrification Plan.

Given Xcel's phased approach to DERMS implementation, and the ongoing efforts to refine its key uses cases, including Flexible Interconnection and Capacity*Connect, ELPC/CEF/VS again underscore the need for ongoing Commission oversight of Xcel's DERMS plans, budgets, and investments. While Xcel's future rate cases will allow the Commission to determine whether the Company's DERMS investments are prudent and the Company should receive cost recovery, we recommend that the Commission require Xcel to continue to describe its DERMS plans, use cases, and stakeholder engagement in its Integrated Distribution Plans. According to this IDP, by its next IDP in 2027, Xcel will only have deployed Grid DERMS in "limited use cases." More widespread deployment and "future integration of Aggregator DERMS with Grid DERMS" will occur after 2027, and Enterprise DERMS is part of the Company's "long term vision."[84] By continuing to exert oversight in Xcel's IDPs over the Company's plans as it rolls out its phases of DERMS, the Commission can ensure that the Company continues to make only necessary, cost-effective DERMS investments and realizes the expected benefits in its intended DERMS use cases.

17. Other areas of Xcel's IDP or TEP not listed above, along with any other issues or concerns related to this matter.

DER Interconnections—Rooftop Solar

ELPC/CEF/VS acknowledge the progress Xcel has made in interconnecting additional DERs over the last two years. Xcel's 2023 IDP reported that it had interconnected 10,283

[83] *See id.* at Ch. 5, p. 49 & Ch. 6, pp. 31-32.
[84] *Id.* at Ch. 11, pp. 4-7.

rooftop solar installations, with a total capacity of 162 MW.[85] In comparison, Xcel's 2025 IDP reports that it has interconnected 16,475 rooftop solar installations, with a total capacity of 264 MW.[86] This represents 102 MW of new rooftop solar capacity, an impressive growth rate of 63% since 2023. During the same period, Xcel also reports adding 72 MW of community solar, 13 MW of distributed wind, and 4 MW of distributed storage.[87] These capacity additions are significant, and ELPC/CEF/VS urge Xcel to take steps to maintain and build upon its progress interconnecting distributed resources. As discussed above in these comments, we also encourage Xcel to better integrate and leverage these DERs as distribution resources.

Looking ahead, Xcel has the opportunity to increase the rate at which MW of rooftop solar are added to the grid. Xcel's 2025 IDP reports 4,926 projects in the queue with a combined capacity of 1,262 MW.[88] In comparison, in 2023 Xcel had 3,939 rooftop solar projects queued, but they only accounted for 93 MW of capacity.[89] The growth in the number of queued projects is far outpaced by the growth of the size of these projects, as the composition of the rooftop solar queue has shifted as more large commercial customers are seeking to interconnect. In 2023, only 3 rooftop solar projects in the queue were larger than 1 MW, whereas in 2025, Xcel's data shows that there are 254 projects with a capacity greater than 1 MW in the rooftop solar queue, many of which are between 4 and 5 MW.[90]

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[85] *In the Matter of Xcel Energy's 2023 Integrated Distribution Plan*, Docket No. E-002/M-23-452, Xcel's 2023 Integrated Distribution Plan, Appendix E at 27 (Nov. 1, 2023); *see also Annual Report Distributed Generation Interconnections*, Docket No. E-999/PR-23-10, Xcel's Distributed Energy Resource (DER) Interconnection Report – Errata – Attachment A (Apr. 24, 2023).
[86] IDP, Chapter 7 at 17; *see also Annual Report Distributed Generation Interconnections*, Docket No. E-999/PR-25-10, Xcel's Distributed Energy Resource (DER) Interconnection Report– Attachment A (Feb. 28, 2025).
[87] *In the Matter of Xcel Energy's 2023 Integrated Distribution Plan*, Docket No. E-002/M-23-452, Xcel's 2023 Integrated Distribution Plan, Appendix E at 27 (Nov. 1, 2023); 2025 IDP, Chapter 7 at 17.
[88] 2025 IDP, Chapter 7 at 17.
[89] *In the Matter of Xcel Energy's 2023 Integrated Distribution Plan*, Docket No. E-002/M-23-452, Xcel's 2023 Integrated Distribution Plan, Appendix E at 27 (Nov. 1, 2023).
[90] *Annual Report Distributed Generation Interconnections*, Docket No. E-999/PR-23-10, Xcel's Distributed Energy Resource (DER) Interconnection Report – Errata – Attachment A (Apr. 24, 2023); *Annual Report Distributed*

