MINNESOTA
PUBLIC UTILITIES COMMISSION

Staff Briefing Papers

Meeting Date	July 24, 2025	Agenda Item **2
Company	Northern States Power Co. d/b/a Xcel Energy	
Docket No.	E002/CI-24-318 In the Matter of a Commission Inquiry into a Framework for Proactive Distribution Grid Upgrades and Cost Allocation for Xcel Energy	
Issues	1. Should the Commission establish a framework for Proactive Distribution Upgrades for Xcel Energy?	
Staff	Hanna Terwilliger hanna.terwilliger@state.m.us	651-201-2243

✓ **Relevant Documents**	**Date**
Initial Comments	
Minnesota Power	May 8, 2025
Union of Concerned Scientists (UCS)	May 8, 2025
Office of the Attorney General	May 8, 2025
Department of Commerce	May 8, 2025
Alliance for Transportation Electrification (ATE)	May 8, 2025
Fresh Energy	May 8, 2025
Environmental Law and Policy Center, Vote Solar, and Cooperative Energy Futures (ELPC/VS/CEV)	May 8, 2025
Minnesota Solar Energy Industries Association (MnSEIA)	May 8, 2025
Interstate Renewable Energy Council (IREC)	May 8, 2025
Coalition for Community Solar Access (CCSA)	May 8, 2025
Xcel Energy	May 8, 2025
American Council for an Energy-Efficient Economy (ACEEE) *Filed under "Public Comment – Daivie Ghosh"*	May 12, 2025

Relevant Documents	**Date**
Reply Comments	
Clean Energy Economy Minnesota (CEEM)	June 2, 2025
Environmental Law and Policy Center, Vote Solar, and Cooperative Energy Futures (ELPC/VS/CEV)	June 2, 2025
Fresh Energy	June 2, 2025
Xcel Energy	June 2, 2025
Coalition for Community Solar Access (CCSA)	June 2, 2025
Minnesota Solar Energy Industries Association (MnSEIA)	June 2, 2025
Other Documents	
PUC – Ex Parte Communication	July 11, 2025
PUC – Attachment A, Draft Proactive Distribution Upgrade Framework	July 14, 2025
PUC – Attachment B, Workgroup Slides and Roster	July 14, 2025

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Acronyms

ADP	Advance Determination of Prudence
BTM	Behind the Meter
CIAC	Contribution In Aid of Construction
CSG	Community Solar Garden
DER	Distributed Energy Resources
DG	Distributed Generation
DGEG	Distributed Generation Engagement Group
DGWG	Distributed Generation Working Group
DSES	Distributed Solar Energy Standard
EV	Electric Vehicle
FI	Flexible Interconnection
FTM	Front of the Meter
IDP	Integrated Distribution Plan
MN DIP	Minnesota Distributed Energy Resource Interconnection Process
NWA	Non-Wires Alternative
TEP	Transportation Electrification Plan
TPS	Technical Planning Standard

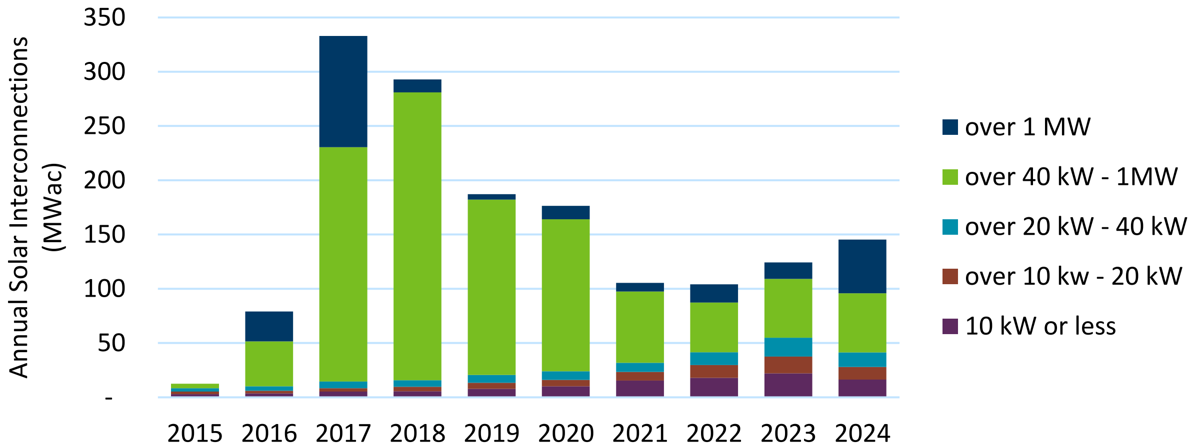
1. Statement of the Issues

1. Should the Commission establish a framework for Proactive Distribution Upgrades for Xcel Energy?
2. Which requirements from the Draft Proactive Distribution Upgrade Framework, as outlined in Attachment A, should the Commission adopt?
3. Does the Draft Framework address the following topics from the Commission's September 16, 2024 Order in Docket E002/M-23-452?
4. Should the Commission establish Phase 2 of the Proactive Distribution Grid Upgrade Proceeding and if so, what should the scope and timeline be?
5. Are there other issues or concerns related to this matter?

2. Introduction

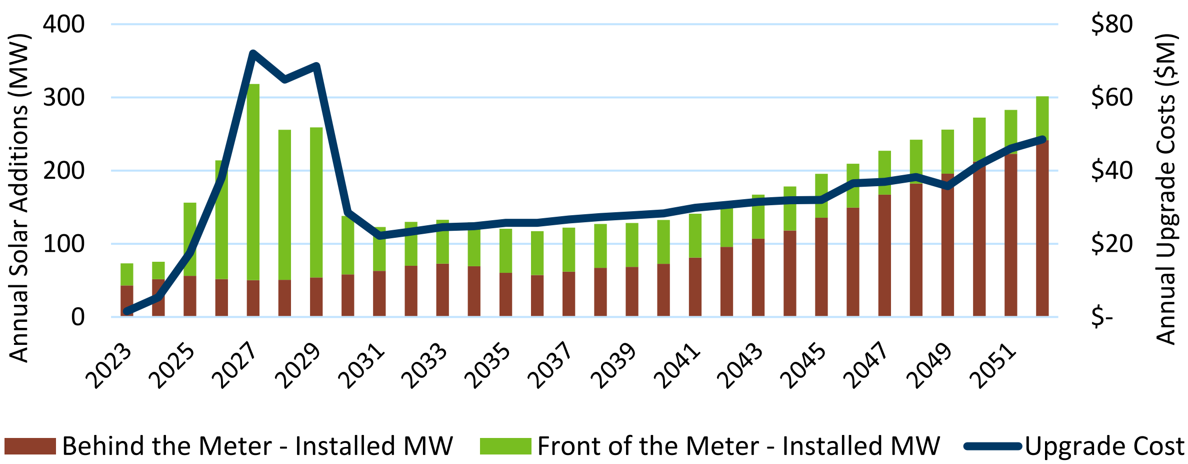
Minnesota has seen large amount of distributed energy resources (DERs), the vast majority of which are distributed solar, interconnect with utility distribution systems over the past decade. Figure 1 depicts the annual solar additions in Minnesota each year since 2015. In total there are over 1.6 GW of solar interconnected with Minnesota's distribution utilities.

Figure 1: Annual Distributed Solar Additions in Minnesota (MWac)[1]



The amount of distributed solar in Minnesota is in large part due to the growth of Xcel Energy's Community Solar Garden (CSG) program in the late 2010s. While the early 2020s saw a slowdown in adoption, new state policies passed during the 2023 Minnesota State Legislature session led to a large amounting of new solar applications with over 1.2 GW in Xcel Energy's queue as of July 1, 2025.[2] The Legislature realized the potential for significant growth in DERs and required Xcel to provide a forecast of the necessary distribution upgrades required to accommodate the new resources with its Integrated Distribution System Plan (IDP). In its 2023 IDP, Xcel Energy forecasted that 5.4 GW of solar will be added to its distribution system by 2052 and will require $992 million in upgrades. This is depicted in Figure 2.

Figure 2: Annual Forecasted Distributed Solar Additions and Estimated System Upgrade Costs for Xcel Energy[3]



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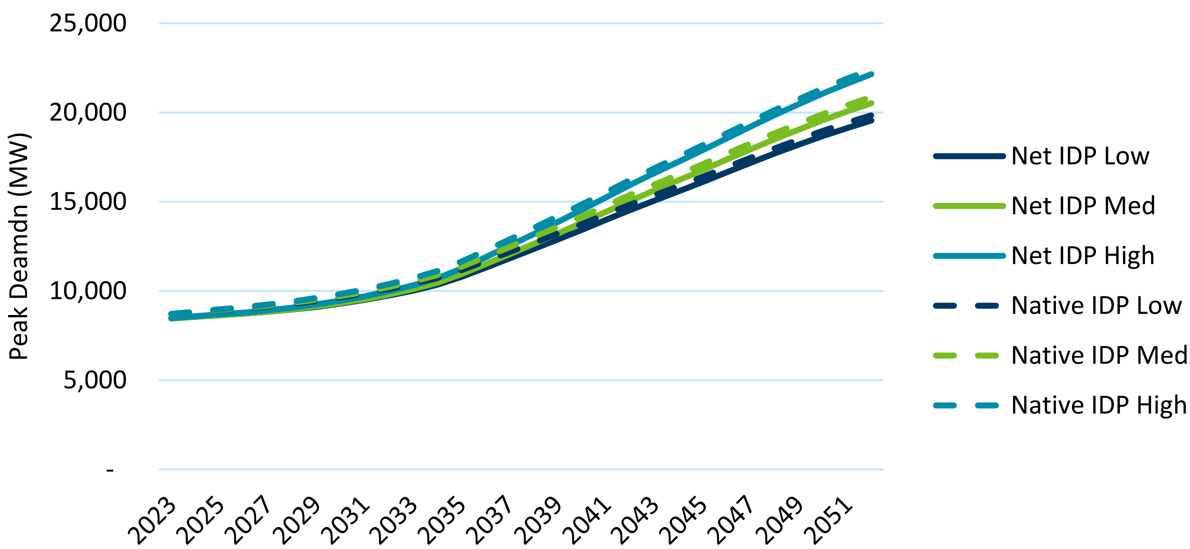
[1] Annual Distributed Energy Resource Reports, Docket 25-10.

