STATE OF MINNESOTA
PUBLIC UTILITIES COMMISSION

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March 1, 2024

In the Matter of Xcel Energy's 2023 Integrated Distribution Plan	**Docket No. E002/M-23-452**

INITIAL COMMENTS OF FRESH ENERGY

Fresh Energy submits these Initial Comments in response to the Commission's November 17, 2023, *Notice of Comment Period* ("Notice") regarding Northern States Power Company dba Xcel Energy's ("Xcel") 2023 Integrated Distribution Plan ("IDP"). The focus of these comments is *Notice* topics 14 through 24. Fresh Energy is also filing separate comments today as part of the Clean Energy Groups, focused on electric vehicles and distribution grid upgrades.

I. INTRODUCTION

On November 1, 2023, Xcel Energy filed its 2023 IDP pursuant to the Commission's July 26, 2022 Order in Xcel's most recent IDP, Docket No. E002/M-21-694.

A. Scope of comments

Fresh Energy believes Xcel has produced a strong fourth IDP that meaningfully builds on past plans and Commission orders. Fresh Energy continues to strongly support the Commission's work to facilitate comprehensive and transparent distribution planning to enhance reliability, affordability, efficiency, customer engagement, and information accessibility. As Minnesota works to meet ambitious clean energy policies by the end of this decade, IDPs are an essential tool for planning and information sharing. With this IDP, Xcel has provided voluminous information about its distribution system, planning processes, risk identification and mitigation, but has also laid the foundation for several important policy discussions including:

- How will load growth from a changing economy, distributed energy resources and electrification impact distribution spending over the next several decades?

- How do we plan for, and pay for, this expansion while prioritizing affordability, especially for under-resourced customers?
- How do we maximize system efficiency and the value of new grid technologies to keep spending reasonable while securing benefits from grid modernization?

Fresh Energy's Initial Comments address the following main IDP issues:

- Xcel's Non-Wires Alternatives analysis
- Integrated Volt-Var Optimization
- Xcel's planned capital budget
- LoadSEER forecasting results and methodology
- Planned Net Load and 15% Dependability Factor
- Proactive upgrades for electrification and DER growth
- Cost-benefit analyses for certain discretionary capital investments

B. Primary Recommendations

Fresh Energy's recommendations to the Commission are:

- Accept Xcel's 2023 IDP as in compliance with IDP reporting requirements.
- Require Xcel to reevaluate Integrated Volt-Var Optimization ("IVVO") to identify feeders for which IVVO is cost-effective, using the new Minnesota Test and updated assumptions informed by Public Service Company of Colorado's experience with IVVO and the Company's forecasts for electric vehicle (EV) adoption, building electrification, and distributed generation adoption.
- Direct Xcel to develop a commercial electrification forecast, as well as a more robust residential electrification forecast for its next IDP. These electrification forecasts should include low, medium, and high levels, reflecting various levels of adoption and levels of participation in load-shaping programs.
- Discontinue IDP Requirement 3.A.9.

Fresh Energy also requests that Xcel address a number of issues in its Reply Comments, as discussed further below. These include the following:

- In reference to Non-Wires Alternatives ("NWA"):
    - Based on Public Service Company of Colorado's 2023 experience, what changes does the Company plan to make to its NWA process to increase the likelihood of a successful solicitation?
    - Has Xcel confirmed with potential NWA developers that they would be willing to install DER at their own cost, with Xcel contributing only the "ARR split"?
    - Which other utilities have offered compensation only in the form of an "ARR split" in successful NWA solicitations?
    - What specific other "use cases" does Xcel envision NWAs could provide when there is no load reduction requirement?
- In reference to IVVO:

    - Please provide examples as to how responsive specific end uses (electrification of transportation, water heating, building HVAC, and heat pumps, etc.) are to IVVO and how this responsiveness may impact IVVO benefits.
    - Has the company investigated how IVVO and/or CVR can help to manage over-voltage issues in areas with high DER penetration? What were the results of this investigation?
- Regarding the 5-year capital budget:
    - Please address why a system-wide change in mitigation thresholds is more reasonable, for the purposes of planning for or accommodating customer electrification and EV adoption, than incorporating electrification and EV forecasts into Xcel's Budget Plan scenario.
    - Please verify that Fresh Energy's understanding and analysis of risk thresholds and risk counts reflected in Table 2 is correct. If it is correct, please explain 1) why the number of risks has decreased in Xcel's current IDP compared to its 2021 IDP; and 2) why System Expansion or Upgrades for Capacity expenditures increase by 323% in 2024-2028 compared to 2019-2023 if the number of risks is decreasing.
- Regarding LoadSEER Forecasting:
    - Explain if Xcel has considered using 576-hour time series in LoadSEER, and if doing so would facilitate the incorporation of LoadSEER results into the Company's capital investment plans or sensitivities.
    - Please explain if Xcel could perform a sensitivity analysis on the relevant capital expenditure category (e.g., System Expansion or Upgrades for Capacity) using the IDP Low, Medium, or High scenario(s).
    - Please explain how Xcel could assess the geographic and temporal accuracy of LoadSEER forecasts (for example, by comparing forecasts to actual adoption patterns), and how the Company would recommend evaluating forecast accuracy.
    - Please discuss whether LoadSEER forecasts for solar, storage, EVs, and home electrification (whether in units or in *rate* of adoption) could be displayed in map form, and whether it would be feasible to do this on a census-tract level.
- In reference to Planned Net Load ("PNL") and 15% Dependability Factor
    - Does Xcel agree with Fresh Energy's analysis and conclusions summarized below for the PNL example feeder provided by Xcel on 2/14/24? If not, please explain why.
    - Does Xcel agree that only considering 0.6% of nameplate capacity as dependable PV is overly conservative? If not, please explain why.
    - In the PNL example, please explain why Xcel is using values for native and net peak load from different hours on different days.
    - In the PNL example, please explain why Xcel is using a value for net peak load during an hour where solar production is zero.
    - Please explain why Xcel is proposing to apply a 15% dependability factor to the PV generation impact and not the total nameplate capacity of PV generation.
    - Please explain why Xcel is deriving the dependability factor from average winter PV output instead of average summer output, when the majority of Xcel's feeders peak in the summer months.

- Regarding Potential Cost Sharing and/or Proactive Upgrades:
    - Please describe how grid upgrade costs are currently allocated today for: residential level 1 and 2 EV chargers, commercial level 1 and 2 EV chargers, DC fast chargers, residential beneficial electrification, commercial beneficial electrification, and distributed generation and storage projects.
- Please confirm that the Company will work with stakeholders in 2024 to develop a cost-benefit analysis methodology for six categories of discretionary Asset Health & Reliability expenditures (totaling $1.26 billion from 2024-2028) to demonstrate that customer benefits exceed customer costs.
- Please address our recommendations that Xcel's DSM action plan prioritize a) near-term (2024-25) expansion of behavioral, price-based, and pre-emergency demand response programs, and b) medium-term (2026-28) development of programs to utilize locational DSM dispatch capabilities.

II. FRESH ENERGY'S ASSESSMENT OF XCEL'S 2023 IDP

Fresh Energy believes Xcel has put forward a strong fourth IDP and has made good progress in this plan toward several policy objectives the Commission and legislature have identified, especially those related to planning proactively for DER integration and beneficial electrification. Fresh Energy also appreciates Xcel's responsiveness and willingness to clarify some of the more technical aspects of the IDP. In addition to providing responses to formal information requests, Xcel hosted three calls in December and January to allow Fresh Energy and our expert Curt Volkmann, to discuss and clarify several technical issues with Xcel engineers and planning staff.

These Initial Comments reflect Fresh Energy's current understanding of Xcel's IDP and request further clarification in Xcel's March 22, 2024, Reply Comments. Fresh Energy expects to provide more specific recommendations for the Commission in its April 12, 2024, Reply Comments.

Fresh Energy's initial comments on Notice Topics 14-24 are the following:

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

Fresh Energy recommends that the Commission accept Xcel's 2023 IDP.

15. Did Xcel Energy adequately address the Commission's IDP filing requirements and prior Orders, as outlined in Attachment A to this notice? Is additional information necessary for improved clarity?

Fresh Energy believes that Xcel has adequately addressed the Commission's IDP filing requirements.

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

a. Non-Wires Alternative Analysis

Xcel has identified three projects as viable candidates for potentially cost-effective Non-Wires Alternatives or NWAs. All three projects address capacity deficiencies, have a project cost greater than $2 million, and a required in-service date in 2028. Xcel provides detailed descriptions of each project's load reduction requirements, including available load relief from existing demand-response and solar on each feeder.[1] Xcel assumes that the load reduction requirement is only needed during weekdays from June through September.