	2023		2025	
Installation size (kW)	**Capacity**	**# of Projects**	**Capacity**	**# of Projects**
Less than 20 kW	25.1 MW	3,334	24.5 MW	3,405
20 – 100 kW	16 MW	371	13.9 MW	320
100 – 500 kW	23.1 MW	98	26.2 MW	108
500 – 1000 kW	19.8 MW	25	40.4 MW	47
More than 1000 kW	9.1 MW	3	1,157 MW	254
Not provided/blank	-	108	-	792
Total	**93.1 MW**	**3,939**	**1,262 MW**	**4,926**

These large rooftop solar projects pose both a potential challenge and opportunity for Xcel, as we emphasized in discussing Xcel's forecasts for DERs in the 2025-2030 time period in Section II above. Larger DERs like those in the current queue typically must undergo more rigorous studies to interconnect and are more likely to require distribution grid upgrades, so they are at greater risk of being delayed. Xcel should ensure that it devotes sufficient resources to reviewing these projects and must not allow the queue to become backlogged. An effective Flexible Interconnection program can help to support this goal.

Integration of Equity Considerations

As discussed in Section II.C above, ELPC/CEF/VS continue to recommend transparent integration of equity considerations into Xcel's distribution planning and investment prioritization. To be clear, we do *not* recommend that equity be the only or the top-priority

Generation Interconnections, Docket No. E-999/PR-25-10, Xcel's Distributed Energy Resource (DER) Interconnection Report– Attachment A (Feb. 28, 2025).

consideration, but rather that Xcel explicitly and transparently incorporate it into its planning and investment decision-making alongside traditional engineering and economic factors.

Currently, it appears that Xcel does not consider equity in its planning and investments at all. For example, in response to Fresh Energy Information Request No. 8 (Attachment 5), Xcel described how it identifies, prioritizes, and determines budgets for routine asset health projects each year:

> Assets are identified through condition assessments, age, failure history, and inspection data, with emergent needs such as storm damage incorporated into planning. Projects are prioritized based on reliability, safety, and system performance, with key programs including cable and pole replacement, substation renewals, and discrete rebuilds. Annual budgets are determined using historical spending trends, forecasted failure rates, and lifecycle analysis, and are adjusted for emergent work and economic conditions. These investments are strategically aligned to maintain reliability, enhance grid resilience, and support long-term lifecycle management

The Company made no indication that it considers equity at any point in these processes. Xcel's description of how it identifies, prioritizes, and determines budgets for discrete asset health projects and asset replacement in the Substation Renewal Program, in response to Fresh Energy Information Request No. 9 and 13 (Attachments 6 and 7) are similar, with no mention of equity. Likewise, when describing its risk analysis for projects included in its current budget in response to Fresh Energy Information Request No. 28 (Attachment 8), Xcel stated: "Budget decisions incorporate other system priorities—including reliability, resiliency, asset health, and long-term planning needs—so capacity loading alone does not dictate whether a project is included." Xcel does not appear to consider equity in its budgeting decisions.

In its IDP discussion of "Equity Considerations in Planning," Xcel points to its ongoing third-party study, required by the Commission in its January 13, 2025 Order in Xcel's last SRSQ

proceeding (Docket No. 24-27) and mentioned above in Section II.C.[91] Xcel indicates that the study "will assess our practices and policies related to capital investment planning, outage restoration, and disconnections, with a focus on identifying any racial disparities."[92] Xcel also states that the study "will include stakeholder engagement throughout its design and implementation," which the Commission required in its Order.[93] ELPC/CEF/VS look forward to reviewing the study and engaging with Xcel to implement its recommendations.

As discussed above in Section II.C, however, this study does not preclude the Commission from requiring the Company to begin to integrate equity considerations in its planning and budgets in this IDP proceeding. Rather, the study should serve to further inform Xcel's efforts. As we discussed in testimony in Xcel's pending rate case (Docket 24-320), leading utilities have already begun to embed equity directly into their capital allocation and project prioritization processes.[94] For example, DTE Electric in Michigan has integrated equity and environmental justice considerations into its global prioritization model that it uses for both distribution system planning and in developing rate case investment proposals.[95] Similarly, Consumers Energy, also in Michigan, has added an "equity flag" to its project scoring model that elevates investments benefiting historically underserved communities in the prioritization