[2] Xcel Energy, Public Distributed Energy Resources (DER) Queue – Report Date 07-01-2025. https://mn.my.xcelenergy.com/s/renewable/developers/interconnection. Retrieved July 11, 2025.

[3] Xcel Energy, 2023 Integrated Distribution Plan, Docket 23-452, Appendix I

Simultaneously, Xcel Energy is forecasting substantial amount of load growth on its system due to electrification of space heating, water heating, and the transportation system. In its 2023 IDP the Company forecasted an increase of 11 to 13 GW to its distribution system peak by the early 2050s, depicted in Figure 3.

Figure 3: Xcel IDP Scenarios: 30-Year Distribution Peak Demand Forecast (MW)[4]



A peak growth of this size would be a 140% increase over 2023 levels. The “Net IDP” scenarios account for the impacts of forecasted distributed solar additions on reducing the system peak.

The growth in load and DERs is occurring on a distribution system that is rapidly aging and facing significant costs to replace end-of-life equipment. Additionally, Xcel’s system is already strained by existing DER interconnections with some areas in the Company’s service territory facing decades long waits and millions of dollars in upgrade costs to interconnect new solar.

In the face of these challenges, the Legislature, through Minn. Stat. 216B.2425, Subd. 9, and the Commission, through its IDP process, started looking into ways to more efficiently and economically manage the transformation of the distribution system. The Legislature required Xcel Energy to provide the following information starting with its 2023 IDP:

> Subd. 9.**Integrated distribution plan; contents.** The public utility that owns a nuclear generating plant must include the following information in the public utility's annual integrated distribution plan filed with the commission, beginning with the plan due November 1, 2023:
>
> (1) a forecast of distribution system upgrades necessary to accommodate the interconnection of distributed generation resulting from the utility's compliance with

[4] Xcel Energy, 2023 Integrated Distribution Plan, Docket 23-452, Attachment M

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.

Xcel filed Appendix I to its 2023 IDP in compliance with the statute, which included a discussion of potential methods of cost allocation for distribution grid upgrades.[5] The Company also included the following budgets in its 5-year budget forecast:

- $190 million placeholder estimate for proactive system upgrades to increase DER hosting capacity.[6]
- $132 million for the Grid Reinforcements Program to proactively upgrade the grid for increased load from electrification.[7]

The Commission received robust comments on this topic, a summary of which can be found on pages 42 through 53 of Staff Briefing Papers for the July 2, 2024 Agenda Meeting in Docket E002/M-23-452. Two key concepts emerged: whether Xcel should engage in proactive distribution upgrades, and how costs for such upgrades should be allocated and recovered from DER customers and ratepayers. In its initial 2023 IDP comments, Fresh Energy offered the following matrix (replicated from Staff briefing papers) which depicts the relationship between proactive and reactive upgrades and different cost allocation options, and the risks and benefits under each set of options:

[5] Docket E002/M-23-452, Xcel Energy, 2023 IDP Part 3 of 3, Appendix I, November 1, 2023
[6] Docket E002/M-23-452, Xcel Energy, 2023 IDP Part 2 of 3, Appendix D, November 1, 2023, p. 5 (PDF p. 94)
[7] Docket E002/M-23-452, Xcel Energy, 2023 IDP Part 2 of 3, Appendix D, November 1, 2023, p. 6 (PDF p. 95)

Table 1: Cost Allocation and Proactive Upgrade Matrix[8]

	Proactive Upgrades	Reactive Upgrades
Shared Cost Allocation	• Build distribution budgets around DER and electrification forecasts. • Assign incremental infrastructure costs via typical class cost allocation methods, e.g., in next rate case. • 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.	• 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. • 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.
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. • 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.	• 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. • For the most part the model in place today • Benefit is ensuring upgrades are used and useful. • Risks include wait time and interconnection costs for DER and electrification customers.

Currently Xcel operates under the lower right-hand corner, reactive upgrades and individually allocated costs. Under the "traditional" grid planning process, the Company annually analyzes its distribution system to determine where upgrades, replacements, and other initiative are necessary which leads into the creation of a five-year budget.[9] This means that in general, Xcel

[8] Docket E002/M-23-452, June 20, 2024 Staff Briefing Papers, Xcel Energy's 2023 IDP, Table 9, p. 48: Fresh Energy, Initial Comments, March 1, 2024, Table 3, p. 17-18. Staff included risks and benefits from the following paragraph in the matrix.

[9] Docket E002/M-23-452, Xcel Energy, 2023 IDP Part 1 of 3, Appendix A-1, November 1, 2023, p. 3-4 (PDF p. 57-58)

is looking five years into the future when it does its load forecast to determine whether capacity upgrades are necessary to accommodate new load. Historically this worked well in an era of flat or slow load growth, as a utility can have confidence that an upgrade will be able to serve customers through the end of its asset life. This changes in an area of high load growth when repeated upgrades may be necessary to accommodate electrification. Proactive planning addresses the issue by looking beyond the traditional five-year planning horizon to forecast load and DER adoption so the utility can right-size an upgrade or equipment replacement for future needs. As noted above however, this comes with risks that the forecast will not be accurate, which could increase costs for ratepayers.

Commenters in Xcel's 2023 IDP generally agreed that additional record development was necessary before taking further action due to the complexities of moving from a "reactive" approach to grid planning to one that is proactive. The Commission concurred, and adopted Order Point 14 in its September 16, 2024 Order in Docket E002/M-23-452 which delegated authority to the Executive Secretary to establish a stakeholder process to develop a framework on cost allocation and proactive upgrades for Xcel Energy. The Commission set a goal of completing a draft by July 1, 2025.

Commission Staff convened the Proactive Distribution Grid Upgrade Workgroup starting in November of 2024 and continuing through March of 2025. Members of the workgroup collaboratively developed the draft framework (Attachment A) over a series of five meetings. The workgroup did not aim to reach consensus, therefore within the draft framework there are certain requirements that exist as alternatives to one another. The workgroup membership roster and meeting materials have separately been filed as Attachment B.

Throughout the course of the framework development the workgroup identified certain issues that would need additional consideration before adoption, and Commission Staff proposed establishing a Phase 2 following the conclusion of the initial framework adoption. Staff notes that one of the primary reasons for proposing a Phase 2 was to ensure the workgroup met its target deadline of July 1, 2025 for publishment of a draft framework. Staff understands that multiple commenters reserved proposals on topics such as advanced cost allocation and incorporation of front of the meter forecasting on Staff's recommendation of establishing Phase 2 of the proceeding.

On April 7, 2025 Commission Staff issued a Notice of Comment Period on the draft Framework for Proactive Distribution Upgrades

On May 8, 2025 the following organizations filed initial comments:

- Minnesota Department of Commerce (Department)
- Minnesota Office of the Attorney General, Residential Utilities Division (OAG)
- Xcel Energy (Xcel)
- Minnesota Power (MP)
- Union of Concerned Scientists (UCS)

- Alliance for Transportation Electrification (ATE)
- Fresh Energy
- Environmental Law and Policy Center, Vote Solar, and Cooperative Energy Futures (ELPC/VS/CEF)
- Minnesota Solar Energy Industries Association (MNSEIA)
- Interstate Renewable Energy Council (IREC)
- Coalition for Community Solar Access (CCSA
- American Council for an Energy-Efficient Economy (ACEEE)

On June 2, 2025, the following organizations filed reply comments:

- Xcel Energy (Xcel)
- Fresh Energy
- Environmental Law and Policy Center, Vote Solar, and Cooperative Energy Futures (ELPC/VS/CEF)
- Minnesota Solar Energy Industries Association (MNSEIA)
- Coalition for Community Solar Access (CCSA)
- Clean Energy Economy Minnesota (CEEM)

On July 24, 2025 this matter came before the Commission.

The balance of this briefing paper describes the draft Proactive Grid Upgrade Framework, which sections the Commission should adopt, and whether the Commission should establish a Phase 2 of the proceeding to address unresolved issues.

Staff separately filed Attachment A which is the complete draft framework. Rather than replicate individual portions in the briefing paper, Staff elected to have two individual documents for easier side-by-side comparison while reviewing the briefing papers.

The Proactive Distribution Upgrade Framework is divided into ten sections that outline how Xcel Energy would propose, and how the Commission would evaluate, a Proactive Grid Upgrade Proposal. Staff outlines at a high level what the sections cover here, with more details about individual components in Section 5 of the briefing papers

A. **Introduction**: outlines the overall goals and principles for the draft framework.
B. **Definitions**: defines key terms for the purposes of the framework
C. **Process**: covers when and where a proactive upgrade proposal would be filed, eligibility criteria for upgrades, and whether previously approved projects require ongoing reapproval. It also covers ongoing stakeholder engagement, both for updates to the Framework and for utility engagement ahead of a filing.
D. **Baseline Information**: requirements for information the utility should provide as part of its IDP filed concurrently with the proactive upgrade proposal
E. **Forecast**: requirements for the forecast the utility must file in support of its Proposal. This includes different forecast sensitivities, technical assumptions, and duration.
F. **Potential Sites for Proactive Upgrades**: outlines what information must be submitted for each proposed upgrade, including cost, size, timing, coordination with other

distribution work, such as reliability or age-related upgrades, and additional benefits from the upgrade. It also includes information on sites that the utility analyzed but chose not to upgrade.