To minimize the amount Xcel would pay for an NWA solution (and to increase the NWA's cost-effectiveness from Xcel's perspective), the Company is intending to compensate NWA developers a pro-rated amount reflecting only the DER output used to address the hours of the load reduction requirement (called the Avoided Revenue Requirement or ARR split). Xcel explains, "The ARR split represents the pro-rated NWA costs and stacked values that are proportional to the contribution of the DER to solving the risks."[2]

Xcel acknowledges that the "actual, total cost to install the DER would be considerably higher," and assumes that "the owner of the DER asset would be willing to install the DER at their own cost with the Company contributing only the (ARR split)."[3] Xcel further assumes that an "NWA solution could potentially be used by an NWA developer for other use cases during times when there is no load reduction requirement."[4]

While Fresh Energy agrees that, in theory, a DER project selected as an NWA could also be a participant in another Xcel Energy program/tariff that provides revenue or reduces costs for the DER, it is unclear to us whether this would be feasible in practice.

Fresh Energy also understands that Public Service Company of Colorado ("PSCo") conducted an unsuccessful NWA solicitation in 2023,[5] receiving zero bids, and requested its consultant to conduct a review of the NWA process and recommend potential changes for improvement.[6]

Fresh Energy asks that Xcel, in its Reply Comments, respond to the following:

- Based on PSCo's 2023 experience, what changes does the Company plan to make to its NWA process to increase the likelihood of a successful solicitation?
- Has Xcel confirmed with potential NWA developers that they would be willing to install DER at their own cost, with Xcel contributing only the "ARR split"?

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[1] Xcel 2023 IDP, Appendix F, pp. 31-41.
[2] *Id.*, p. 16.
[3] *Id.*, pp. 24-25.
[4] *Id.*, p. 15.
[5] https://co.my.xcelenergy.com/s/renewable/developers/non-wires-alternative-rfp
[6] DNV, *Xcel Energy NWA Independent Evaluator Recommendations for NWA Process Improvements*, September 27, 2023, https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=1006427&p_session_id=

- Which other utilities have offered compensation only in the form of an "ARR split" in successful NWA solicitations?
- What specific other "use cases" does Xcel envision NWAs could provide when there is no load reduction requirement?

b. Grid modernization plans, including but not limited to a Distributed Energy Resource Management System (DERMS), Virtual Power Plants (VPP), Integrated Volt-Var Optimization (IVVO), and Distributed Intelligence (DI)

Fresh Energy believes that DERMS, VPP and DI are grid modernization solutions that can provide customer value and advance the clean energy transition, and that all three are important for Xcel to continue pursuing in parallel with development of programs that utilize these technologies to provide customer benefits. We do not have more detailed comments on these technologies at this time. Fresh Energy discusses IVVO below.

Xcel states that it faces "the monumental challenge of expanding the distribution system to support the increased utilization and demand for electrification of homes, buildings, and transportation," and expects that "the feeder peak load of the distribution system will triple in size over the next 30 years … (including) new customer loads, distributed generation and the impact of demand response and energy efficiency."[7]

To address such a monumental challenge while minimizing costs to its customers, Fresh Energy expects that Xcel will need to deploy all cost-effective measures to reduce peak demand and energy consumption. This includes IVVO (as well as additional load flexibility measures, discussed more below).

Instead, Xcel has concluded that IVVO is not in the public interest. The Company explains, "The energy savings we assumed at the time of our (2019 IVVO) certification request did not account for declining benefits over time as customers adopt more energy efficient and constant power devices that do not have the same energy savings benefits when operating at lower voltages," and "the benefits we estimated from IVVO are lower now than they were in 2019."[8] However, in response to Fresh Energy information requests, Xcel acknowledges that it has not quantified any decrease in IVVO benefits since 2019, has not developed updated costs for IVVO deployment, and has not conducted an updated evaluation of IVVO cost-effectiveness.[9]

In contrast to Xcel's position on IVVO for its NSP service area, PSCo includes IVVO in its energy efficiency portfolio, delivering 330,000 MWh annually of energy savings and 44 MW of demand

[7] Xcel 2023 IDP, p. 2.
[8] Xcel 2023 IDP, Appendix B1, pp. 30-31.
[9] Xcel responses to Fresh Energy IRs 29, 30 and 31.

reduction.[10] Fresh Energy also understands that Illinois utilities Ameren and Commonwealth Edison include IVVO as a cost-effective energy efficiency portfolio measure.[11]

Fresh Energy believes that Xcel should reconsider the question of whether IVVO is in the public interest using updated assumptions and analysis. We recommend that the Commission require Xcel to re-evaluate IVVO for its NSP Minnesota service area using the new Minnesota Test[12] for cost-effectiveness. The revised cost-benefit analysis should identify the Company's feeders for which IVVO is cost-effective, using updated assumptions informed by PSCo's experience. In addition to a baseline CBA using the Company's budget forecasts, Fresh Energy recommends that Xcel complete a CBA using the forecasts identified in the "IDP High" scenario as detailed in Appendix A1, page 57, which would serve as a sensitivity to benchmark the range of net benefits from IVVO under different potential futures.. The Company should consult with interested stakeholders when updating its corporate forecasts for building electrification.

Fresh Energy also requests that in its reply comments, Xcel respond to the following:

- Please provide data on how responsive specific end uses are to IVVO and how this responsiveness may impact IVVO benefits. Please include common appliances such as: air conditioning, electric vehicle charging, electric water heating, electric resistance space heating, air source heat pumps, lighting, refrigeration, and electronic devices.
- Has the company investigated how IVVO can help to manage over-voltage issues in areas with high DER penetration? What were the results of this investigation?

c. Forecasted Distribution Budget

As shown in Table 1 below, Xcel is planning significant increases in capital expenditures across almost all IDP categories, resulting in more than ***$2 billion*** of increased capital spending from 2024-2028 compared to the previous five years.

[10] Colorado PUC Proceeding No. 16A-0588E, Public Service Company of Colorado AGIS CPCN Annual Forecast Report for 2024, p. 11.
[11] The Illinois utilities refer to IVVO as Voltage Optimization. See Ameren Illinois' 2023 Q3 Report, p. 22; Commonwealth Edison's 2023 Q4 Report, p. 13.
[12] See Decision, In the Matter of 2024-2026 Cost-Effectiveness Methodologies for Electric and Gas Investor-Owned Utilities, MN PUC Docket No. E, G999/CIP-23-46, March 31, 2023.

Table 1 - Xcel MN Capital Expenditures by IDP Category[13]

($ in millions)

	Actual 2019-2023	Planned 2024-2028	Increase (Decrease)	% Increase (Decrease)
Age-Related Replacements and Asset Renewal	$553	$1,135	$582	105%
System Expansion or Upgrades for Reliability and Power Quality	$171	$700	$529	310%
System Expansion or Upgrades for Capacity	$174	$734	$561	323%
Grid Modernization and Pilot Projects	$169	$253	$84	50%
New Customer Projects and New Revenue	$194	$246	$52	27%
Projects Related to Local (or Other) Government-Requirements	$169	$202	$33	19%
Electric Vehicle Programs	$20	$137	$118	594%
Metering	$33	$22	($10)	(32%)
Other	$229	$304	$75	33%
Total	$1,711	$3,734	$2,023	118%

The largest category of capital expenditures, and the category with the largest planned increase (in total dollars) over this period, is Age-Related Replacements and Asset Renewal.[14] Xcel states that this category (which is contained within the Asset Health and Reliability or "AH&R" category in Xcel's capital budgeting process) is not subject to a cost-benefit analysis ("CBA") or risk scoring, as such analysis "does not effectively capture the long-term value that a programmatic approach to asset health provides."[15] Xcel also states that these programs are "funded based on identified needs or risks outside of the budget risk scoring model."[16]

Xcel's planned **System Expansion or Upgrades for Reliability and Power Quality** expenditures (also contained within the AH&R category in Xcel's capital budgeting process) are also significantly increasing in the later years of the IDP, as shown in Figure 1 below.

[13] Xcel 2023 IDP, Appendix D, Attachment N. "Other" includes fleet purchases, communication equipment, corporate initiatives such as fiber buildout and cyber security, tools and equipment, and routine transformer purchases associated with new business and reconstruction work.

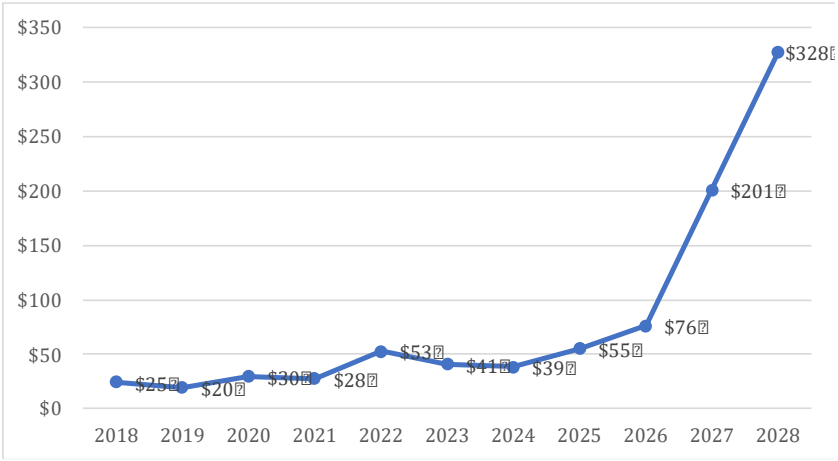
[14] Xcel IDP 2023, Appendix D, Attachment N. Includes Reactive Asset Health programs (pole replacement, routine rebuilds/conversions, restoration/failure reserves, reactive line programs, and SE Region Reliability Initiative reactive discrete projects) and Proactive Asset Health programs (substation renewal, line renewal, discrete projects including 4kV conversions).