[91] 2025 Xcel IDP at Ch. 7, p. 11.
[92] *Id.*
[93] *Id.*; 24-27 Xcel SRSQ Order at 15, ¶ 46 ("Xcel must engage interested stakeholders to participate and collaborate with the independent third-party evaluator.").
[94] Docket Nos. E-002/GR-24-320 & E-002/M-24-321, *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota*, Surrebuttal Testimony of William D. Kenworthy on behalf of the Joint Intervenors, at 7-12 (Nov. 25, 2025) ("Kenworthy Surrebuttal (Docket No. 24-320, Xcel Rate Case)"); Docket Nos. E-002/GR-24-320 & E-002/M-24-321, *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota*, Direct Testimony of William D. Kenworthy on behalf of the Joint Intervenors, at 11-15 (Aug. 22, 2025) ("Kenworthy Direct (Docket No. 24-320, Xcel Rate Case)").
[95] Direct Testimony of A.J. Kryscynski on behalf of DTE Electric Company before the Michigan Public Service Commission, *In the matter of the Application of DTE ELECTRIC COMPANY for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority*, U-21860, Aug. 15, 2025, pp. 41-64.

process.[96] Both of these approaches represent the integration of equity into core utility planning and budgeting processes, ensuring that equity considerations influence fundamental investment decisions.

Consistent with our recommendations in Xcel's pending rate case, ELPC/CEF/VS recommend that the Commission require Xcel, before filing its next IDP on November 1, 2027, to:

1. Establish equity-informed prioritization criteria for distribution investments. The Commission should require Xcel to develop and implement systematic criteria that prioritize investments addressing documented service disparities. The Company should weight these criteria appropriately in its distribution project scoring and prioritization processes.
2. Integrate equity requirements into the IDP process. The Commission should require Xcel to demonstrate in its IDP filings how it will systematically and transparently incorporate equity considerations into distribution planning and investments. We note that this may mean that the Company would prioritize system upgrades in communities, that would bear disproportionately greater impacts from outages, such as spoiled food or medicine, including low-income and otherwise vulnerable communities.
3. Implement transparent reporting on equity outcomes. The Commission should require Xcel to report on reliability improvements and infrastructure investments by environmental justice area, income level, and racial composition in its Safety, Reliability, and Service Quality annual reports, just as the Company reports on

[96] Direct Testimony of Micheal P. Kelly on behalf of Consumers Energy Company before the Michigan Public Service Commission, *In the matter of the application of CONSUMERS ENERGY COMPANY for authority to increase its rates for the generation and distribution of electricity and for other relief,* U-21870, June 2, 2025, p. 74.

reliability or other dimensions of utility performance. This reporting should demonstrate whether rate-funded investments are systematically addressing documented disparities or perpetuating inequitable service patterns.

Xcel should discuss its implementation of these requirements in its 2027 IDP.

In addition, ELPC/CEF/VS recommend that the Commission require Xcel to explore use of the Interruption Cost Estimate 2.0 methodology from Lawrence Berkeley National Laboratory to identify and prioritize investments in low-income and other vulnerable communities.[97] We also discussed the LBNL ICE 2.0 methodology in Xcel's pending rate case, noting that it provides a new, more robust approach to analyzing outages costs to inform distribution investments with equity considerations.[98] The ICE 2.0 analysis can be combined with social vulnerability mapping to create powerful equity analysis. For example, utilities could overlay ICE 2.0 cost estimates with environmental justice screening tools to identify "equity hotspots"—areas where high calculated outage costs coincide with communities that have limited adaptive capacity to cope with and recover from outages. We encourage the Commission to require the Company to leverage this tool in its planning and operations to advance equity.

Wildfire Mitigation

Xcel describes Wildfire Mitigation Plan in its IDP and proposes a very high budget of approximately $834 million in total capital spending for its efforts in 2026-2030, as detailed in IDP Table 2-3 copied below.[99]

[97] The newest version 2.0 of the ICE Calculator is available at: https://icecalculator.com.
[98] Kenworthy Direct (Docket No. 24-320, Xcel Rate Case) at 9-10; Kenworthy Surrebuttal (Docket No. 24-320, Xcel Rate Case) at 10-12.
[99] 2025 Xcel IDP at Ch. 2, pp. 24-29 (Table 2-3 on p. 29); *see also* 2025 Xcel IDP at Ch. 6, p (Figure 6-4 – showing a 2026-30 wildfire capital budget of $845.3 million). Xcel notes that "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." 2025 Xcel IDP at Ch. 2, p. 29, n.14.