G. **Proactive Upgrade Proposal Evaluation Criteria**: the criteria the Commission will use to decide which proactive upgrades should proceed. Criteria include total cost and capacity gained, how long the project will meet forecasted needs, whether there are additional benefits, and feasibility.
H. **Proposals for non-location specific proactive measures**: proposals for proactive initiatives that may not be associated with a particular location.
J. **Cost Recovery**: describes options for cost recovery, the length of the cost share window, cost caps, and prudency review.
K. **Cost Allocation**: outlines how the costs of a Proactive Upgrade are recovered from interconnecting customers and ratepayers.
L. **Capacity Reservation**: provides the option for the Commission to adopt a capacity reservation for under 40kW generation and/or residential and small commercial load at proactive upgrade locations.
M. **Reporting**: information that the utility must file in an annual report on the status of approved proactive upgrade projects.

The Commission may adopt a framework using **Decision Option 2**. Specific framework provisions may be adopted using **Decision Option 3**, which contains non-disputed provisions, and **Decision Option 4** (disputed provisions). Under Decision Option 4, the Commission would need to fill in the provisions it wishes to adopt. Staff suggests the following deliberation outline for how to structure discussion at the July 24, 2025 Agenda Meeting:

- Questions, discussion, and decision on whether the Commission should adopt a framework (**Decision Option 2**) and whether the draft framework addressed the topics from the Commission's September 16, 2024 Order (**Decision Option 1**).
- Questions and discussion on the individual sections of the framework, going in the order listed in the briefing papers (**Decision Options 3 and 4**). Staff suggests that Commissioners make one motion with all framework components as there are some interdependencies between sections. Staff also recommends that the Commission draft its motion, then take a break to confer with Staff to ensure all the necessary provisions have been adopted, given the large number of subsections within the framework.
- Questions, discussion, and decision on whether to establish a Phase 2 and what topics should be included (**Decision Options 5 and 6**).
- Questions, discussion, and decisions on any remaining decision options (**Decision Options 7, 8, and any new decision options**).

Staff will request stakeholders provide both their preferred decision options and an update on the individual framework provisions they support, oppose, or take no position on and will file a compilation of this information prior to the agenda meeting.

Finally, in multiple sections commenters caught small technical errors, such as numbering or reference inaccuracies. Staff incorporated these changes into the draft framework, and, as noted in Section 8 – Technical Issues, provided decision options to clean up any additional inconsistencies rather than needing to correct them through decision options. Staff also updated terminology throughout the draft framework to align with the definitions in Section B; for example, changing "proactive upgrade" to "Proactive Distribution Upgrade." Staff did not redline these changes in the draft framework as it believes they should all be technical in nature.

3. Should the Commission Adopt a Framework?

Participants universally supported the Commission adopting a framework for Proactive Distribution Upgrades for Xcel Energy (**Decision Option 2**). However, some participants noted that the proposed draft framework is a starting point, and without a Phase 2 that incorporates forecasting for front of the meter generation, advanced cost allocation methodologies, and other topics, the work is unfinished.

Minnesota Power (MP): Minnesota Power supported a framework that provides flexibility as demand for DERs evolves.[10]

Union of Concerned Scientists (UCS): UCS emphasized that historical grid planning practices will be insufficient to meet increased customer demand and state energy goals related to electrification and distributed generation, necessitating a proactive approach to distribution upgrades. [11]

Office of the Attorney General (OAG): The OAG noted that proactive planning can bring risks that are not present under the historical planning process, but when adequate ratepayer protections are included, such as in the framework, proactive planning can bring important benefits. The OAG explained that the existing practice of using Contribution In Aid of Construction (CIAC) for load, and the "cost-causer pays" for generation for distribution upgrades has protected ratepayers from excessive costs caused by a single customer. However, the OAG noted the existing model was not designed to accommodate the rapid expansion of electrification and DERs, necessitating the current discussion about proactive grid upgrades and cost allocation. The OAG emphasized that planning the system on a longer time horizon increases the chance of forecast errors that could lead to stranded assets and increased costs for ratepayers. Therefore, it recommended the Commission adopt framework provisions that mitigate risk by doing the following:

- Apply granular site- and project-evaluation criteria to help ensure that the most beneficial sites and upgrades receive priority;
- Require Xcel to collect cost-share fees from interconnecting customers to defray the burden on ratepayers; and

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[10] Minnesota Power, Initial Comments, p. 1
[11] UCS, Initial Comments, p. 1-2

- Impose an overall cap on the amount of proactive-distribution-upgrade costs that can be recovered from ratepayers.[12]

Department of Commerce: The Department noted it initially was skeptical of proactive upgrades due to the size of Xcel's initial placeholder budgets in its last IDP, along with the vagueness of how upgrades would be prioritized and determined. However, the Department explained these concerns were addressed through participation in the stakeholder group and recommended establishing a framework.

Alliance for Transportation Electrification (ATE): ATE expressed enthusiastic support for the proposed framework, noting that there are significant risks with a reactive approach to grid upgrades, including:

- Unmet customer expectations for energization timelines
- A slowed pace of electrification—resulting in lost utility revenue and a missed opportunity to put downward pressure on electric rates
- Customer technology lock-in, as customers opt for non-electric alternatives in face of lengthy energization timelines
- Potential for higher long-term costs for ratepayers due to a piecemeal distribution grid upgrade approach
- Potential for missed state energy policy goals

Fresh Energy: Fresh Energy strongly supported the establishment of a framework, stating that it was a necessary step toward distribution grid planning that can accommodate increased DERs and electrification.[13]

Environmental Law and Policy Center, Vote Solar, and Cooperative Energy Futures (ELPC/VS/CEF): ELPC/VS/CEF recommended adoption of the Draft Framework, citing three goals it could help advance:

- Anticipate Adoption Speed: Increased adoption speed of DERs and electrification by removing grid barriers.
- Coordinate Impacts: Avoided risk of construction/procurement bottlenecks.
- Efficiency: Degree of lifecycle cost reduction or overall spending efficiency achieved. The utility may identify areas with planned project or maintenance work where it could also realize efficiency savings by simultaneously making a proactive investment that it might have otherwise delayed under its traditional planning paradigm.

ELPC/VS/CEF acknowledged that engaging in proactive upgrades creates additional risk for utility ratepayers, but stated the Framework appropriately recognizes and addressed that risk through comprehensive evaluation of potential sites, provisions for cost recovery and allocation, and robust reporting requirements.[14]

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[12] OAG, Initial Comments, p. 2-3
[13] Fresh Energy, Initial Comments, p. 2
[14] ELPC/VS/CEF, Initial Comments, p. 2-4

Minnesota Solar Energy Industries Association (MNSEIA): MNSEIA supported adopting the Framework as a "first step" to address the cost allocation barriers that currently plague DER interconnections. However, they noted that the framework is incomplete without incorporation of front of the meter generation into the forecasting, along with further refinements to other areas of the draft.[15]

Interstate Renewable Energy Council (IREC): IREC supported the draft framework as a starting point for the next phase, but noted it is currently incomplete especially as it pertains to cost allocation.[16]

Coalition for Community Solar Access (CCSA): CCSA supported establishing a proactive upgrade framework, but reserved comment on the specifics of the proposal until Phase 2, given that the Phase 1 draft did not address front-of-the-meter generation. CCSA noted that multiple other states have recognized the importance of proactive grid planning to avoid current system inefficiencies, such as:

- A piecemeal approach to modernizing grid infrastructure;
- A need to reconstruct previously completed upgrades as additional system needs become known.
- Regulatory uncertainty for distribution and interconnection customers with respect to costs and construction timelines.

CCSA emphasized that Phase 2 should focus on "comprehensive proactive planning" that includes multi-beneficiary pays cost allocation, flexible interconnection, DER demand assessment, a DER infrastructure upgrade prioritization methodology, and a robust stakeholder engagement process.[17]

Xcel Energy: Xcel supported the establishment of a proactive upgrade framework and outlined four key benefits it could provide:

1. Streamline regulatory review of upgrade projects
2. Reduce reactive upgrades and customer wait times.
3. Reduce persistent capacity constraints.
4. Meet future increased load forecasts from new end uses.[18]

American Council for an Energy-Efficient Economy (ACEEE): ACEEE recommended adoption of the draft framework, stating that it can ensure necessary electric infrastructure is in place to serve oncoming EV loads in a cost-effective manner.[19]

[15] MNSEIA, Initial Comments, p. 3
[16] IREC, Initial Comments, p. 3
[17] CCSA, Initial Comments, p. 2-4
[18] Xcel Energy, Initial Comments, p. 2-3
[19] ACEEE, Initial Comments, p. 1-2

4. Does the proposed framework address the topics from the notice?

In the Notice for Comment, the Commission asked whether the framework addressed the topics listed in the Commission's September 16, 2024 Order that established the Proactive Grid Upgrade workgroup.

Xcel, Minnesota Power, and CCSA provided a high-level analysis of compliance with the Commission's Order.

Xcel claimed that the Draft Framework addressed all the topics from the September 16, 2024 Order and provided a table citing where in the framework they believe the requirements are met.[20]

Table 2: Order Topics in Relation to Framework Sections

	Order Topic	Section(s) in Draft Framework
1	How to allocate the costs of proactive upgrades.	Section K – Cost Allocation
2	How to ensure any proactive upgrades are distributed in an equitable manner throughout a utility's service territory.	Section F – Potential Sites for Proactive Upgrades Section G – Proactive Upgrade Proposal Evaluation Criteria Section K – Cost Allocation
3	If costs are socialized among ratepayers, whether portions of the upgraded capacity should be reserved for certain customer classes.	Section L – Capacity Reservation
4	How a proactive upgrade program would integrate with a utility's planned distribution investment programs.	Section C – Process Section H – Proposal for Non-Location Specific Proactive Measures
5	How a utility's other capacity programs and changes to distribution standards impact available hosting capacity.	Section K – Cost Allocation Section L – Capacity Reservation
6	How to determine where and when there is a need for proactive upgrades using forecasted DER and load adoption.	Section C – Process Section E – Forecast
7	Whether there should be changes to any of a utility's service policy provisions such as Contributions in Aid of Construction (CIAC).	Section K – Cost Allocation Section L – Capacity Reservation

[20] Xcel, Initial Comments, p. 7

Minnesota Power believed that the Draft Framework adequately addressed the topics established by the Commission's September 16, 2024 Order.[21]

CCSA stated that the Draft Framework broadly meets the requirements in the Commission Order for load and behind-the-meter DER interconnections, but they have not been met for front-of-the-meter DER which they stated is "essential to the proactive planning process."[22] CCSA added that in order to meet the full requirements "Phase 2 must occur as soon as possible to address the interconnection of front-of-the-meter DERs."[23]

Other participants explained how and where the Draft Framework specifically addressed each topic in the Commission Order.

i. Topic 1: How to allocate the costs of proactive upgrades

The Department and ELPC/VS/CEF stated that the Draft Framework addresses cost allocation in Section K.[24] The Department also noted that the Workgroup proposes that Phase 2 work to further develop the understanding of cost allocation and examine advanced methodologies.