[15] Xcel 2023 IDP, Attachment D, p. 2.

[16] *Id*.

Figure 1 – System Expansion/Upgrades for Reliability/Power Quality[17]

($ in millions)



In response to a Fresh Energy information request seeking an explanation for the increase, Xcel stated,

> "The increase in these out years can be attributed to our need for system hardening and resiliency. While we do not yet know how these specific dollars will be spent, we do know we have a need to address and are considering a variety of options including a potential for a more significant undergrounding program. While we do not yet have these details, we continue to discuss and study internally and will bring forward more concrete proposals and budgets in the future."[18]

As we explained in Xcel's most recent rate case proceeding,[19] Fresh Energy believes that a meaningful share of AH&R projects are discretionary, meaning that Xcel has flexibility to determine when, where, and how much to spend. The primary benefit of discretionary AH&R expenditures is improved reliability and resiliency, which Xcel can and has quantified for components of its AGIS initiative. As further explained in our comments responding to Notice Topic 19, Fresh Energy requests that, in its Reply Comments, Xcel confirm that it will work with stakeholders in 2024 to develop a cost-benefit analysis methodology for six categories of discretionary AH&R expenditures (totaling $1.26 billion from 2024-2028) to demonstrate that customer benefits exceed customer costs.

As shown in Table 1 above, Xcel's planned **System Expansion or Upgrades for Capacity** expenditures are also increasing significantly (by 323%) in 2024-2028 compared to the previous five years. Notably, these planned expenditures exclude the impacts from forecasted electric

[17] Xcel 2023 IDP, Appendix D, Attachment N.
[18] Xcel response to Fresh Energy IR 35.
[19] MN PUC Docket No. E-002/GR-21-630, Direct Testimony of Curt Volkmann, October 3,2022, pp. 4-7.

vehicle, building electrification, or distribution generation adoption modeled by Xcel's new advanced planning tool LoadSEER.[20] Xcel explains,

> "The Budget Plan scenario represents the distribution load forecast when only the corporate energy sales and demand forecast is included and is the forecast that is primarily used for planning projects in the Distribution five-year capital budget. The Budget Plan scenario is used for planning projects because it only contains load growth that is considered "known and expected" based on actual applications to add load that have been received, as well as known trends for new customer interconnections; this represents the minimum desired funding level for capacity work to meet immediate distribution system capacity needs."[21]

Fresh Energy agrees with Xcel that on net, incorporating these electrification and distribution generation forecasts is likely to increase the scale of infrastructure projects identified through its planning process (above the "Budget Plan scenario"). Planning for higher adoption scenarios raises important public interest questions around the responsibility to pay for upgrades, inter- and intra-class equities, and overall affordability – which Fresh Energy addresses in response to question #17 below.

Xcel has also made changes in its planning criteria, which contributed to the increase in planned spending. Specifically, Xcel has lowered its thresholds for triggering capacity mitigations, most notably establishing a new feeder loading limit of 75% of normal rating (previously 106% of normal rating). Xcel explains:

> "Planning Engineers identify potential solutions to provide necessary additional capacity to address the identified system deficiencies. We apply thresholds that risks must exceed before we develop a project to mitigate the risk. In 2022, Distribution Planning conducted a review of these thresholds, and implemented a change that will help prepare the distribution system for the rate of growth and changes in customer expectations that are expected to occur in the future … ***This change is a reduction in the thresholds from what have been used historically and will help improve the availability of the distribution system to interconnect new load, such as beneficial electrification or electric vehicles before overloads are experienced***. It will also improve our ability to continue reliably serving load under contingency and perform planned work on the distribution system without jeopardizing reliability."[22] (emphasis added)

The rationale Xcel provided for this change, as shown in the quote above, is to accommodate more electrification and to improve reliability and continuity of service during maintenance. Fresh Energy requests that Xcel address in reply comments why this approach (a system-wide capacity

[20] Xcel response to DOC IR 24(b).
[21] Xcel 2023 IDP, Appendix A1, p. 49.
[22] Xcel 2023 IDP, Appendix A1, pp. 80-81.

threshold change) is more reasonable than incorporating electrification forecasts into its Budget Plan scenario, for the purposes of planning for electrification. Xcel explains that these changes in risk thresholds contribute to the planned increase in spending, stating,

> "Our latest five-year budget – largely in 2026 and 2027 – reflects ***the necessary funding level to start to enable upgrades that will start to bring all Minnesota feeders within our established guideline of a 75% loading level*** … This overall budget is included in the System Expansion or Upgrades for Capacity IDP category; however, not all specific mitigations to reduce feeders to less than 75% loading have been identified."[23] (emphasis added)

In response to a DOC information request, Xcel confirms that it does not yet know the full cost increase associated with these changes in risk thresholds, stating "While we have begun evaluations of the cost implications, we are still refining our methodology for an accurate estimate."[24] Table 2 below summarizes Fresh Energy's understanding of Xcel's previous and current feeder and substation transformer loading thresholds for N-0 and N-1 risks.[25]

Table 2 – Xcel's Risk Thresholds and Risk Counts[26]

		2021 IDP		2023 IDP	
		Threshold	Risk Count	Threshold	Risk Count
Feeders	N-0 Risks	106% of normal rating	65	75% of normal rating (15kV), 50% of normal rating (25/35kV)	67
	N-1 Risks	3 MVA above normal rating	566	0 MVA above normal rating	540
Substation Transformers	N-0 Risks	106% of normal rating	20	100% of normal rating	13
	N-1 Risks	3 MVA above single-cycle rating	151	0 MVA above multi-cycle rating	177
		Total Risks	**802**		**797**

[23] Xcel 2023 IDP, Appendix D, p. 7.
[24] Xcel response to DOC IR 30(c).
[25] Xcel identifies anticipated capacity deficiencies or constraints that will potentially result in overloads during normal (also called "system intact" or N-0) and single contingency (N-1) operating conditions. Normal operation is the condition under which all electric infrastructure equipment is fully functional. Single contingency operation is the condition under which a single element (feeder or distribution substation transformer) is out of service. See Xcel 2023 IDP, Appendix A1, p. 2.
[26] Xcel 2021 IDP, Appendix A1, pp. 19-20; Xcel 2023 IDP, Appendix A1, p. 73 and p. 81, Table A1-16. Normal rating is the maximum allowed equipment loading under normal operation. Single-cycle rating is the allowed

Fresh Energy would have expected Xcel's lowering of risk thresholds to *increase* the number of identified risks in Xcel's current IDP compared to its 2021 IDP. However, as shown in Table 2, the number of identified risks has decreased slightly.

Fresh Energy requests that Xcel, in its Reply Comments, verify that our understanding and analysis reflected in Table 2 is correct. If it is correct, please explain 1) why the number of risks has decreased in Xcel's current IDP compared to its 2021 IDP; and 2) why System Expansion or Upgrades for Capacity expenditures are increasing by 323% in 2024-2028 compared to 2019-2023 if the number of risks is decreasing.

d. Initial LoadSEER forecasting results and methodology

Fresh Energy is pleased that, after the Commission certified the tool in the Company's 2019 IDP proceeding, Xcel has now started incorporating LoadSEER into its planning processes by illustrating long-term aggregated feeder peak load under its IDP Low, IDP Medium, and IDP High Scenarios. However, as explained above, Fresh Energy is concerned that Xcel is not yet using the LoadSEER results to inform its capital investment plans (e.g., through sensitivity analysis as a first step) and requests that the Company clarify its intentions in Reply Comments.

i. Potential for streamlining:

LoadSEER provides Xcel with enhanced planning capabilities, including the ability to develop 8,760-hour representations of feeder and substation transformer loading for each year of a 30-year forecast.[27] This means that the load shapes represent the hourly loading on feeder and substations throughout a full year. While this is a powerful modeling capability, it adds complexity and computational intensity to once-routine forecasting and planning processes.

Fresh Energy understands that several utilities, including Hawaiian Electric[28] and the California investor-owned utilities, have concluded that not all 8,760 hours matter for every distribution planning application. These utilities have adopted more manageable 576-hour time series[29] for load forecasting and hosting capacity analysis. Fresh Energy requests that Xcel, in its Reply Comments, explain if it has considered using 576-hour time series, and if doing so would accelerate the incorporation of LoadSEER results into the Company's Budget Plan scenario and capital investment plans.

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loading for a single 24-hour period under contingency operation. Mutli-cycle rating is the allowed loading for multiple 24-hour periods under contingency operation.

[27] Xcel 2023 IDP, Appendix A1, p. 57.