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

Although ELPC/CEF/VS view wildfire mitigation as a necessary and important program, we suggest that such a high-budget, substantial program necessitates a more detailed description of the Company's strategy and decision-making than the five or six pages provided in this IDP. In particular, the Company has not provided a detailed risk-spend assessment for stakeholder and Commission review. Without this assessment, it is not possible to fully evaluate the timing and cost-effectiveness of its proposed wildfire mitigation investments or compare them to the other investments the Company proposes to make. We note that we discussed these concerns in testimony in Xcel's pending rate case (Docket No. 24-320).[100]

ELPC/CEF/VS recognize that Xcel must fully justify the prudency of its investments in its rate case—and indeed, some of these wildfire investments are at issue in the Company's current rate case. Prior to cost recovery, however, the Commission and stakeholders should have the opportunity to scrutinize and evaluate any new large-scale distribution investment program within the established Integrated Distribution Plan process. In this way, the Commission and stakeholders can first clearly understand risks, costs, and benefits of proposed wildfire mitigation investments, and assess how the Company proposes to prioritize wildfire investments alongside other capital needs. Only after the Company has received stakeholder input and Commission review should it seek cost recovery for investments within this new program.

[100] Kenworthy Direct (Docket No. 24-320, Xcel Rate Case) at 15-23; Kenworthy Surrebuttal (Docket No. 24-320, Xcel Rate Case) at 18-22.

Therefore, ELPC/CEF/VS recommend the Commission require Xcel to provide a supplementary filing in this docket by December 31, 2026, that includes: (1) a detailed, Minnesota-specific wildfire risk assessment; and (2) evaluates wildfire risk both (a) in relation to Xcel's other jurisdictions, such as Colorado and Texas, where urgent mitigation investments may be more pressing, and (b) relative to other safety and reliability risks in Minnesota's distribution system. This supplementary filing should also include discussion of how these analyses support Xcel's specific investment proposals. This information will allow stakeholders to comment on and assess Xcel's proposed wildfire mitigation strategies and investments.

IV. CONCLUSION

With Xcel planning to make $5 billion in capital investments over the five-year IDP period, and the ongoing affordability challenges that Xcel's customers face, it is especially important to ensure that the Company's distribution investments are necessary and cost-effective. In these comments, ELPC/CEF/VS have provided recommendations to cost-effectively integrate and leverage DERs at a faster pace, which can help to avoid or defer traditional, expensive distribution investments. We have also underscored the need to integrate equity considerations into the Company's planning and investments, to ensure customers experience the benefits of these investments in an equitable way. In sum, ELPC/CEF/VS recommend that the Commission:

- Accept Xcel Energy's Integrated Distribution Plan, contingent on the recommendations for additional information and next steps detailed in these comments.

- Require Xcel to revise its Flexible Interconnection proposal to satisfy the Commission's 2024 order. Specifically, ELPC/CEF/VS recommend that the Commission:
  - Require Xcel to implement static FI in parallel with dynamic FI because static FI has fewer technology requirements and can be implemented faster than dynamic FI;
  - Order Xcel to file, by December 31, 2026, a report on their FI efforts and plans in this docket, and include a specific update on their progress towards implementing static FI;
  - Order Xcel to include updated information on Flexible Interconnection in its 2027 IDP;

- Require Xcel to incorporate and otherwise address discussions and learnings from the DGWG process in its 2026 and 2027 filing; and,
- Require Xcel to review materials from Ameren and CHARGED, who have worked extensively on Flexible Interconnection and present key considerations. We recommend that Xcel incorporate these considerations into its program design and address these materials in its 2026 report and 2027 IDP.

- For future Proactive Upgrade Proposals, require Xcel to conduct an integrated, coordinated analysis of alternatives, including use of Flexible Interconnection, potentially in tandem with DSRUP.

- Order Xcel to rectify PNL deficiencies during the current IDP cycle. Specifically, ELPC/CEF/VS recommend that the Commission:
  - Order Xcel to file, by December 31, 2026, an interim update that: (1) demonstrates that it has given due consideration to the alternative PNL methodologies presented by stakeholders and substantively evaluates those methodologies; (2) provides specific details about the seasonal dependability factors, including the percentages it plans to use and which months would apply to each season; and (3) analyzes the impacts of those seasonal dependability factors; and,
  - Order Xcel to address its implementation of these topics in its 2027 IDP.