IREC stated that the Framework only partially addresses this topic specifying that "allocation of costs for investments with co-benefits to both new load and generation" was not addressed.[25]

ii. Topic 2: How to ensure any proactive upgrades are distributed in an equitable manner throughout a utility's service territory

The Department stated that the Draft Framework "addresses the equitable distribution of proactive upgrades projects throughout" and that Section A.4, F.4, and G.10 notably address equity concerns and environmental justice.[26] ELPC/VS/CEF agreed with the Department on F.4, and G.10, stating that those sections along with M.4 and M.5, which requires the utility to track approved proactive projects located in EJ communities, "provide transparency into whether and to what extent these disadvantaged communities benefit from this proactive upgrade process."[27]

IREC stated that the Draft Framework did not adequately address this topic. They added that the draft "sets equitable distribution of costs as an overarching objective but does not provide comprehensive guidance on how to achieve this objective" and that "more work is needed to define exactly how to ensure an equitable distribution of costs."[28]

ACEEE stated that "while the draft framework does attempt to include environmental justice considerations in the criteria for selecting proactive upgrade projects and sites, the framework does not propose any minimum standards, scoring thresholds, or qualitative rubric by which

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[21] Minnesota Power, Initial Comments, p.2
[22] CCSA. Initial Comments, p. 6
[23] CCSA. Initial Comments, p. 6
[24] The Department, Initial Comments, p. 7; ELPC/VS/CEF, Initial Comments, p. 11
[25] IREC, Initial Comments, p. 3
[26] The Department, Initial Comments, p. 8
[27] ELPC/VS/CEF, Initial Comments, p. 12
[28] IREC, Initial Comments, p. 3-4

the equitable distribution of proactive grid upgrades will be assessed."[29] ACEEE suggested that Phase 2 could "consider a minimum percentage of projects or proportion of benefits realized from the upgrades that will occur in EJ communities based on Minnesota's goals and/or relevant policies."[30]

iii. Topic 3: If costs are socialized among ratepayers, whether portions of the upgraded capacity should be reserved for certain customer classes.

The Department stated that the capacity reservation topic in Section L.26 as well as section L in the Phase 2 attachment address this topic. [31] EPLC/VS/CEF stated that they do not recommend an explicit capacity reservation but agreed with the Department and believe the workgroup "developed various capacity reservation options for stakeholder and Commission consideration."[32] IREC also agreed that this requirement was met.[33]

iv. Topic 4: How a proactive upgrade program would integrate with a utility's planned distribution investment programs

The Department believed that the Draft Framework adequately addresses this topic and included B.16 (Proactive Distribution upgrade), E.5 which described proactive upgrades being based on a 5-10 year forecast, and G.5 which the Department stated contrast the standard process to the proactive process.[34] ELPC/VS/CEF also agreed with the Department regarding B.16 and also cite C.1 "which requires the utility to file any Proactive Upgrade Proposal in conjunction with its IDP filing."[35]

v. Topic 5: How a utility's other capacity programs and changes to distribution standards impact available hosting capacity.

The Department stated that this topic was met via Sections E.6, G.11, and K.1 of the Draft Framework.[36] ELPC/VS/CEF also cited K.1 of the Draft Framework which "explains that any changes to distribution planning or other utility standards that impact the amount of available hosting capacity after the utility completes a proactive upgrade project do not affect the established cost-sharing responsibility." [37]

vi. Topic 6: How to determine where and when there is a need for proactive upgrades using forecasted DER and load adoption.

The Department stated that Section E of the Draft Framework "addresses the Forecast, its assumptions, and how a proposed project must be based on a forecasted need within a

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[29] ACEEE, Initial Comments, p. 4-5
[30] ACEEE, Initial Comments, p. 5
[31] The Department, Initial Comments, p. 8
[32] ELPC/VS/CEF, Initial Comments, p. 12
[33] IREC, Initial Comments, p. 4
[34] The Department, Initial Comments, p. 12
[35] ELPC/VS/CEF, Initial Comments, p. 12
[36] The Department, Initial Comments, p. 9-10
[37] ELPC/VS/CEF, Initial Comments, p. 13

specified time frame" and cited several subsections.[38] The Department also cited subsections of Section F and Section 4 of the Phase 2 attachment as other mentions of the forecasted need for proactive upgrades. ELPC/VS/CEF cited Section E as well and also cited Section G which "addresses the evaluation process the Commission can use to determine whether or not to approve particular proactive upgrade proposals." [39] IREC also believed the Draft Framework addresses this topic.[40]

ACEEE stated that they believe the Draft Framework "provides sufficient details on what the utility should include when forecasting for load adoption" but emphasized that the outlined stakeholder process "will be critical in informing the need for these proactive upgrades, their locations, and importantly, provide some confidence in need for the upgrades."[41] ACEEE also offered specific ways utilities could consider including suggestions for electric buses and electric truck fleets.

vii. Topic 7: Whether there should be changes to any of a utility's service policy provisions such as Contributions In Aid of Construction (CIAC)

The Department believed Section K and specifically Section K.7 adequately addressed this topic. The Department also pointed to the Phase 2 topics, flexible interconnection and advanced cost allocation and recover that they believed will further support this topic.[42] ELPC/VS/CEF agreed that Section K covers this topic and that they specifically support Sections K.2 – K.6.[43]

viii. Staff Analysis

Staff agrees with commenters that either the framework or the workgroup process at minimum discussed the issues in the Commission's Order. While some areas could use additional development, they can be expanded on in Phase 2. Staff recommends the Commission adopt **Decision Option 1** which finds that workgroup addressed the topics listed in the Commission's September 16, 2024 Order.

5. Which portions of the Framework should the Commission Adopt?

A. Introduction

A.3 is unopposed and may be adopted with **Decision Option 3**

i. A.1 and A.2

A.1 and A.2 are alternatives. The OAG, Department, and MNSEIA opposed A.1, while ELPC/VS/CEF, Fresh Energy, and UCS supported it. Xcel did not oppose A.1. All commenters either supported or took no position on A.2.

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[38] The Department, Initial Comments, p. 10-11
[39] ELPC/VS/CEF, Initial Comments, p. 13
[40] IREC, Initial Comments, p. 4
[41] ACEEE, Initial Comments, p. 4-5
[42] The Department, Initial Comments, p. 11
[43] ELPC/VS/CEF, Initial Comments, p. 13

The Department suggest that A.1 implies "proactive upgrades are required to meet state energy policy requirements and goals," however it views proactive upgrades as a tool to meet state goals.[44] Similarly, the OAG explained that A.1 assumes upgrades are necessary to meet state policy requirements but does not explicitly list any. According to the OAG if there was a requirement for utilities to undertake proactive upgrades, the Legislature would have explicitly stated that intent. Therefore, the OAG recommended A.2 as it "appropriately shifts the goal's focus to planning for upgrades that are necessary to enable customer DER and electrification, considering state energy policy requirements and goals."[45]

ELPC/VS/CEF agreed that the Draft Framework aims to upgrade the distribution system to enable customer DER and electrification adoption, as noted in A.2. However, they preferred A.1 as it provided more flexibility and acknowledges the framework may advance additional goals, such as affordability and system efficiency.[46]

Supports A.1: ELPC/VS/CEF, Fresh Energy, UCS (Xcel not opposed)
Supports A.2: OAG, Department, MNSEIA, Xcel, MP

ii. A.4 and A.5

A.4 and A.5 are alternatives.

Xcel preferred A.5, stating that it "provides greater clarity on the risks and costs" the framework seeks to minimize.[47] Xcel also explained that the term "rigorous" in A.4 is vague, and risks review becoming unnecessarily burdensome due to a lack of clarity.[48] ATE concurred, stating that it "may not be possible to ensure that the proactive investment process is risk-free" as contemplated under A.4. Instead, A.5 seeks to minimize risk rather than eliminate it.[49]

ELPC/VS/CEF recommended adoption A.4, as it provides a stronger emphasis on ratepayer protection when reviewing proactive upgrades.[50] The Department agreed, stating that the "rigorous review" contemplated in A.4 would avoid the stranded assets mentioned in A.5.[51] The OAG also recommended A4, stating that A5 shifts the focus to the risk of stranded assets when there are other ways that a proactive upgrade could cause costs to ratepayers, such as an upgrade being underutilized.[52]

[44] Department, Initial Comments, p. 4
[45] OAG, Initial Comments, p. 5
[46] ELPC/VS/CEF, Initial Comments, p. 5
[47] Xcel, Initial Comments, Attachment 3, p. 1
[48] Xcel, Reply Comments, Attachment 1, p. 1
[49] ATE, Initial Comments, p. 3
[50] ELPC/VS/CEF, Initial Comments, p. 5
[51] Department, Initial Comments, p. 4
[52] OAG, Initial Comments, p. 6

In response to the OAG, Xcel noted that A.5 should address the concern that stranded assets are not the only source of undue costs due to inclusion of "projects that result in inequitable distribution of costs or benefits."[53]

Supports A.4: OAG, Department, MNSEIA, ELPC/VS/CEF
Supports A.5: Fresh Energy, UCS, Xcel, MP, ATE

iii. A.6 and A.7

A.6 and A.7 are alternatives

Xcel and ATE preferred A.7 as adding "to the extent reasonably possible" provides a better balance than A.6 given the level of risk inherent in proactive upgrades.[54] ELPC/VS/CEF and the Department believed that adding "to the extent reasonable possible" was unnecessary as the Commission always seeks to make decisions in line with practicability.[55]

Supports A.6: ELCP/VS, Department, OAG, MNSEIA, Fresh Energy
Supports A.7: Xcel, ATE, UCS, MP

iv. A.8 and A.9

A.8 and A.9 are alternatives.