[28] See, for example, https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/working_groups/distribution_planning/20200602_dpwg_distribution_planning_methodology.pdf

[29] 2 days each month corresponding to peak/minimum days or weekdays/weekends - 2 x 24 x 12 = 576.

ii. Utilizing LoadSEER forecasts to inform capital investment plans:

Fresh Energy has long advocated that Xcel's distribution planning should incorporate a reasonable level of forecasted building electrification, EV adoption, adoption of on-site distributed generation, and demand flexibility.[30] However, as discussed in more detail in response to question #17 below, developing a distribution budget based on technology adoption forecasts, which have an inherent level of uncertainty, raises several important questions about prudency, cost-effectiveness, and equity.

With this IDP, Xcel has performed several sensitivities of its load forecast using LoadSEER to calculate the aggregate peak load on all distribution feeders and substation transformers under three main scenarios: IDP Low, IDP Medium, and IDP High.[31] Each of these three scenarios includes a forecast for EV adoption, beneficial electrification, front-of-meter solar, rooftop solar, and battery storage, which is higher than that used in the "Budget Plan scenario."[32] This is a very helpful development. Fresh Energy is pleased to see that each scenario aggregates forecasts from each technology, as the load shapes are in some cases complementary. We are also pleased to see that the EV load shape Xcel used in this scenario exercise was reflective of managed charging.[33]

While this analysis is very helpful for understanding the potential peak demand impacts of DER and electrification adoption, it does not quantify potential infrastructure needs or costs, even in the near term. Fresh Energy requests that in Reply Comments, Xcel discuss whether it could perform a sensitivity analysis on a relevant capital expenditure category (e.g., System Expansion or Upgrades for Capacity) using the IDP Low, Medium, or High scenario(s). The intention of such a sensitivity, or set of sensitivities, would be to provide transparency into a potential high-DER bookend, while the Budget Scenario provides a low-DER bookend. Ideally, a sensitivity analysis like this may also illuminate opportunities for efficiency or cost-savings.

iii. Beneficial Electrification Forecast:

Xcel notes that "the corporate level BE forecast for Minnesota is in its nascent stage and currently only represents residential water heat and residential space heat. Only one representative forecast scenario is available, and it corresponds to a high adoption case."[34] Within the residential building electrification sector, these two technologies are likely the most important to consider as they typically are a home's largest loads (aside from an electric vehicle, forecast separately). However, Xcel's beneficial electrification forecast currently lacks any commercial and industrial electrification (except a baseline level representing known projects included in the corporate demand forecast). Given the large-scale changes in commercial and industrial electricity demand now occurring, Fresh Energy recommends that Xcel prioritize development of a commercial electrification forecast, as well as a more robust low, medium, and high residential electrification forecast, for the next IDP. These electrification forecasts should adequately consider the demand management potential of

[30] Fresh Energy, Initial Comments, February 25, 2022, Docket No. E002/M-21-694, p. 5
[31] Xcel IDP, Appendix A1, p. 54-69.
[32] Xcel IDP, Appendix A1, p. 57
[33] Xcel IDP, Appendix A1, p. 56
[34] Xcel IDP, Appendix A1, p. 62

time of use rates or other load shaping programs, so that the LoadSEER forecast is built around meeting potential new customer needs efficiently.

iv. Forecast Accuracy:

Fresh Energy is excited about the potential for LoadSEER forecasting to improve the accuracy and transparency of distribution planning. Incorporating these locationally-specific forecasts into Xcel's planning process will help the company anticipate future system needs to accommodate the changes in technology and customer behavior that are underway and advanced by state policy.

It would be helpful, as Xcel moves forward, to provide stakeholders and the Commission with information assessing how accurate LoadSEER forecasts are over various time periods. This information is important as Xcel and the Commission consider potential additional uses of these forecasts, such as the role of LoadSEER forecasts in shaping distribution budgets. Fresh Energy requests that in reply comments, Xcel discuss methods by which geographic and temporal accuracy of these forecasts can be assessed (for example, by comparing to actual adoption patterns), and how the Company would recommend evaluating their accuracy.

e. Planned Net Load (PNL) methodology and 15% Dependability Factor

As Fresh Energy has explained in prior IDP comments, other utilities have well-established methodologies for incorporating the dependable load-reducing impact of distributed generation to quantify "net load" for use in load forecasts and distribution system planning,[35] The dependability factors used in these methodologies are typically expressed as a percentage of solar photovoltaic ("PV") nameplate capacity rating. Fresh Energy is pleased that Xcel has started to consider our prior recommendations, however, we are concerned that Xcel's initial Planned Net Load methodology is overly conservative and does not fully reflect the load-reducing impact from PV at the time of a feeder's peak load.

Xcel defines Planned Net Load ("PNL") as the calculated demand when the Company can assume that a certain percentage of PV generation is dependable to lower the peak.[36] Xcel examined five years (2016-2021) of recorded PV generation from its CSG program in Minnesota and concluded that average solar output from 8am-6pm ranges from 12-18% of nameplate capacity in the winter months and 37-41% of nameplate capacity in the summer months.[37]

Xcel is proposing an initial 15% dependability factor derived from the average winter output, stating that it "must use a conservative estimate to ensure system reliability," and that 15% "would be the most prudent value to use in an initial implementation of the PNL methodology."[38] However, the Company is proposing to apply its proposed 15% dependability factor to the PV generation *impact* (the difference between native and net load) and not the total *nameplate*

[35] MN PUC Docket No. 21-694: Fresh Energy Initial Comments, February 25, 2022, pp. 3-4.
[36] Xcel 2023 IDP, Appendix A1, p. 74.
[37] Xcel 2023 IDP, Appendix A1, Table A1-11, p. 78.
[38] Xcel 2023 IDP, Appendix A1, p. 77.

capacity of PV generation, even though the 15% figure was derived from output as a percentage of nameplate capacity.

Fresh Energy requested and received an example from the Company of how it calculates PNL[39] to better understand the implications of this proposed approach. The example feeder provided by Xcel has approximately 10 MW of PV nameplate capacity and a native peak load of 4.1 MW occurring at 5pm on July 19. The feeder's PV output at 5pm each day in July ranges from 454 kW to 3.7 MW with an average output of 1.9 MW.

Xcel's proposed PNL methodology, however, only deems 57 kW of the 10 MW of PV on the feeder (0.6%) as 'dependable' for reducing the feeder's peak load. To arrive at 0.6% of dependable PV, Xcel applied its proposed 15% dependability factor to the difference between a native peak load of 4,113 kW (which occurs at 5pm on July 19) and a net peak load of 3,733 kW (which occurs at 7pm on July 18, an hour where solar production is zero).

Fresh Energy requests that Xcel, in its Reply Comments, respond to the following:

- Does Xcel agree with Fresh Energy's analysis and conclusions summarized above for the PNL example feeder provided by Xcel on 2/14/24? If not, please explain why.
- Does Xcel agree that only considering 0.6% of nameplate capacity as dependable PV is overly conservative? If not, please explain why.
- In the PNL example, please explain why Xcel is using values for native and net peak load from different hours on different days.
- In the PNL example, please explain why Xcel is using a value for net peak load during an hour where solar production is zero.
- Please explain why Xcel is proposing to apply a 15% dependability factor to the PV generation impact and not the total nameplate capacity of PV generation.
- Please explain why Xcel is deriving the dependability factor from average winter PV output instead of average summer output, when the majority of Xcel's feeders peak in the summer months.

***17. What guidance should the Commission give on budgets and cost allocation for distribution system upgrades to accommodate distributed energy resources (DER), including but not limited* to:**

a. Solar sited with customer load
b. Solar sited in front of the meter
c. Energy storage devices
d. Electric Vehicles
e. Space heating, water heating, and other electrification use cases
f. Proactive grid upgrades in anticipation of future DER growth

[39]Excel spreadsheet "PNL Example.xlsx," received from Brian Monson on 2/14/24.

The issues of cost allocation and proactive upgrades are critical policy questions that Fresh Energy is pleased to see explicitly addressed in Xcel's IDP and the Commission's *Notice of Comment*. Many around the country are wrestling with this same set of questions, and there are a number of reports or analyses we can look to.[40] As these reports suggest, there is tension between least-cost planning and proactively building a distribution grid that will accommodate future DER and electrification. These issues, and the related issues of cost allocation of interconnection upgrades or contributions in aid of construction (CIAC), have begun to come up more regularly in Commission proceedings, stakeholder workshops, legislative venues, and elsewhere. This is a complex question which Fresh Energy believes could benefit from increased attention and structure.

In our view, it is helpful to consider more specific questions related to this topic in order to identify the gaps proactive upgrades may solve and how to best achieve an outcome that both ensures affordability and equity and advances the clean energy transition. Fresh Energy poses a number of such questions below. We are very interested in hearing from Xcel and stakeholders on these questions, if others disagree with or would add questions to this list, or if others have potential answers to these questions.