- Direct Xcel to engage stakeholders regarding modifications to its risk analysis and planning methodologies to improve cost-effectiveness while still maintaining safety and reliability, including consideration of: (1) application of CMO calculation to planning for N-1 scenarios; and (2) use of emergency ratings in planning for N-1 conditions. In its next IDP, Xcel should discuss its stakeholder engagement efforts and explain any changes it has made in response and/or why it has not incorporated stakeholder recommendations.

- Require Xcel to integrate equity considerations explicitly and transparently into its targeted underground program from the start to ensure that communities facing disparities in reliability appropriately benefit in a timely manner. In addition, the Commission should require the Company to explore using the ICE 2.0 Calculator from Lawrence Berkeley National Laboratory to inform this integration. To the extent the ongoing third-party study provides additional insights, Xcel should incorporate those, as well; however, there is no reason to delay consideration of equity when the Company has already identified disparities in reliability and targeted undergrounding as a solution.

- Require Xcel to report annually on its targeted undergrounding program. We suggest these reports should include the following data: number of undergrounding projects; number of projects in Environmental Justice areas; actual undergrounding project costs; drivers for projects (engineering, equity, other); and description of community engagement efforts.

- Require Xcel to continue to describe its DERMS plans, use cases, and stakeholder engagement in its Integrated Distribution Plans.

- Require Xcel, before filing its next IDP on November 1, 2027, to:
  - Establish equity-informed prioritization criteria for distribution investments. The Commission should require Xcel to develop and implement systematic criteria that prioritize investments addressing documented service disparities. The Company should weight these criteria appropriately in its distribution project scoring and prioritization processes.
  - Integrate equity requirements into the IDP process. The Commission should require Xcel to demonstrate in its IDP filings how it will systematically and transparently incorporate equity considerations into distribution planning and investments. We note that this may mean that the Company would prioritize system upgrades in communities, that would bear disproportionately greater impacts from outages, such as spoiled food or medicine, including low-income and otherwise vulnerable communities.
  - Implement transparent reporting on equity outcomes. The Commission should require Xcel to report on reliability improvements and infrastructure investments by environmental justice area, income level, and racial composition in its Safety, Reliability, and Service Quality annual reports, just as the Company reports on reliability or other dimensions of utility performance. This reporting should demonstrate whether rate-funded investments are systematically addressing documented disparities or perpetuating inequitable service patterns.

    Xcel should discuss its implementation of these requirements in its 2027 IDP.

- Require Xcel to explore use of the Interruption Cost Estimate 2.0 methodology from Lawrence Berkeley National Laboratory to identify and prioritize investments in low-income and other vulnerable communities.

- Require Xcel to provide a supplementary filing in this docket by December 31, 2026 that includes: (1) a detailed, Minnesota-specific wildfire risk assessment; and (2) evaluates wildfire risk both (a) in relation to Xcel's other jurisdictions, such as Colorado and Texas, where urgent mitigation investments may be more pressing, and (b) relative to other safety and reliability risks in Minnesota's distribution system. This supplementary filing should also include discussion of how these analyses support Xcel's specific investment proposals.

Respectfully submitted,

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Date: February 26, 2026

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Xcel Energy		Information Request No.	19
Docket No.:	E002/M-25-142		
Response To:	Fresh Energy		
Requestor:	Will Mulhern		
Date Received:	December 19, 2025		

Question:
Reference: 2025 IDP, Chapter 7, p. 19.

Xcel states "… we are currently unable to report distribution system locations for energy efficiency and demand response (DR) programs due to the nature of our DSM offerings … Additionally, our DSM program systems are separate from those used for distribution system planning and operations." Please explain if and how Xcel's implementation of an Aggregator DERMS will address these issues.

Response:
Currently, the Company has not scoped any integrations between the Aggregator DERMS platform, energy efficiency reporting systems, and distribution system planning tools. However, it is important to note that when customers participate in DSM programs, the resulting impacts—such as changes in load—are visible to the distribution planning team through our SCADA system. These effects are therefore inherently incorporated into our overall planning process, even though the DSM program systems themselves operate separately from distribution planning tools. Additionally, the Aggregator DERMS platform is intended to provide operational control across multiple demand response offerings.