Xcel explained that A.9 is a better option to balance the risk of an inaccurate forecast as "all forecasts will be inaccurate because they attempt to predict the future."[56] ATE agreed, stating it is more appropriate to evaluate forecasts based on the information that was known at the time the forecast was made."[57] ELPC/VS/CEF and the Department disagreed and recommended A.8, stating the Commission should always seek protect ratepayers from forecast inaccuracies, regardless of whether they are "unreasonable."[58]

Supports A.8: ELCP/VS, Department, OAG, MNSEIA, Fresh Energy, UCS
Supports A.9: Xcel, ATE, MP

v. A.10 through A.15

A.10 through A.15 establish principles for cost allocation and cost recovery associated with the framework. All commenters either supported or took no position on A.10, sets a goal to limit deviations from traditional cost allocation and recovery methodologies. A.11 through A.15 contain more specific recommendations on cost allocation and have varying levels of support and opposition.

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[53] Xcel, Reply Comments, Attachment 1, p. 1
[54] Xcel, Initial Comments, Attachment 3, p. 1; ATE, Initial Comments, p. 3; Xcel, Reply Comments, Attachment 1, p. 2
[55] ELPC/VS/CEF, Initial Comments, p. 5; Department, Initial Comments, p. 4
[56] Xcel, Initial Comments, Attachment 3, p. 1; Xcel, Reply Comments, Attachment 1, p. 2
[57] ATE, Initial Comments, p. 4
[58] ELPC/VS/CEF, Initial Comments, p. 6; Department, Initial Comments, p. 4

ELPC/VS/CEF did not recommend adopting any provisions in A.10 through A.15, stating that A.5/A.5, A.6/A.7, and A.8/A.9 already cover similar topics. They also noted that while the principle of cost-causer pays is an important consideration, there may be limited reasons why socializing some portions of upgrades costs in reasonable for public policy or administrative reasons. Instead of adopting principles for cost allocation in the current framework, ELPC/VS/CEF recommended deferring a decision until after Phase 2 after more development around advanced cost allocation methodologies.[59]

Xcel supported A.10 and A.11 and opposed A.12. The Company explained that "when appropriate" under A.11 "provides sufficient flexibility and clarity, without introducing the redundancy of "whenever possible." Additionally, the Company emphasized the rate case as the location to determine cost allocation methods.[60] The Department preferred A.12 but noted the difference between A.11 and A.12 was minimal and it could support either option.[61]

Xcel opposed A.13 as it "implies the use of custom allocation formulas to assign project costs based on perceived benefits." The Company reemphasized the necessity of determining cost allocators in a rate case and cautioned against creating new allocation methodologies for proactive upgrades. The Company also opposed A.14, finding the revision to introduce ambiguity into "whether this language would require adherence to the rate case methodology or allow deviations from it."[62]

Xcel opposed A.15, stating it "conflates cost allocation with cost causation" and "risks introducing inconsistency by suggesting that benefit distribution alone should drive cost allocation, regardless of causation or established rate case methodologies."[63]

UCS supported including a consideration of benefits when determining the appropriate cost allocation methodology. It reasoned that while DERs and electrification may impose costs on the grid, they also can provide benefits to all ratepayers especially when there are appropriate utility run programs. Therefore, UCS supported A.14 and A.15

The OAG emphasized that adoption of A.12 and A.13 is critical to protecting ratepayers from cross-subsidization. It noted that A.12 and A.13:

> Reflect the idea that traditional principles of cost-allocation—where costs are allocated to the cost-causer—should be used whenever it is possible to determine cost causation. As a fallback, when specific customers or classes are not responsible for upgrade costs, as will usually be the case with proactive upgrades, those costs should be allocated according to what customers or classes benefit from the upgrades.[64]

[59] ELPC/VS/CEF, Initial Comments, p. 6
[60] Xcel, Reply Comments, Attachment 1, p. 3
[61] Department, Initial Comments, p. 4
[62] Xcel, Reply Comments, Attachment 1, p. 3
[63] Xcel, Reply Comments, Attachment 1, p. 3
[64] OAG, Initial Comments, p. 7

***Staff Analysis*:** Staff agrees with ELPC/VS/CEF that adoption of cost allocation principles may be premature, especially since decisions in later parts of the framework may end up in conflict with some of the principles outlined in A.10 through A.15. Staff suggests that to the extent the Commission wishes to establish principles for cost allocation, it do so in combination with the consideration of advanced cost allocation methodologies as part of Phase 2.

Supports A.10: OAG, Department, MNSEIA, Xcel, MP
Supports A.11: Fresh Energy, UCS, Xcel
Supports A.12: OAG, Department, MNSEIA, MP
Supports A.13: OAG, Department, MNSEIA
Supports A.14: Fresh Energy, UCS, MP
Supports A.15: MNSEIA, Fresh Energy, UCS

Alternative: consider any cost allocation principles as part of Phase 2 (**Decision Option 6.e)**

B. Definitions

Sections Xcel.B.2, B.3, B.4, B.5, B.6, B.9, B.10, B.11, B.12, B.13, and B.17 are unopposed and may be adopted with **Decision Option 3**.

Staff made minor modifications to several definitions by adding the word "Proactive" to "Cost Share Customer," "Cost Share Fee," and "Cost Share Window" to differentiate from the definitions in the reactive workgroup. Staff does not believe this addition changes the overall definition but is an important clarification between this and the Reactive Cost Share process in Docket 24-288. This modification is included in the attached draft framework.

i. B.1-Xcel.B.2: Proactive Cost Share Customer

While B.1 was included in the draft framework, after initial comments stakeholders all supported B.2 over B.1. As Xcel explained, it "is necessary to clarify that a Cost-Share Customer is a customer responsible for paying a Cost-Share Fee." Xcel also proposed adding additional language stating "unless otherwise specified in approved tariffs" to the end of the definition as, depending on which other framework provisions are adopted, there may be some instances where a customer interconnects at a proactive upgrade location but does not directly pay the Cost-Share Fee.[65] No commenters objected to Xcel's modification in Reply Comments. Staff recommends adoption of Xcel's modification as part **Decision Option 3**.

Supports B.2 or Xcel.B.2: OAG, Department, MNSEIA, ELPC/VS/CEF, Fresh Energy, UCS, Xcel, MP

ii. B.7 and B.8: Distributed Generation.

B.7 and B.8 are alternatives to one another. B.7 aligns with the definition in Minn. Stat. 216B.1611, the interconnection statute while B.8 is a revision of B.7 to be more broadly applicable to any generation facility interconnected with the distribution system that operates in parallel with the utility.

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[65] Xcel, Initial Comments, Attachment 3, p. 1

Xcel and ELPC/VS/CEF supported using B.8 as it is more broadly applicable than B.7, which limits the types of DG facilities that could fall under the framework.[66]

The Department recommended adopting B.7 as it aligns with existing processes, specifically the inclusion of a reference to the Minnesota Distributed Energy Resource Interconnection Process (MN DIP).[67]

In reply comments, Xcel indicated it is open to including "and is eligible for interconnection under the Minnesota Distributed Energy Resources Interconnection Process" in the definition.[68]

***Staff Analysis**:* Staff is comfortable with Xcel's proposed compromise to include a reference to MN DIP in its proposed definition. Staff believes it would be useful tie the definition to MN DIP as it is likely any Proactive Cost-Share Fees collected as part of the program will occur at some point in the MN DIP process. Staff offers Staff.B.8 which incorporates Xcel's proposed modification. Staff also notes the updated draft contains a correction to both B.7 and B.8 that accurately states the acronym for MN DIP.

Staff.B.8 Distributed Generation (DG): a generation facility that ~~has a capacity of 10 MW or less,~~ is interconnected with a utility's distribution system~~,~~ operates in parallel with the utility, and is eligible for interconnection under the Minnesota Distributed Energy Resource Interconnection Process (MN DIP).