1. What are the problems we are trying to solve through proactive upgrades? In which customer classes and technology areas is adoption being hampered by the status quo / lack of proactive upgrades?
    a. Can these problems be solved through improving the efficiency and speed of the current process?
    b. Can these problems be solved by adjusting cost allocation for non-proactive upgrades? Would doing so be reasonable and equitable?
2. Would proactive upgrades improve operating efficiency, reduce truck rolls, or provide other benefits?
3. Are there no-regrets ways to plan for DER and electrification in the baseline load forecast, and therefore accomplish proactive upgrades via distribution planning?
    a. For which customer and technology segments do grid upgrades pay for themselves/ have a net revenue requirement *benefit* for ratepayers?
    b. How locationally and temporally accurate are Xcel's LoadSEER forecasts for each technology type? How accurate do they need to be to ensure a net beneficial result?
4. Are there customer and technology segments for which it may make sense to perform proactive upgrades that are paid back (on a prorated basis) over time by future interconnecting customers?

a. Cost Allocation as Distinct from Proactive Construction

We have observed that sometimes in conversations about grid upgrades for DER, the concepts of cost allocation for interconnection upgrades (whether for DG or electrification) and proactively planning for these upgrades are conflated. However, there are ways to combine shared costs with a

[40] See for example: Energy Systems Integration Group, Charging Ahead: Grid Planning for Vehicle Electrification, January 2024; Environmental Defense Fund, Building the Grid to Need, January 2024.

"reactive" (as opposed to proactive) upgrade process or to combine individually-allocated costs with proactive construction. Table 3 below illustrates in a simplified way, the manner in which these concepts can be combined into several possible policies. Of course, costs can also be shared among the group of participating customers only, or assigned to customer classes using various approaches. Additionally, there may be opportunities to accelerate "reactive construction" practices.

Table 3 – Cost Allocation and Proactive Construction Matrix

	Proactive Construction	**Reactive Construction**
Shared Costs	• Build distribution budgets around DER and electrification forecasts. • Assign incremental infrastructure costs via typical class cost allocation methods, e.g., in next rate case.	• Grid upgrades are made in response to individual customer requests. • Costs assigned via typical class cost allocation methods, e.g., in the next rate case.
Individually Allocated Costs	• Build distribution budgets around DER and electrification forecasts. • Individual customers, where appropriate, pay a fee to cover their share of the upgrade at time of interconnection.	• Grid upgrades are made in response to individual customer requests. • Individual customers, where appropriate, pay a fee to cover their share of the upgrade at time of interconnection.

Each of the four general policies described in Table 3 has different benefits and risks.

1. Shared-cost, proactive upgrades: Benefits customers adopting DER and electrification by reducing or eliminating wait time and cost of interconnection. Risks include deploying assets that are not used and useful if forecasts are not accurate, the potential for shifting costs of upgrades onto non-benefitting customers, and risk of inequitable investments.
2. Shared-cost, reactive upgrades: Benefits customers adopting DER and electrification by eliminating the cost of interconnection; benefits ratepayers by ensuring upgrades are used and useful. Risks include continued wait-times in the interconnection process, the potential for shifting costs of upgrades onto non-benefitting customers, and risk of inequitable investments.
3. Individually-paid, proactive upgrades: Benefits customers adopting DER and electrification by reducing or eliminating wait times for interconnection; benefits ratepayers by reducing the costs of upgrades via reimbursement over time. Risks include deploying assets that are not used and useful if forecasts are not accurate, and the potential for shifting costs of

upgrades onto non-benefitting customers if forecasts or reimbursement fees are not accurate.

4. Individually-paid, reactive upgrades: This is (for the most part) the model in place today. The primary benefit is ensuring upgrades are used and useful. Risks include wait time and interconnection costs for DER and electrification customers.

Some customer and technology segments may be good candidates for shared upgrade costs purely on a financial basis. For example, it is customary for some grid investments initiated by a single or small number of customers, for example a line extension to reach new customers, to be incorporated into base rates because the revenue anticipated as a result of the new customer(s) outweighs the cost – specifically, Xcel ratepayers generally cover extension and upgrade costs up to 3.5 times the anticipated annual revenue.[41] It is likely that several important categories of grid upgrades are or could be covered by this policy, such as those for residential electrification or upgrades for level 1 and 2 EV charging as long as charging is largely off-peak.

To gain a better understanding of whether certain customer and technology segments are good candidates for *shared* upgrade costs on a financial basis, Fresh Energy requests that in its Reply Comments, Xcel describe how grid upgrade costs are currently allocated today for: residential level 1 and 2 EV chargers, commercial level 1 and 2 EV chargers, DC fast chargers, residential beneficial electrification, commercial beneficial electrification, and distributed generation and storage projects. For each category, it would be helpful for Xcel to summarize who bears responsibility for the grid upgrade, in which circumstances, and how a contribution in aid of construction is calculated, if applicable.

There also may be technology and customer segments where shared costs are in the public interest for primarily policy reasons. For example, the Commission has approved a cost-sharing program for DG customers with projects up to 40 kW, where customers pay a flat fee and are exempt from common interconnection upgrade charges up to $15,000.[42] Under this program, income-qualified customers receive the $15,000 upgrade credit without paying the upfront fee. There has also been extensive discussion in Minnesota and across the country about a potential role for utility-owned EV charging infrastructure or rate-based make-ready infrastructure in areas that are currently underserved by charging networks.[43] Fresh Energy believes this may be a good role for utilities to play, filling a gap in the marketplace and helping to reduce barriers to electrification in underserved areas.

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[41] NSP Minnesota Electric Rate Book, Section 6, General Rules and Regulations, Sections 5.1 and 5.2 regarding Standard Installation and General Extension, Sheets 6-22 and 6-26. *"The Company will extend, enlarge, or change its distribution or other facilities for supplying electric service when the product of the three and one half (3.5) times the anticipated annual revenue, excluding the portion of the revenue representing fuel cost recovery from the sale of additional service to result there from is such as to justify the expenditure."*

[42] PUC Order Approving Implementation of Cost Sharing Plan as Modified, Docket No. E002/M-18-714, December 19, 2022.

[43] Fresh Energy has participated in these discussions, primarily as part of the Clean Energy Groups, through EV-focused dockets. See our comments in Dockets E002/M-18-643; E002/M-20-745; and E002/M-20-711.

b. Proactive Upgrades

When considering the role of *proactive* upgrades, Fresh Energy proposes four "pillars" that we would like to see these investments meet, which we believe will help to ensure they are in the public interest. As with the questions posted above, we are very interested to hear feedback from Xcel, the Department, and other stakeholders about these principles.

1. **Useful**: Proactive upgrades should be located in a relevant spot, needed, and useful.
2. **Timely**: Proactive upgrades should be reasonably certain of being useful within a specified period of time.
3. **Efficient**: Proactive upgrades that are recovered in base rates should be paired with programs that require or encourage efficient use of the grid (such as charging/discharging at preferable times to maximize utility of the infrastructure.)
4. **Equitable** – The costs and benefits of proactive upgrades should be equitably distributed, and any upgrades recovered in base rates should prioritize projects serving under-resourced customers or under-served areas of the system.

These pillars are largely rooted in recommendations made by others about this topic, especially a recent report from Energy Systems Integration Group (ESIG) on how to improve grid planning for electric vehicle adoption. This report makes four recommendations for doing so effectively and affordably: 1) improving the granularity of forecasting, 2) embracing smart charging, 3) making future-ready investments, and 4) proactive planning supplemented and guided by multi-stakeholder collaboration.[44] Fresh Energy has tried to broaden these concepts in a way that can be applied to proactive upgrades for any DER type, and added a pillar regarding equitable cost allocation which we find to be a critical component.

In this IDP, Xcel has proposed $190 million for proactive hosting capacity upgrades in 2025 through 2028. Xcel notes that this package is yet-undefined[45] and is currently a placeholder. From Fresh Energy's perspective, this package should not move forward until more specific plans are in place and information is available to enable the Commission to assess whether the investment is in the public interest. As the Company considers whether and how to move forward with these proposed investments, we encourage the Company to consider how potential investments meet the above principles.

Useful & Timely: The timing and location of some customer and technology segments are significantly more challenging to predict than others – for example, residential adoption rates are generally more predictable than "lumpier" investments like heavy-duty charging infrastructure or large-scale distributed generation projects. As noted in response to question 16.d. and in the list of questions Fresh Energy poses at the beginning of this section, more information from Xcel on the accuracy and precision of its current LoadSEER forecasts would be very helpful for stakeholders

[44] Energy Systems Integration Group, Charging Ahead: Grid Planning for Vehicle Electrification, January 2024, p. xii
[45] Xcel IDP, p. 15

when considering the potential for proactive upgrades. Similarly, information on how accurate the forecasts need to be to lead to prudent investments would be very helpful.

The ESIG report referenced above emphasizes the importance of data quality and multi-stakeholder engagement in proactive planning, suggesting that more collaboration with state departments of motor vehicles, regional transit authorities, fleet managers, shipping and delivery companies, and others is an essential component of effective proactive planning for vehicle electrification, particularly in the fleet or heavy-duty vehicle spaces. In addition to *proactive* planning, there is an opportunity for what ESIG calls "customer-collaborative planning," which can ease the interconnection process for customers while still using a "reactive" upgrade model that ensures upgrades are used and useful. Under these processes, customers engage with the utility earlier on and the utility works with customers to provide multiple interconnection options.