Preparer:	Brenda McDermott
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Department:	Integrated System Planning
Telephone:	763-493-1513
Date:	January 14, 2026

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

Xcel Energy		Information Request No.	86
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: Flexible Interconnection and Reactive Upgrade Framework
Reference(s): IDP Chapter 7

Please describe how Xcel plans to integrate flexible interconnection into the Distribution System Reactive
Upgrades Process (DSRUP), described in Docket No. E002, E015, E017/CI-24-288. For example, if one developer opts for flexible interconnection, but then a second developer opts for the DSRUP on the same system, will the flexible interconnection developer have its flexible interconnection agreement canceled in order to then require a DSRUP cost share payment instead?

Response:
Flexible Interconnection and the Distribution System Reactive Upgrades Process (DSRUP) are being proposed as separate and mutually exclusive interconnection pathways. A customer choosing Flexible Interconnection would be proceeding under a framework that relies on operational limits or curtailment, while a customer selecting DSRUP would be participating in a cost-sharing mechanism for distribution upgrades. Because these pathways serve different purposes, the Company does not intend for a customer to move from one pathway into the other solely because another developer later selects a different option.

At this time, however, neither the DSRUP framework nor a flexible interconnection program has been approved or fully designed. The Commission has not yet established the final rules that would govern how these programs interact, and the Company has not developed the detailed implementation procedures that would be required to administer both pathways.

For these reasons, the Company cannot provide a definitive answer to the hypothetical scenario described—such as whether a flexible interconnection agreement would be canceled if another developer later opts into DSRUP on the same system. Any such outcome would depend on future Commission decisions, final

program design, and the governing tariffs and contractual terms adopted at the time. Because those elements are not yet established, any assumptions about how the two frameworks might interact would be premature and outside the scope of the current proposal.

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Xcel Energy		Information Request No.	89
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: Distribution Budget Growth
Reference(s): IDP Attachment L

The following budget data is provided by Xcel in Attachment L, with the difference columns calculated by the Department:

IDP Budget Category	2020-2021 Avg (Millions)	2026-2030 Avg (Millions)	Difference (Millions)	Difference (%)
Age-Related Replacements and Asset Renewal	$99.7	$389.7	$290.1	291.0%
System Expansion or Upgrades for Capacity	$39.7	$238.7	$198.9	500.8%
System Expansion or Upgrades for Reliability and Power Quality	$28.8	$90.8	$62.0	215.0%

Please explain:

1. The top five reasons why each of the budget categories listed above have increased by the listed percentages. Make sure that five reasons are listed for each of the three budget categories.
    a. Please indicate an estimated percentage contribution to total categorical budget growth of each of the five reasons. The estimate does not need to be exact.
2. Whether Xcel expects each of these budget categories to shrink, stay the same, or grow in its 2031-2035 budget.

Response:

1. The Company objects to providing estimated percentage contributions for each reason of budget growth. Attachment L does not contain a cost breakdown by driver, and the Company's forecasting tools do not track budget growth at the level of attribution requested. Any attempt to retroactively assign percentage weights would require speculative assumptions that are not supported by underlying data, would be unduly burdensome to develop outside the normal planning process, and could mislead the record with figures that imply precision we do not have.

Subject to this objection, the Company provides the requested top reasons for growth in each category without percentage allocations.

a. Age-Related Replacements and Asset Renewal
    - Infrastructure aging - A substantial portion of the existing distribution assets are reaching or exceeding the useful life, requiring accelerated replacement to maintain reliability and safety.
    - Wildfire Mitigation - This investment reduces the risk of severe wildfires by improving early detection, removing potential fuel sources through enhanced vegetation management, and strengthening infrastructure to withstand extreme conditions.
    - Material and labor cost inflation - Significant increases in material costs (steel, copper) and labor rates have driven up the overall cost of replacement projects.
    - Technology modernization - Replacement projects increasingly incorporate advanced technologies (smart sensors, automation) to improve system performance, adding to overall costs.

b. System Expansion or Upgrades for Capacity
    - Load growth from electrification.
    - Population and economic growth - Expansion in service territory and new developments necessitate additional feeders, substations, and capacity enhancements, including revitalization of some areas.
    - Mitigating existing capacity risks.
    - Material and labor cost inflation - Significant increases in material costs (steel, copper) and labor rates have driven up the overall cost of replacement projects.

c. System Expansion or Upgrades for Reliability and Power Quality
    - Higher reliability standards - Regulatory and customer expectations for fewer outages and improved service quality require targeted reliability investments that maintain or improve the reliability and quality of electric service.
    - Environmental risks - Increased frequency of severe weather events necessitates hardening measures such as underground and reinforced structures.
    - Advanced monitoring and automation - Deployment of smart grid technologies (automated switches, sensors) to quickly identify and isolate faults and restore service adds cost.
    - Material and labor cost inflation - Significant increases in material costs (steel, copper) and labor rates have driven up the overall cost of replacement projects.