Supports B.7: Department, MNSEIA, Fresh Energy
Supports B.8: ELPC/VS/CEF, Xcel

Staff Alternative: Staff.B.8 (combination of B.7 and B.8)

iii. B.14 and B.15: Proactive Upgrade Proposal

Xcel proposed adding additional language to the definition of a proactive upgrade proposal that delineates the difference between a "traditional" distribution investment and a proactive investment in B.15.[69]

ATE opposed B.15, stating that Xcel's addition is more closely aligned with the definition of a Proactive Distribution *Upgrade* and does not belong in the definition of a Proactive Upgrade *Proposal.* Furthermore, it includes a presumption of imprudence under existing practices, which ATE stated was unnecessary as it presumes to know what the Commission would decide.[70] ELPC/VS/CEF made a similar argument, stating that "prudency evaluation is a fact-based inquiry, and we do not believe pre-judging any particular prudency determination within the definitions in this Draft Framework is appropriate."[71] The Department also opposed B.15, stating that the "discussion of prudency is unnecessary in the definition of a Proactive Upgrade

[66] Xcel, Initial Comments, Attachment 3, p. 1; ELPC/VS/CEF, Initial Comments, p. 6
[67] Department, Initial Comments, p. 4
[68] Xcel, Reply Comments, Attachment 1, p. 4-5
[69] Xcel, Initial Comments, Attachment 3, p. 1
[70] ATE, Initial Comments, p. 4
[71] ELPC/VS/CEF, Initial Comments, p. 7

Proposal."[72] The OAG noted that Xcel's proposed language seemed to imply that proactive planning is inherently imprudent, which the OAG disagreed with. It also explained that Xcel's additional language was misplaced and should be in the definition of a proactive upgrade, rather than the definition of a proposal.[73]

In reply comments Xcel noted that it is essential to have this differentiation to explain why the Framework is necessary. It also rebutted the OAG's concern that the definition implies imprudence, noting that instead it "clarifies that these projects may not meet the prudency standards of traditional planning processes precisely because they are forward-looking and strategic in nature." The Company did not object to moving the language to B.16, the definition of a "Proactive Distribution Upgrade" if that would improve the framework clarity.[74]

Staff Analysis*:* Staff does not share Xcel's concern about including more explicit language about prudency in the definition, and in general agrees with other commenters that including it could be construed as some kind of pre-judgement. Staff also agrees with ATE and the OAG that even if this definition were to be included, it would be more appropriate in B.16, the definition of a proactive upgrade. However, if the Commission would prefer to more clearly delineate between a traditional investment and a proactive investment, Staff would suggest modifying the language to remove the word "prudent" from the definition and incorporating it into a new Staff.B.16:

Staff.B.16 Proactive Distribution Upgrade: a distribution upgrade made solely based on a forecasted need outside a utility's traditional planning cycle. In the context of this framework, a proactive distribution upgrade would not be considered under existing distribution planning processes due to the proactive nature of the project.

Staff believes this could provide a compromise. The new definition that signifies there is a difference between the planning and selection processes for a proactive upgrade and a traditional project but removes the concern around the use of the word "prudency," which seems to be at the root of commenter's concerns. If the Commission selects Staff's B.16, it should also select B.14. If the Commission selects B.14 or B.15, it may choose either B.16 or ATE.B.16, as discussed below.

Supports B.14: OAG, Department, MNSEIA, ELPC/VS/CEF, UCS, ATE
Supports B.15: Fresh Energy, Xcel, MP

Staff Alternative: adopt B.14 and Staff.B.16

iv. B.16 and ATE.B.16: Proactive Distribution Upgrade

ATE suggested aligning the definition of a proactive upgrade with Lawrence Berkeley National Lab's definition, "distribution system proactive investments [are] those that are deployed

[72] Department, Initial Comments, p. 4
[73] OAG, Initial Comments, p. 8
[74] Xcel, Reply Comments, Attachment 1, p. 6

ahead of certain load growth. These may include investments to serve new loads ahead of the utility receiving a load letter, as well as investments deployed to serve expected load growth that do not target an existing system constraint."[75]

Xcel objected to ATE's proposal, stating that it could "broaden the framework to include projects that utilities already undertake today" as utilities still plan ahead of "certain" load from customers within the traditional planning cycle, albeit on a much shorter time horizon than contemplated under the framework. Therefore, Xcel maintained its support for B.16.

Staff Analysis*:* Staff supports the original B.16. The definition proposed by ATE excludes distributed generation, which is a key component of the framework. If the Commission selects Staff.B.16, it will not need to adopt ATE.B.16 or B.16

<u>Supports ATE.B.16</u>: ATE
<u>Supports B.16</u>: OAG, Department, MNSEIA, ELPC/VS/CEF, Fresh Energy, UCS, Xcel

Staff Alternative: Staff.B.16

C. Process

Sections C.1, C.2, C.3, C.4, C.8, and C.9 are unopposed and may be adopted with **Decision Option 3.**

i. <u>C.5 through C.7</u>

While C.5 and C.7 were included in the draft framework, after initial comments stakeholders all either support C.6 or Xcel.C.6.

The Department and ELPC/VS/CEF supported C.6. The Department supported including a flexible definition of what qualifies as a "significant change," while ELPC/VS/CEF noted that a significant change could also be a change to timelines or other factors.[76]

Xcel explained that if there was a constant risk of rereview of existing projects for any reason the Company would deem that an unacceptable level of risk and would be unlikely to move forward with any projects.[77] In reply comments, Xcel explained its "primary concern is the potential requirement to seek reapproval after project costs have already been incurred or construction has begun, particularly in response to forecast changes." The Company did note that it does support reapproval in cases where there is a forecast change before any project costs are incurred and offered modified language in Xcel.C.6 to balance the concerns of all stakeholders.[78]

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[75] ATE, Initial Comments, p. 4
[76] Department, Initial Comments, p. 5; ELPC/VS/CEF, Initial Comments, p. 7
[77] Xcel, Initial Comments, Attachment 3, p. 1
[78] Xcel, Reply Comments, Attachment 1, p. 6-7

Xcel.C.6 Previously approved projects do not require reapproval in subsequent Proactive Upgrade Proposal evaluations unless circumstances have changed significantly. Significant changes include ~~but are not limited to~~ scope changes to the project that would substantially impact overall project cost, and changes to the forecast that substantially impact the need for the project. Projects that have already been initiated are not subject to reapproval.

Staff Analysis*:* Staff notes that Xcel proposed its revised language in Reply Comments, therefore the Commission may wish to consult with other stakeholders on the revised language. Staff also makes an important clarification that C.6 does not dictate what stakeholders are allowed to bring up during prudency review during separate cost recovery proceeding, which is covered in Section J of the framework, but rather indicates what is fair game for reexamination during a subsequent Proactive Distribution Upgrade Proposal proceeding.

Supports C.6: OAG, Department, MNSEIA, ELPC/VS/CEF, Fresh Energy, UCS, MP
Supports Xcel.C.6: Xcel

ii. C.10 and C.11: Stakeholder Engagement

Sections C.10 and C.11 pertain to stakeholder engagement ahead of a Proactive Distribution Upgrade Proposal filing. C.10 requires Xcel to engage with stakeholders ahead of finalizing the forecast that informs its proactive upgrade proposal and provides an opportunity for written feedback from stakeholders. C.11 would establish a Distributed Generation Stakeholder Engagement Group (DGEG) that would coordinate long-term proactive planning with the utility. The DGEG would consist of elected DG industry representatives, the utility, the OAG, and the Department.

C.10 and C.11 are not mutually exclusive, but if both adopted would result in overlapping activities. The OAG, Department, ELPC/VS/CEF, Fresh Energy, UCS, Xcel, MP, and ACEEE supported C.10. MNSEIA, CCSA, and CEEM supported C.11. Groups supporting C.10 did not unilaterally oppose C.11 but recommended that it be referred to Phase 2 for further development.

UCS summarized the importance of including stakeholder engagement as outlined in C.10:

- Builds trust by increasing transparency in the early stages of forecasting and proposal development
- Opportunities for feedback from stakeholders may increase the quality of the forecast.
- Creates accountability by requiring the utility to report on how it incorporated the feedback.[79]

[79] UCS, Initial Comments, p. 3

ACEEE emphasized that stakeholder engagement under C.10 would allow large commercial and industrial stakeholders to "identify and confirm anticipated demand in geographic areas that a utility may overlook."[80]

CCSA recommended adoption of C.11 and the formation of a DGEG. CCSA emphasized that requiring utilities to coordinate their long-term proactive planning processes with industry representatives is critical to ensuring the upgrades will serve the needs of customers and advance state policy goals. CCSA encouraged the Commission to establish the DEGE during Phase 1, stating it would "allow the DGEG to immediately start on its substantive and technical workstreams during Phase 2 without delay."[81]

MNSEIA similarly recommended adopting C.11 in its entirety during Phase 1 of the proceeding. MNSEIA explained that determining the location of proactive upgrades will be critical to ensure "the equitable distribution of usable hosting capacity across a utilities territory, while mitigating the risk of stranded assets." MNSEIA emphasized that a key component of the DEGE would be stakeholder feedback on whether the cost of a proposed upgrade will allow DG to interconnect at that location. If the cost is too high, the upgrade may be underutilized, and the state's energy policy goals stymied.[82]

ELPC/VS/CEF opposed inclusion of C.11, stating that "an additional stakeholder engagement process specifically centered on distributed generation developers is [not] necessary at this time, especially given the focus of this initial Draft Framework on smaller, behind-the-meter distributed generation." Therefore, they recommended adoption of C.10 and suggested further development of the concepts in C.11 during Phase 2.[83] Fresh Energy echoed the recommendation to discuss C.11 in Phase 2,[84] as did the Department. The Department voiced concern over the establishment of an additional stakeholder process when there may be an existing forum that could serve the same purpose.[85]

Xcel likewise opposed C.11 for the following reasons:

1. Existing Forums Are Available. The Distributed Generation Work Group, which is open to all stakeholders, already provides a venue for raising and addressing relevant issues. Additionally, the Commission's Distributed Generation Advisory Group provides a forum to consider broader policy matters. We also host quarterly meetings with all DER developers through the Minnesota DER Stakeholder Workgroup, which could further support these efforts.
2. Commission Authority Is Limited. The Commission does not have jurisdiction over developers or other non-utility stakeholders and therefore cannot mandate their participation in coordination efforts.

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[80] ACEEE, Initial Comments, p. 2
[81] CCSA, Initial Comments, p. 4-5
[82] MNSEIA, Initial Comments, p. 5-6
[83] ELPC/VS/CEF, Initial Comments, p. 7
[84] Fresh Energy, Initial Comments, p. 8
[85] Department, Initial Comments, p. 12

3. Utility Role in Stakeholder Engagement. A utility's responsibility in this process should be limited to gathering and considering stakeholder input for forecasting purposes. Stakeholders are free to self-organize and submit consolidated feedback for consideration.
4. Obligation to Serve All Customers Equitably. Utilities are statutorily required to provide adequate and reliable service at reasonable rates without granting preferential treatment.3 Granting DG developers a formalized role in shaping utility investment plans could disproportionately elevate their influence over that of load-serving customers. Developer input should be limited to informing forecasts—not to prioritizing or selecting specific projects.
5. Discretion in Incorporating Input. Utilities must retain the discretion to incorporate developer input only when it is appropriate and aligns with broader system planning and service obligations.