Efficient: Xcel's proposal to waive contribution in aid of construction (CIAC) payments for residential EV charging customers on managed or off-peak charging programs is an excellent example of this principle.[46] The ESIG study referenced above emphasizes the need to embrace smart charging in order to avoid over-building the grid for vehicle electrification.[47] For distributed generation, the parallel concept is export tariffs, or at minimum, export controls achieved through flexible interconnection. Fresh Energy understands that there is work underway at Xcel to implement export-limited interconnection, an important first step in this direction, and that flexible interconnection is planned for the latter part of this decade on Xcel's DER roadmap.[48] Fresh Energy would welcome feedback from Xcel and other stakeholders about whether and how programs similar to the residential EV CIAC waiver could be put in place for other customer segments or technologies. For example, would it be reasonable to waive or reduce CAIC for other electrifying customers that participate in time of use rates or peak-shaving programs?

Equitable: This pillar may be the most important one, and it informs the other three. The circumstances when proactive upgrades are in the public interest will generally be when the investment serves under-resourced or under-served customers, and/or investments whose costs are borne by customers benefitting from them. For myriad reasons, including higher likelihood of renting one's home to less savings available for home improvements, under-resourced residents are likely to be later adopters of personal EVs and electrification, unless efforts are made to counter this disparity. If proactive upgrades are planned based solely on forecasted adoption rates, those investments are likely to disproportionately serve higher-income areas.

To this end, it would be useful for the Commission and stakeholders to have a better understanding of the geographic distribution of forecasted DER and electrification adoption. Fresh Energy

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[46] Xcel proposed formalizing waiving CIAC for residential EV charging customers in its Appendix H: Transportation Electrification Plan to its 2023 IDP (pp 79-80), which Fresh Energy (as part of the Clean Energy Groups) supported in its December 20, 2023 initial comments.

[47] Energy Systems Integration Group, Charging Ahead: Grid Planning for Vehicle Electrification, January 2024, pp. 20-27

[48] Xcel IDP, Appendix E, p. 3

requests that in reply comments, Xcel discuss whether LoadSEER forecasts (in units or rate of adoption) for solar, storage, EVs, and home electrification could be displayed in map form, and whether it would be feasible to do this on a census-block group level.

c. Next Steps

At this stage, Fresh Energy believes that more record development is needed before determining how to move forward with proactive and/or cost-shared upgrades for DER and electrification. In addition to the specific requests we've made for Xcel above, Fresh Energy believes that more information on the following topics would be beneficial for this record:

- Existing research on the scale of grid upgrades (and their costs) that may be required by electrification and DER growth.
- Analysis on the appropriate allocation of those costs among customer groups.
- Examples of how other states and utilities are addressing this challenge.
- Information on how to improve locational and temporal forecasting accuracy, including the feasibility of data sharing from public and private entities.

The most productive way to accomplish this may be for Xcel and parties to continue dialogue and discovery through this docket and future IDPs. If the Commission feels more urgency on this matter, parties could also undertake an additional comment period on this specific topic, or engage in a Commission-led stakeholder workshop to bring more of these issue to light. Fresh Energy is very interested in reviewing other parties' comments on this topic and recommendations for how to move forward on this issue.

18. What decisions should the Commission make in the IDP to provide Xcel guidance in aligning distribution spending with forthcoming rate cases?

This question arose from Order Point 29 of the Commission's July 17, 2023 rate case Order in Docket No. E002/GR-21-630, which asked Xcel to discuss in this IDP: "ways for the IDP process to inform financial and cost recovery issues in rate cases, including but not limited to: a. The feasibility of conducting cost-benefit analyses for discretionary portions of the distribution budget; b. The decisions needed in the IDP to provide guidance to Xcel Energy to ensure distribution spending that may be approved in forthcoming rate cases is in alignment with policy goals established through the IDP."

Fresh Energy supports moving forward with a cost-benefit analysis for discretionary portions of the distribution budget, specifically the asset health and reliability (AH&R) category. This is addressed further below.

Regarding point (b), Fresh Energy concurs with Xcel that there is an important distinction between rate cases and its IDPs and it is logical that the longer-term forward-looking distribution budget proposed in an IDP will not exactly match the distribution expenditures proposed for recovery in a

rate case.[49] The Commission has addressed this issue to some extent previously; in a 2020 Order regarding Xcel's 2019 Integrated Distribution plan, the Commission modified the filing requirements for the utilities required to file IDPs to state:

"Commission review of distribution system plans is not meant to preclude flexibility for [UTILITY] to respond to dynamic changes and ongoing necessary system improvements to the distribution system; nor is it a prudency determination of any proposed system modifications or investments."[50]

As such, acceptance of an IDP is not a prudency determination of proposed investments or modifications. At the time of a rate case, the investments and modifications made within the IDP will be evaluated for prudency by the Commission.[51] Nonetheless, the IDP is an important tool for identifying the changes in planning processes, tools, and programs that the Commission deems important for the Company's distribution expenditures to advance the public interest in a changing economic and energy landscape.

In its response to this topic, Xcel notes, "to the extent the Commission has policy goals that are not reflected in our IDP, it would be helpful if the Commission could indicate those policy goals explicitly in its IDP Orders."[52] Fresh Energy agrees that as the Commission's policy objectives evolve, are refined, or as new objectives emerge, these should be explicitly directed via Orders (as is the Commission's practice) so that the Company can integrate new objectives into its budgeting and planning processes.

Both the Commission and the legislature have asked Xcel to address emerging policy issues in this IDP, especially related to cost allocation and proactive upgrades for interconnecting new electrified end uses or distributed generation. Both the Commission and legislature clearly see the IDP as a proceeding during which complex technical matters and competing policy goals can be weighed and direction can be given to the utility about how to proceed. The policy decisions made in an IDP are a material factor for the Commission to consider in subsequent rate cases, to ensure that expenditures are in alignment with prior direction.

19. Should the Commission require cost-benefit analysis for discretionary distribution system investments?

Fresh Energy believes that the Commission should require a cost-benefit analysis ("CBA") for certain discretionary programs within Xcel's Asset Health and Reliability ("AH&R") budget

[49] Xcel 2023 IDP, pp. 25-26
[50] Xcel 2023 IDP, pp. 25-26
[51] *Id*.
[52] Xcel 2023 IDP, p. 26

category[53] to more clearly demonstrate that the customer benefits of these investments exceed customer costs. As explained in a recent report by the Regulatory Assistance Project:

> "Regulators today are paying closer attention than ever to individual distribution system investment decisions, more frequently requiring utilities to transparently evaluate alternatives to meet customer needs, and increasingly requiring utilities to file long-term distribution system plans. This increased scrutiny is sometimes applied to traditional distribution system assets like substations and transformers but is even more likely to be used to evaluate 'grid modernization' investments ...
>
> Historically, utilities have relied on least cost/best fit (LCBF) techniques to make decisions about investments in utility-owned infrastructure ... After the utility identifies something that is needed to maintain safe and reliable electric service or extend service to a new area, it then seeks the least costly way to meet the identified need in a manner that complies with all applicable legal requirements …
>
> In contrast, we apply the term 'benefit-cost analysis' to methods that compare the costs and benefits of investment alternatives to assess and *maximize the net benefits* (i.e., benefits minus costs) when viewed from an agreed perspective. This can include situations where the options being considered include the status quo or a 'take no action' alternative ... Benefit-cost analysis techniques can contribute to decisions that better serve the public interest than decisions made solely based on traditional least cost methods."[54]

Fresh Energy notes that, in Illinois' ongoing multi-year integrated grid plan ("MYIGP") proceedings, the Illinois Commerce Commission rejected the initial MYIGPs of Commonwealth Edison and Ameren IL, largely because the utilities failed to demonstrate the cost-effectiveness of proposed investments using a CBA.[55] Both utilities are developing CBA methodologies for all distribution system investment categories and will include the analysis and results in revised MYIGPs to be filed March 13, 2024.

Xcel addresses CBAs in its IDP, stating "it is not efficient to conduct a CBA for all discretionary work," and "the volume of projects in the distribution five-year budget makes CBAs for each project impracticable and costly".[56] Fresh Energy agrees that conducting a CBA for every project is impracticable and therefore proposes that Xcel focus on developing a CBA methodology for the following six AH&R categories, which combine for $1.26 billion of planned 2024-2028 expenditures (34% of the 2024-2028 total).

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[53] This includes the IDP categories of Age-Related Replacements and Asset Renewal, and System Expansion or Upgrades for Reliability and Power Quality.
[54] Shenot, J., Prause, E., & Shipley, J. (2022). *Using Benefit-cost Analysis to Improve Distribution System Investment Decisions: Issue Brief*. Regulatory Assistance Project.
[55] Illinois Commerce Commission Docket Nos. 22-0486 and 22-0487, Final Orders, December 14, 2023.
[56] Xcel 2023 IDP, p. 24.