2. Looking ahead to 2031–2035, Xcel expects all three budget categories to continue growing.

a. **Age-Related Replacements & Asset Renewal**: Grow. Ongoing asset aging, test-and-treat outcomes, modernization embedded in renewals, and compliance needs are expected to keep upward pressure on this category.
b. **System Expansion/Upgrades for Capacity**: Grow. Electrification, economic development, DER interconnections, and mitigation of emerging constraints are expected to continue.
c. **System Expansion/Upgrades for Reliability & Power Quality**: Grow. Reliability expectations, resilience/hardening against severe weather, and continued automation/monitoring deployments are expected to increase needs.

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Xcel Energy		Information Request No.	26
Docket No.:	E002/M-25-142		
Response To:	Minnesota Department of Commerce		
Requestor:	Ari Zwick		
Date Received:	November 25, 2025		

Question:
Topic: LoadSEER Forecast Accuracy
Reference(s): Proactive Upgrade Proposal

Please present an analysis of Xcel's 2023 LoadSEER forecast accuracy for 2023 and 2024 actuals for peak load and any available DER adoption data. Please ensure that data for the MDT077 project is included in this analysis.

Response:
In the 2025 Integrated Distribution Plan (IDP) also filed in Docket No. E002/M-25-142, we evaluated the accuracy of the 2023 LoadSEER forecast by comparing it to actual peak load data for both 2023 and 2024. In Chapter 1 of the 2025 IDP on pg. 77, Table 1-11 in the IDP summarizes these results as an aggregation of non-coincident feeder circuit peak loads, which includes the MDT077 feeder. This table also incorporates available DER adoption data relevant to the analysis. We provide this table below.

Table 1-11
Comparison of 2023 IDP Forecast to Actuals
Aggregated Distribution Feeder Peak Load (MW)- MDT077 MN

Aggregate Distribution Feeder Peak Load- MN (MW)		
	2023	**2024**
Historic Actuals	8,205	7,996
2023 IDP Low Native	8,702	8,806
2023 IDP Med Native	8,708	8,819
2023 IDP High Native	8,715	8,837

As we describe further in the 2025 IDP, the results shown in Table 1-11 do not show the historic actuals matching the forecast. This is an expected outcome that can happen for multiple reasons, including:

- Weather impacts – cooler weather during the summer generally results in lower peak loads.

- New customers not coming online in the year expected
- New customer loads coming in less than the forecasted peak demand value
- Load switching – While we don't usually record abnormal peak load values that occur due to switching on the distribution system, in some cases it is difficult for engineers to distinguish between a switching event and permanent changes in a feeder's loading when reviewing historical loading data.
- Changes to aggregate distribution feeder peaks – While there are changes to the aggregate peaks, this is not particularly important for distribution planning purposes. We need to plan for all assets on the system annually, including each individual feeder and each substation bank (approximately 1,500 assets).

The distribution system is constantly changing, and peak demand values can fluctuate yearly. The Company utilizes forecast data to inform its distribution system planning, ensuring infrastructure is designed to reliably serve the maximum load that could reasonably be encountered. While actual peak loads in a given year may fall below forecasted values, such deviations do not inherently indicate inaccuracies in the forecast. For example, cooler-than-average summer weather may suppress peak demand, but similar conditions to prior warmer years could result in those historic peaks being met or exceeded again. Additionally, it is not necessarily appropriate to rely solely on metrics such as average summer temperature, maximum temperature, or cooling degree days to determine whether a year's peak load should be considered indicative of typical system demand under design conditions. While such metrics may provide insight into overall energy consumption, peak load events are driven by a confluence of factors, including weather, customer behavior, energy prices, and broader economic conditions, that must be considered holistically in the planning process.

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Xcel Energy		Information Request No.	8
Docket No.:	E002/M-25-142		
Response To:	Fresh Energy		
Requestor:	Will Mulhern		
Date Received:	December 19, 2025		

Question:
Reference: 2025 IDP, Chapter 2, p. 4.