Therefore, Xcel supported C.10 and recommended further discussion of C.11 during Phase 2.[86]

In reply comments, MNSEIA, CCSA, and CEEM pushed back against moving consideration of C.11 to Phase 2. In response to concerns about resource constrains, MNSEIA indicated that this workgroup would be focused on MNSEIA member companies who are willing to engage in this work. In MNSEIA's opinion, C.11 "provides value incremental to what C.10 provides in that it provides an opportunity for input and cross industry collaboration and dialogue" while C.10 "only provides the opportunity for input in the form of written comments on initial forecasting and the proposed upgrade locations." MNSEIA explained the workgroup could "offer input on available land suitable for DG development, permitting issues in the region of the upgrade, and the potential for supply chain constraints and customer delays."[87]

CCSA pushed back on Xcel's assertion that establishing a DGEG would be an administrative burden, stating that forming the groups in Phase one is "a vital mechanism to ensure transparency, local expertise, and market insight inform planning decisions" and "without this inclusive forum, the risk of misaligned investments or inequitable outcomes grows."[88]

CEEM strongly recommended establishing the DGEG, stating that "it is imperative that there be a transparent, robust exploration of fundamental issues confronting a utility and the vast available opportunities and methods by which to maximize the penetration of Distributed Energy Resources (DERs) so as to attain the renewable energy requirements set forth in Minnesota law." CEEM requested the Commission amend C.11 to include clean energy interest groups in addition to DG develops in the DGEG.[89]

Staff Analysis: Staff echoes the concerns of the Department, Xcel, Fresh Energy, and ELPC/VS/CEF that C.11 requires further development prior to adoption. Specifically, Staff is

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[86] Xcel, Reply Comments, Attachment 1, p. 8-9
[87] MNSEIA, Reply Comments, p. 3
[88] CCSA, Reply Comments, p. 4
[89] CEEM, Reply Comments, p. 2-4

concerned by C.11.a which outlines the makeup of a DGEG. The Commission cannot require participation in a stakeholder workgroup by entities other than the utility, including for the Department of Commerce and the OAG, as it lacks regulatory jurisdiction. Staff is also concerned that the DGEG would not be open to all participants, such as consumer advocates, EV industry representatives, large load entities, or other advocacy organizations. In contrast, C.10 outlines a process that is open to all stakeholders and requires Xcel to share preliminary forecasting results and accept feedback. Staff anticipates that the Company would hold either virtual or in person meetings to share the analysis and provide opportunities for verbal as well as written feedback, as it has done in prior stakeholder engagement sessions. As discussed in Section 7 – Phase 2 later in these briefing papers, Staff does see a role for more targeted engagement with DG developers to create a long-term plan for upgrades that serve front-of-the-meter generation but in a different format than contemplated under C.11.

D. Baseline Information

All sections of D are unopposed and may be adopted with **Decision Option 3.**

E. Forecast

Sections Xcel.E.1, E.2, E.3, E.5, and E.6 are unopposed and may be adopted with **Decision Option 3.**

i. E.1 and Xcel.E.1

E.1 and Xcel.E.1 are alternatives

Xcel provided a minor wording modification to E.1 to include "customer loads" instead of "electrification," stating that electrification is not the only type of load addition it models, and that these types of customer load may also contribute to the need for a proactive project.[90] No commenters objected to this modification in reply comments. Staff recommends adoption of Xcel's modification as part **Decision Option 3**.

ii. E.4 and Xcel.E.4

E.4 and Xcel.E.4 are alternatives

Xcel proposed striking the last portion of E.4, which would require it to file forecast results for all potential sites it examined for potential inclusion in its proactive upgrade proposal. Xcel explained that while it supported including a discussion of projects it did not select, it did not believe it should have to provide forecast data for all locations as the utility should ultimately decide which sites to upgrade based on system needs. The Company also emphasized review should focus on the "merits of projects that have been proposed and should not be used debate which projects *should have* been proposed."[91]

ELPC/VS/CEF opposed Xcel's change, stating that providing forecast results for all analyzed locations would provide transparency and "better enable Commission and stakeholder

[90] Xcel, Initial Comments, Attachment 3, p. 3
[91] Xcel, Initial Comments, Attachment 3, p. 3

evaluation of this new proactive process, including whether the Draft Framework is operating as intended."[92]

Staff Analysis: Staff is unclear the extent to which Xcel's forecast conducted in support of proposed proactive distribution upgrades would differ from the forecast it performs as part of its integrated distribution plan. To the extent the forecast contemplated under E.4 is the same as the overall system forecast Xcel performs for the IDP, Staff believes a better place to consider requiring additional information is as part of the Company's IDP, as contemplated by the Department in its additional recommendations, discussed in Section 6.i – New IDP Filing Requirement of the briefing papers. Given the number of substations and feeders in Xcel's service territory, Staff wishes to be cautious about the level of information that is provided so as not to overwhelm stakeholders with unnecessary information. Staff notes there could be additional reasons beyond the forecast results that factor into the Company's decision to not include a specific site in its proactive upgrade proposal, such as timing with other maintenance work or total project cost. This is currently discussed under Subsection F.7.

Supports E.4: OAG, Department, MNSEIA, ELPC/VS/CEF, Fresh Energy, UCS, ACEEE
Supports Xcel.E.4: Xcel

F. Potential Sites for Proactive Upgrades

All sections of F are unopposed and may be adopted with **Decision Option 3.**

Staff notes that section F.1 had an incorrect reference to a portion of Section C which stakeholders mentioned in comments. Instead of adopting a specific numbering provision here, Staff left the reference blank, and it can be filled in depending on which provision under Section C the Commission adopts. As noted in a later section, Staff recommends granting the Executive Secretary authority to make this type of technical change in the final version of the Framework.

G. Proactive Upgrade Evaluation Criteria

Sections G.1, G.2, G.4, G.7, G.8, G.9, G.10, G.11, G.12, G.13, and G.16 are unopposed and may be adopted with **Decision Option 3.**

i. G.3 and MNSEIA.G.3

MNSEIA proposed adding language to G.3 that would require an analysis of historical data and interconnection customer's cost sensitivity for interconnection costs.

MNSEIA.G.3 The cost per unit of capacity gained, and a discussion informed by historical data and developer input on the maximum cost per unit of capacity gained, at or below which Interconnecting customers are likely to agree to pay to interconnect, and above which interconnection would become unviable.

MNSEIA explained that if the cost to interconnect at a proactive upgrade is higher than interconnection customers are willing to pay, it could pose long term risk to ratepayers.

[92] ELPC/VS/CEF, Reply Comments, p. 3

MNSEIA explained that including this analysis could assist the Commission in prioritizing which proactive upgrades to choose based on financial viability.[93]

In reply comments ELPC/VS/CEF noted they continue to support G.3, but do not oppose MNSEIA's proposed modification.[94]

Xcel opposed MNSEIA's proposed change. The Company noted that the original version was broadly supported in initial comments and provides a "clear, objective, and quantifiable metric that can be consistently applied across projects." In contrast, Xcel explained that "it is unclear what additional value MNSEIA's expanded language would bring to the evaluation process." The Company also noted it would be difficult for it to assess what cost levels are viable for interconnecting customers and questioned whether the utility was the correct party to provide this information.[95]

Staff Analysis*:* Staff appreciates MNSEIA's focus on providing affordable interconnection costs to customers and believes this could be helpful information to have. However, Staff agrees with Xcel that this type of analysis is not appropriate under the evaluation criteria. Instead, Staff suggests that this analysis could be incorporated into an initial evaluation of the framework. Developers could provide feedback based on their experience and based on the project costs from the initial proactive upgrade proposals, and potentially the costs from the forthcoming DER Cost Share program in Docket 24-288. Staff suggests the timing, location, and details of this analysis could be determined in an early portion of the Phase 2 proceeding discussed in Section 7 – Phase 2 of the briefing papers.

Supports G.3: OAG, Department, ELPC/VS/CEF, Fresh Energy, UCS, Xcel, ACEEE
Supports MNSEIA.G.3: MNSEIA

ii. G.5

Xcel recommended removing G.5 from the evaluation criteria, as it believed it was duplicative of G.4. The Company explained that the risk of deferring a proactive upgrade is simply that a reactive upgrade would be necessary, and that the delay would be the time to complete the upgrade.[96]

ELPC/VS/CEF disagreed with Xcel that G.4 and G.5 are redundant and recommended including both provisions. Contrary to Xcel, ELPC/VS/CEF believed that G.4 and G.5 serve different purposes: G.4 provides the lead time for a proactive upgrade, while G.5 quantifies the risk of delaying it. G.5 includes additional information on the impacts to customers of not pursuing the proactive upgrade that is not included in G.4. ELPC/VS/CEF noted this "may include delays, but may also include operational inefficiencies, bottlenecks, inability to timely meet state policy goals." Furthermore, they explained that an energization delay time may not always align with the lead time for an upgrade, as there "may be reasons for Xcel to begin upgrade construction

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[93] MNSEIA, Initial Comments, p. 6-7
[94] ELPC/VS/CEF, Reply Comments, p. 4
[95] Xcel, Reply Comments, Attachment 1, p. 10
[96] Xcel, Initial Comments, Attachment 3, p. 3

sooner than the forecast date for its need (i.e., have a shorter lead time), for example, to take advantage of operational efficiencies."[97]

Staff Analysis: Staff concurs with ELPC/VS/CEF that G.4 and G.5 serve related, but different purposes in evaluating whether a proactive upgrade should move forward. Staff notes that one of the key reasons for engaging in proactive grid upgrades is to avoid delays for customers seeking to interconnect new generation or load. Quantifying the impacts of any potential delays is a critical component of the evaluation criteria.