- Substation Renewal Programs[57] ($161 million budget from 2024-2028[58])
- Line Renewal Programs
    - Network Renewal[59] ($34 million)
    - Line Equipment Renewal[60] ($517 million)
    - Pole Related Renewal[61] ($203 million)
- Proactive Asset Health - Discrete Projects[62] ($137 million)
- Cable Replacement Program[63] ($207 million)

Xcel implies that it cannot "objectively quantify the annual risk" for AH&R programs,[64] yet Xcel already quantifies the risk for many of its assets. For example, Xcel evaluates substation assets at the end of their useful life, considering historic failure rates, asset criticality, and other factors to determine if the asset needs replacement or can remain in service without any significant reliability concerns.[65] This type of analysis can be a building block in a broader CBA methodology for Substation Renewal Programs.

Xcel also states, "there is not yet sufficient stakeholder consensus on which specific projects are indeed 'discretionary' to be able to narrow the list of those projects that could be subjected to a CBA."[66] Fresh Energy is proposing the six AH&R categories above, and requests that other stakeholders provide their perspectives in Reply Comments.

Finally, in response to a Fresh Energy information request, Xcel has indicated that it is willing to collaborate with stakeholders in 2024 to develop an approach for strategically applying CBAs to program-level investments.[67] We request that Xcel, in its Reply Comments, confirm its willingness to collaborate in developing a CBA methodology for the six categories proposed above.

20. Should the Commission discontinue IDP Requirement 3.A.9 as requested by Xcel?

Yes, Fresh Energy agrees that the Commission should discontinue IDP Requirement 3.A.9.

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[57] Xcel 2023 IDP, Appendix D, p. 12. Includes proactive replacement of substation equipment (e.g., transformers, breakers, switches, regulators, relays, etc.)
[58] Xcel provided 2024-2028 budgeted amounts for these categories in its responses to Fresh Energy IRs 34 and 45.
[59] Xcel 2023 IDP, Appendix D, p. 12. Includes proactive replacement of network transformers, protectors and vault tops.
[60] *Id*. Includes proactive replacement of porcelain cutouts, arrestors, reclosers, etc.
[61] *Id*. Includes pole fire mitigation, multi-feeder pole mitigation.
[62] *Id*. Includes discrete rebuild projects targeting aging equipment or infrastructure including substation rebuilds and 4kV conversions.
[63] Xcel 2023 IDP, Appendix D, p. 13. A criteria-based program to replace tap and mainline cable.
[64] Xcel 2023 IDP, Attachment D, p. 2 states that Capacity is the only IDP category for which Risk Scores are applicable because it is the only category where Xcel can objectively quantify the annual risk.
[65] Xcel response to Fresh Energy IR 16.
[66] Xcel 2023 IDP, pp. 24-25.
[67] Xcel response to Fresh Energy IR 6.

21. Should the Commission revise the IDP Filing Requirements for Xcel Energy to remove the requirement that financial information be reported in IDP-specific categories, as requested by Xcel?

Fresh Energy does not make any recommendations at this time.

22. What should the Commission consider or address related to enhancing the resilience of the distribution system within Xcel's IDP?

Fresh Energy does not make any recommendations at this time.

23. Has Xcel Energy appropriately discussed its plans to maximize the benefits of the Inflation Reduction Act (IRA) and the IRA's impact on the utility's planning assumptions pursuant to Order Point 1 of the Commission's September 12, 2023 Order in Docket No. E,G-999/CI-22- 624?

The latter half of Order Point 1 in the Commission's September 12, 2023 Order in Docket No. E,G-999/CI-22- 624 states:

> "In such filings, utilities shall discuss how they plan to capture and maximize the benefits from the Act, and how the Act has impacted planning assumptions including (but not limited to) the predicted cost of assets and projects and the adoption rates of electric vehicles, distributed energy resources, and other electrification measures. Reporting shall continue until 2032."

In several sections of its IDP, Xcel discusses the impact of the IRA on distribution planning – mostly noting the increasing levels of transportation electrification and solar it expects as a result of the IRA, which has impacted on the company's forecasts. Specifically, Xcel states, "Overall, the extension of the tax credit increased the expected EV adoption scenario in 2030 by approximately 20 percent and the expected solar adoption forecast in 2030 by approximately 30 percent."[68] In the IDP section on Maximizing Inflation Reduction Act, Xcel notes that standard distribution system upgrades included in the five-year budget are not eligible for IRA tax credits, however, some of the hosting capacity upgrades (placeholder amounts in the five-year budget) may be eligible for IRA tax credits if paired with a specific renewable project.[69]

Fresh Energy is satisfied that Xcel is working to include the influence the IRA is having on the distribution system in its planning. Most provisions within the IRA are resource or technology–specific provisions (i.e. electric vehicle rebates, tax credits for clean energy generation, etc.) rather than distribution-system-focused. Fresh Energy appreciates the Commission's attention to maximizing IRA benefits; over the coming decade the IRA will continue to have significant impact of the rate of the energy transition. Continued discussion in IDP dockets as to how the utility is

[68] Xcel 2023 IDP, Appendix A1, p. 47
[69] Xcel 2023 IDP. Appendix D, Section IIA. Maximizing Inflation Reduction Act (IRA) Benefits.

incorporating impacts from and maximizing benefits of the IRA will help to guide the stakeholder and utility planning processes to prioritize investment outcomes that include IRA benefits.

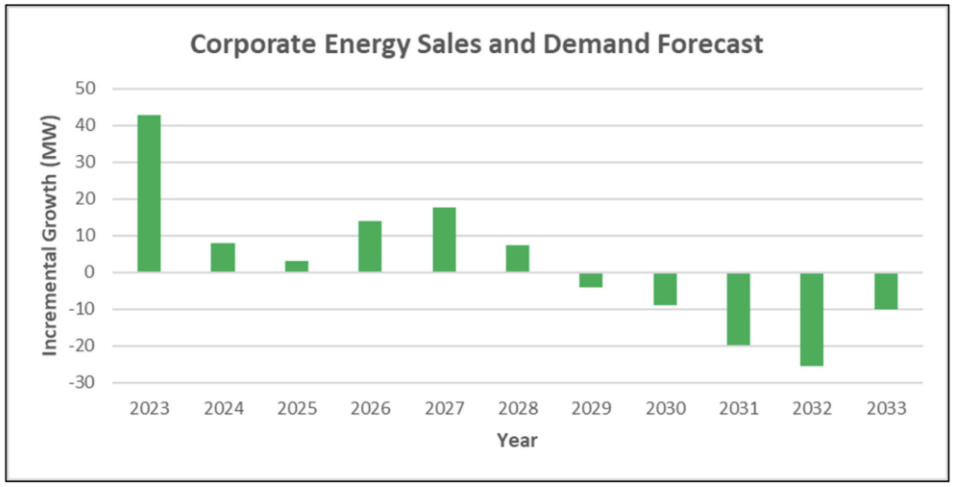
24. Other areas of Xcel's IDP or TEP not listed above, along with any other issues or concerns related to this matter.

a. Demand Side Management Capabilities

Xcel's 2023 IDP highlights significant future load-reducing impact from Demand Side Management ("DSM") resources, such as demand response and energy efficiency. As shown in Figure 2 below, Xcel forecasts negative corporate demand growth each year from 2029-2033. As an explanation, Xcel states:

> "The forecasts … include corporate growth and demand side management programs, inclusive of energy efficiency programs. During the years 2029-2033, the Company anticipates growth in demand side management programs, causing the corporate demand growth to be negative. Demand side management reduces load during peak hours, meaning that if demand side management is growing faster than local demand, then this will result in overall negative growth."[70]

Figure 2 – Corporate Demand Growth Forecast[71]



While Xcel's 2023 IDP provides this overview of DSM impacts on the corporate demand forecast, it states that the action plan for DSM "will be largely determined through a combination of the Minnesota Energy Conservation and Optimization (ECO) Triennial (both current and future) filings and the next Integrated Resource Plan (IRP), which is due February 1, 2024."[72] In response to a

[70] Xcel response to Fresh Energy IR 13.
[71] Xcel 2023 IDP, Appendix A1, p. 59.
[72] Xcel 2023 IDP, Appendix C, p. 6.

Fresh Energy information request, Xcel acknowledges that, due to timing issues, Xcel's 2023 IDP does not reflect the Company's most recent ECO Triennial plan,[73] and therefore likely underestimates the impacts of DSM programs in the 2024-2026 period.

As Fresh Energy first noted in our Response Comments in Xcel's 2021 IDP proceeding,[74] it will become increasingly important for Xcel to be able to view Demand Side Management ("DSM") as a distribution-level load-modifying resource, and to be able to design DSM programs that the Company can rely on to address local distribution needs. According to Xcel's NWA analysis, there appears to be significant load-reduction potential from existing DSM on certain feeders.[75] Yet Xcel still appears unable to incorporate such impacts into distribution planning, stating "Today, without knowing the specific load shapes and comparing them to the precise capacity constrained areas, it is difficult to predict the impact to distribution. As these processes are refined, we hope to be able to match the needed load to active demand response programs and/or develop programs that can further meet these needs."[76] Xcel already has the capability to target deployment of at least some of its DR resources to reduce load in specific geographic locations,[77] however Fresh Energy understands that the Company rarely takes advantage of this capability due to implementation challenges from disparate IT systems. This is a problem that should be rectified as more DSM capacity is available on Xcel's system, information and automation systems improve, and as Xcel deploys DERMs and other tools to manage customer-sited distribution assets. The ability to deploy DSM alongside distributed generation and storage is likely to make these applications for cost-effective and broaden potential benefits.