Please explain how Xcel identifies, prioritizes, and determines budgets for routine asset health projects each year (i.e., replacement of cable, poles, substation equipment).

Response:
The Company employs a structured process to manage routine asset health investments, including cable, pole, and substation equipment replacements. Assets are identified through condition assessments, age, failure history, and inspection data, with emergent needs such as storm damage incorporated into planning. Projects are prioritized based on reliability, safety, and system performance, with key programs including cable and pole replacement, substation renewals, and discrete rebuilds. Annual budgets are determined using historical spending trends, forecasted failure rates, and lifecycle analysis, and are adjusted for emergent work and economic conditions. These investments are strategically aligned to maintain reliability, enhance grid resilience, and support long-term lifecycle management.

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Xcel Energy		Information Request No.	9
Docket No.:	E002/M-25-142		
Response To:	Fresh Energy		
Requestor:	Will Mulhern		
Date Received:	December 19, 2025		

Question:
Reference: 2025 IDP, Chapter 2, p. 4.

Please explain how Xcel identifies, prioritizes, and determines budgets for discrete asset health projects each year.

Response:
The Company employs a structured process to identify, prioritize, and budget for discrete asset health projects, which are typically large, multi-month efforts exceeding $300,000. These projects are identified through comprehensive condition and risk assessments, considering factors such as asset age, failure history, obsolescence, and reliability performance. Prioritization is based on system reliability, safety, and strategic alignment with long-term grid resilience and clean energy objectives. Budgets for discrete projects are determined using detailed cost estimates and lifecycle analysis, with allocations phased across multiple years to reflect project scope and timing.

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Xcel Energy		Information Request No.	13
Docket No.:	E002/M-25-142		
Response To:	Fresh Energy		
Requestor:	Will Mulhern		
Date Received:	December 19, 2025		

Question:
Reference: 2025 IDP, Chapter 2, p. 34.

Please explain how Xcel identifies, prioritizes, and determines budgets for asset replacement in the Substation Renewal program.

Response:
The Company identifies assets for replacement in the Substation Renewal program by evaluating numerous factors including age, reliability history, field inspection and testing results, maintenance history and costs, and known manufacturing issues. The asset replacement projects are prioritized and ranked based on the same factors; for example, the oldest equipment is prioritized first, and so on. We determine budgets by developing cost estimates for proposed work and comparing these projects against other system needs during the annual budgeting process to select which projects move forward.

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Xcel Energy		Information Request No.	28
Docket No.:	E002/M-25-142		
Response To:	Fresh Energy		
Requestor:	Will Mulhern		
Date Received:	February 2, 2026		

Question:
Reference: 2025 IDP, Attachment E

Please explain why projects with risk scores less than 1.0 addressing 2026 forecasted loading significantly below 75% (e.g., mitigation #s E147.011656, E147.013373, E150.022705, etc.) are included in the budget.

Response:
The Company does not use a single numerical cutoff, such as a risk score below 1.0 or a specific forecasted loading threshold, to determine whether a mitigation project is included in the distribution budget. As explained in the 2025 Integrated Distribution Plan ("IDP"), risk scores are used as a comparative tool to evaluate and prioritize mitigation options, rather than as a pass/fail screening criterion.

Projects with lower risk scores or with 2026 forecasted loading below 75 percent may still be budgeted for several reasons:

- Mitigations often address multiple risks, not solely forecasted loading on a single device. The loading shown in Attachment E may appear low, even though the project resolves broader system constraints or future emerging needs.
- Some projects are driven by N-1 contingency risks, which do not show up in the N-0 loading values presented in Attachment E. A device may appear lightly loaded under normal conditions but still require mitigation to ensure the system can withstand a contingency event.
- Budget decisions incorporate other system priorities—including reliability, resiliency, asset health, and long-term planning needs—so capacity loading alone does not dictate whether a project is included. For this reason, the risk score is not directly comparable to a complete cost benefit analysis, for which 1.0 is the threshold for the total benefits outweighing the costs. It is a metric used to compare the anticipated capacity-derived reliability benefits of different projects; a risk score less than 1.0 does not mean that a project should not be funded.

Accordingly, mitigations such as E147.011656, E147.013373, and E150.022705 are included because they address system needs beyond the single-year loading metric shown in Attachment E.

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