Fresh Energy notes, however, that at this time, our primary recommendation for improvement in Xcel's DSM programs is to *utilize* the significant demand response capacity the Company has. In other words, to call on demand response resources for economic or pre-emergency events. As highlighted in the Company's 2022 Report on Performance Based Regulation, Xcel has not called on demand response programs outside of test events in at least five years, and has used its demand response programs minimally since approximately 2008.[78] In Xcel's DSM action plan, economic dispatch of demand response, or development of new price-based demand response programs, should be a high, near-term priority. We recommend that locational DSM dispatch capabilities be included in the Company's DSM and grid modernization action plans in the medium term (2026-28), which coincides with the Company's planned timing of Distributed Intelligence and DERMS systems.[79]

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[73] Xcel response to Fresh Energy IR 7.
[74] MN PUC Docket No. 21-694, Fresh Energy Response Comments, April 11, 2022, pp. 2-3.
[75] For example, according to Xcel 2023 IDP Appendix F, p. 36, Feeder TWL078 has 13.6 MWh of available relief from DSM. The DSM measures/programs include AC Rewards (residential and commercial), Saver's Switch (residential and commercial), and Electric Rate Savings (interruptible rates).
[76] Xcel 2023 IDP, Appendix A1, p. 42.
[77] Xcel response to Fresh Energy IR 10.
[78] PUC Briefing Papers for Agenda Meeting November 2, 2023, *In the Matter of the Commission Investigation to Identify and Develop Performance Metrics and, Potentially, Incentives for Xcel Energy's Electric Utility Operations,* Docket No. E002/CI-17-401, pp. 39-45
[79] Xcel 2023 IDP, Appendix C, p. 12.

b. Integrated System Planning Unit

Fresh Energy believes that Xcel's newly formed Integrated System Planning ("ISP") business unit may present an opportunity to more tightly integrate DSM with distribution load forecasting and distribution planning. Xcel explains:

> "The purpose of ISP is to develop generation, transmission, distribution, and natural gas infrastructure investment plans that deliver on the Company's sustainability goals while keeping bills low and enhancing the customer experience. ISP also bridges the gaps between modeling tools with human processes in addition to tackling challenges of the overall planning landscape, such as inflection points with technologies – such as EVs and beneficial electrification – and pricing[80] ... we have taken steps towards ensuring alignment between the forecasts used for planning. We will continue to look for further ways to align these forecasts in the long term, as new data, modeling tools, and processes may change the way in which forecasts are generated."[81]

In response to a Fresh Energy information request, Xcel explains that the integrated system planning unit, management of DSM activities, Corporate Load Forecasting, and distribution load forecasting are currently all in separate business units, but that the organizations "work closely together."[82] Over the coming decade it will be imperative that this planning unit work to integrate the impacts of demand side management across the Company's operations, to enable new DSM capabilities with customer benefits.

Similar to the benefits that Fresh Energy believes could be seen in DSM with coordination amongst internal Xcel business units, Fresh Energy also believes that such integration would allow for more coordinated planning across the gas and electric distribution planning dockets. As Minnesota moves toward its clean energy goals and end uses continue to be electrified, it will be paramount to coordinate the planning of the gas distribution system with the modernization of the electric distribution system to avoid potentially stranded assets on the gas system. Given the gas planning dockets are in the early stages of development, we do not have a specific recommendation today as to how the coordination shall take place; however, Fresh Energy believes it will be important to improve coordination as the process unfolds.

[80] Xcel 2023 IDP, Appendix A1, p. 22.
[81] Xcel 2023 IDP, Appendix E, p. 13.
[82] Xcel response to Fresh Energy IR 9.

III. SUMMARY OF RECOMMENDATIONS

Fresh Energy's recommendations to the Commission are:

- Accept Xcel's 2023 IDP as in compliance with IDP reporting requirements.
- Require Xcel to reevaluate Integrated Volt-Var Optimization ("IVVO") to identify feeders for which IVVO is cost-effective, using the new Minnesota Test and updated assumptions informed by Public Service Company of Colorado's experience with IVVO and the Company's forecasts for electric vehicle adoption, building electrification, and distributed generation adoption.
- Direct Xcel to develop a commercial electrification forecast, as well as a more robust residential electrification forecast for its next IDP. These electrification forecasts should include low, medium, and high levels, reflecting various levels of adoption and levels of participation in load-shaping programs.
- Discontinue IDP Requirement 3.A.9.

Fresh Energy also requests that Xcel address a number of issues in its Reply Comments, as discussed further below. These include the following:

- In reference to Non-Wires Alternatives ("NWA"):
    - Based on Public Service Company of Colorado's 2023 experience, what changes does the Company plan to make to its NWA process to increase the likelihood of a successful solicitation?
    - Has Xcel confirmed with potential NWA developers that they would be willing to install DER at their own cost, with Xcel contributing only the "ARR split"?
    - Which other utilities have offered compensation only in the form of an "ARR split" in successful NWA solicitations?
    - What specific other "use cases" does Xcel envision NWAs could provide when there is no load reduction requirement?
- In reference to IVVO:
    - Please provide examples as to how responsive specific end uses (electrification of transportation, water heating, building HVAC, and heat pumps, etc.) are to IVVO and how this responsiveness may impact IVVO benefits.
    - Has the company investigated how IVVO and/or CVR can help to manage over-voltage issues in areas with high DER penetration? What were the results of this investigation?
- Regarding the 5-year capital budget:
    - Please address why a system-wide change in mitigation thresholds is more reasonable, for the purposes of planning for or accommodating customer electrification and EV adoption, than incorporating electrification and EV forecasts into Xcel's Budget Plan scenario.
    - Please verify that Fresh Energy's understanding and analysis of risk thresholds and risk counts reflected in Table 2 is correct. If it is correct, please explain 1) why the

number of risks has decreased in Xcel's current IDP compared to its 2021 IDP; and 2) why System Expansion or Upgrades for Capacity expenditures increase by 323% in 2024-2028 compared to 2019-2023 if the number of risks is decreasing.

- Regarding LoadSEER Forecasting:
    - Explain if Xcel has considered using 576-hour time series in LoadSEER, and if doing so would facilitate the incorporation of LoadSEER results into the Company's capital investment plans or sensitivities.
    - Please explain if Xcel could perform a sensitivity analysis on the relevant capital expenditure category (e.g., System Expansion or Upgrades for Capacity) using the IDP Low, Medium, or High scenario(s).
    - Please explain how Xcel could assess the geographic and temporal accuracy of LoadSEER forecasts (for example, by comparing forecasts to actual adoption patterns), and how the Company would recommend evaluating forecast accuracy.
    - Please discuss whether LoadSEER forecasts for solar, storage, EVs, and home electrification (whether in units or in *rate* of adoption) could be displayed in map form, and whether it would be feasible to do this on a census-tract level.
- In reference to Planned Net Load ("PNL") and 15% Dependability Factor
    - Does Xcel agree with Fresh Energy's analysis and conclusions summarized below for the PNL example feeder provided by Xcel on 2/14/24? If not, please explain why.
    - Does Xcel agree that only considering 0.6% of nameplate capacity as dependable PV is overly conservative? If not, please explain why.
    - In the PNL example, please explain why Xcel is using values for native and net peak load from different hours on different days.
    - In the PNL example, please explain why Xcel is using a value for net peak load during an hour where solar production is zero.
    - Please explain why Xcel is proposing to apply a 15% dependability factor to the PV generation impact and not the total nameplate capacity of PV generation.
    - Please explain why Xcel is deriving the dependability factor from average winter PV output instead of average summer output, when the majority of Xcel's feeders peak in the summer months.
- Regarding Potential Cost Sharing and/or Proactive Upgrades:
    - Please describe how grid upgrade costs are currently allocated today for: residential level 1 and 2 EV chargers, commercial level 1 and 2 EV chargers, DC fast chargers, residential beneficial electrification, commercial beneficial electrification, and distributed generation and storage projects.
- Please confirm that the Company will work with stakeholders in 2024 to develop a cost-benefit analysis methodology for six categories of discretionary Asset Health & Reliability expenditures (totaling $1.26 billion from 2024-2028) to demonstrate that customer benefits exceed customer costs.
- Please address our recommendations that Xcel's DSM action plan prioritize a) near-term (2024-25) expansion of behavioral, price-based, and pre-emergency demand response programs, and b) medium-term (2026-28) development of programs to utilize locational DSM dispatch capabilities.

Fresh Energy appreciates the opportunity to comment on the important matters under consideration here. Thank you for the Commission's time and consideration of our comments.

Respectfully submitted,

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