<u>Supports G.5</u>: OAG, Department, MNSEIA, ELPC/VS/CEF, Fresh Energy, UCS, ACEEE
<u>Opposes G.5</u>: Xcel

iii. <u>G.6</u>

Xcel opposed inclusion of G.6 as projects that meeting NWA criteria will be included in the analysis filed as part of the IDP. It also explained that if a project does not meet the IDP NWA threshold it would take up significant additional resources to complete the required analyses.[98]

Fresh Energy supported inclusion of G.6, stating that it was critical to consider alternatives, such as NWA, in order to maximize the benefits of proactive upgrades. It noted that Xcel should not be required to replicate any existing analyses, and instead provide a citation to the NWA analysis in the IDP.[99] ELPC/VS/CEF similarly supported G.6, disagreeing with Xcel that it would require additional technical analysis beyond what is already included in the IDP NWA process. Instead, ELPC/VS/CEF explained G.6 "requires Xcel to show that it has given some thought to non-capital-intensive ways it could address system needs, which may be less costly for its customers."[100] To alleviate Xcel's concern that as written G.6 would require additional lengthy analysis, ELPC/VS/CEF offered the following revised language:

> Discussion of whether Xcel Energy performed a non-wires alternative (NWA) for the project, and if so, the results of the analysis. If Xcel Energy did not perform an NWA, provide a discussion of alternative measures<u>, if any,</u> 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.

Xcel was unpersuaded and maintained its opposition to G.6 for the following reasons:

a. It would result in redundancy with existing IDP NWA requirements.
b. It would result in an increased resource burden that could result in the delay of a proactive upgrade proposal.
c. It would be an overreach of the original intent of an alternatives consideration by requiring a discussion even when the project does not quality for an NWA analysis.

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[97] ELPC/VS/CEF, Reply Comments, p. 4
[98] Xcel, Initial Comments, Attachment 3, p. 3
[99] Fresh Energy, Initial Comments, p. 5
[100] ELPC/VS/CEF, Reply Comments, p. 4-5

d. It would create a misalignment with the objectives the proactive upgrade review process, which should focus on the submitted project and not evaluating all possible alternatives.[101]

Staff Analysis*:* Staff agrees that having some kind of analysis of alternatives is an important ratepayer protection measure for the framework. While a non-wires alternative may only delay an upgrade by a few years, that might allow for better coordination with other planned equipment replacement, or for updated and more accurate forecasting to occur that results in a better sized upgrade. Staff is however conscious of the potential additional resource burden on Xcel and supports ELPC/VS/CEF's modification to more clearly outline that additional technical analysis is not required, but rather a high-level discussion of whether alternatives *could* be an option. Staff offers an additional minor modification to make it explicit that Xcel does not need to provide the entire results of an NWA, but rather a citation to where it appears in the IDP.

Revised.G.6: ~~Discussion of w~~ 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.

Staff hopes that the proposed modification could alleviate Xcel's outlined concerns.

Supports G.6: OAG, Department, MNSEIA, ELPC/VS/CEF, Fresh Energy, UCS, ACEEE
Opposes G.6: Xcel

Staff Alternative: Staff.G.6 (includes ELPC/VS/CEF modification)

iv. G.14 and G.15

ELPC/VS/CEF supported G.14, stating that it captures the specific goals of proactive upgrades:

1. Anticipate Adoption Speed: Increased adoption speed of DERs and electrification by removing grid barriers.
2. Coordinate Impacts: Avoided risk of construction/procurement bottlenecks.
3. Efficiency: Degree of lifecycle cost reduction or overall spending efficiency achieved.

ELPC/VS/CEF explained that including G.14 adds "clarity to the evaluation process for upgrade proposals" around a common set of goals that are specific to the upgrades themselves.[102]

Xcel, the Department, and the OAG supported G.15 over G.14. Xcel did not object to the overall intent in G.14 but rather believed it was covered in other parts of the framework.[103] Instead, the Company explained that G.15 offers a "streamlined and flexible way to evaluate how a

[101] Xcel, Reply Comments, Attachment 1, p. 11-12
[102] ELPC/VS/CEF, Initial Comments, p. 7-8
[103] Xcel, Initial, Comments, Attachment 3, p. 3

proposed upgrade supports the goals of proactive planning."[104] The OAG and Department both noted that the goals in G.14 do not align with those in Section A of the framework.[105] The OAG explained that if the "outcomes are important enough to be called out here, presumably they are important enough to be listed among the goals at the beginning of the framework." It also voiced a concern that the list of outcomes in G.14 "appears to be exclusive" and "implies that the Commission is to ignore the goals established in the framework's introduction when evaluating a proposed upgrade under part G."[106]

Staff Analysis*:* Staff agrees with Xcel, the Department, and the OAG that the goals outlined in G.14 would be more appropriate for Section A. If the Commission is interested in the goals outlined in G.14, Staff suggests moving them to Section A and adopting G.15, which would then cover the proposed goals.

Supports G.14: MNSEIA, ELPC/VS/CEF, ACEEE
Supports G.15: OAG, Department, Fresh Energy, UCS, Xcel, ACEEE

Alternative: Move G.14 to Section A and adopt G.15

H. Proposal for Non-location Specific Proactive Measures

The OAG and Department recommended further development of Section H in Phase 2 prior to adoption. Both explained that while it was likely non-location specific investments could provide value, it was currently unclear what they would be or how the Commission would evaluate them.[107] The OAG requested concrete examples of these types of investments, how they relate to location-specific proactive upgrades, and how they derive value for a utility's system" be provided as part of that effort.[108]

Xcel opposed H.2, stating that it was not clear what it required beyond the Company's existing practice of coordinating system maintenance with project work. Xcel explained that it already completes basic, low-cost upgrades during routine maintenance, rendering inclusion in the Framework redundant.[109]

ELPC/VS/CEF advocated for inclusion of H.1 and H.2 in the current iteration of the framework. In response to the OAG, ELPC/VS/CEF explained building additional stock of long-lead-time items, such as regulator/LTC controllers, service transformers, and substation transformers, would one of the primary activities under Section H. ELPC/VS/CEF noted that a utility may do this when it forecasts higher than usual system needs outside its planning window, such as may occur with rapid system growth from forecasted electrification. This would help avoid "future supply constraints and potentially higher costs, which may force [the utility] to defer projects when they are more immediately needed." For evaluation criteria, ELPC/VS/CEF suggested

[104] Xcel, Reply Comments, Attachment 1, p. 12
[105] Department, Initial Comments, p. 5; OAG, Initial Comments, p. 11
[106] OAG, Initial Comments, p. 11
[107] OAG, Initial Comments, p. 11; Department, Initial Comments, p. 12
[108] OAG, Initial Comments, p. 11
[109] Xcel, Reply Comments, p. 13

relying on section G, noting that while not all the criteria would apply it could be used as a starting point to justify non-location specific proactive measures. [110]

In response to Xcel's contention that H.2 is unclear, ELPC/VS/CEF stated that their understanding is for H.2 "to clarify and make transparent the utility's intent to coordinate upgrades, such as controller replacements, with maintenance activities where practical and appropriate." They acknowledged that such coordination already exists but supported including H.2 to increase transparency and capture this specific goal.[111]

Staff Analysis*:* While not opposed to continued discussion of Section H, Staff is concerned that the list of topics for Phase 2 is already large. Staff suggests leaving Section H in the initial iteration of the framework. If Xcel submits a non-location specific proposal and there is either insufficient information or evaluation criteria, the Commission may always deny the proposal and the framework can be modified to include more specific direction. Staff believes that having a concrete proposal to evaluate will be more useful in understanding this section rather than continued abstract discussions.

In regard to H.2, Staff agrees with Xcel that the requirement itself is unclear in what it is asking the utility to include in a proposal. Staff suggests that H.1 and H.2 may be combined:

Staff.H.3 Xcel Energy may propose programmatic investment proposals which are proactive distribution upgrade initiatives that affect a variety of locations, but the specific locations may shift over time in alignment with established site selection criteria. In proposing such measures or initiatives, Xcel Energy shall provide a high-level discussion of any ~~consider whether there are~~ basic, low-cost upgrades that would increase hosting capacity that are already ~~can be done as a~~ part of standard maintenance.

Staff believes this combined language would provide the transparency ELCP/VS/CEF desires without placing an additional burden on Xcel to perform new analysis or create new practices.

Move Section H to Phase 2: OAG, Department
Supports H.1: MNSEIA, ELPC/VS/CEF, Fresh Energy, UCS, Xcel, MP
Supports H.2: MNSEIA, ELPC/VS/CEF, Fresh Energy, UCS, MP

Staff Alternative: Staff.H.3

J. Cost Recovery

The cost recovery portion of the framework deals with *how* the costs of proactive upgrades will be recovered, while the Cost Allocation section deals with *who* will pay the costs. Staff notes that overlap exists between the decision options in Sections J and K, therefore Staff outlines the key items the Commission will need to decide below:

[110] ELPC/VS/CEF, Reply Comments, p. 11-12
[111] ELPC/VS/CEF, Reply Comments, p. 12

- How Proactive Cost-Share Fees will be credited towards Proactive Distribution Upgrade project costs.
- The length of the Proactive Cost-Share Window.
- Whether Proactive Cost-Share Fees will be calculated and offset towards Proactive Distribution Upgrade costs at an individual project or program level.
- Whether any socialized costs should be allocated using rate case allocators or some other methodology.

Staff made recommendations throughout the next sections, noting where subsections are duplicative of each other and in some cases providing rearranged options that break apart existing subsections, so the Commission is better able to select different provisions ala carte. Staff does not believe it has offered new or altered positions, instead the intent behind this is to improve clarity. Staff offers decision trees in Figures 5 and 6 that capture the different pathways and subsection combinations noted above.

The OAG and Xcel offered framing comments on how to approach cost recovery and cost allocation for proactive distribution upgrades.

The OAG explained that as proactive upgrades are more speculative than traditional distribution spending, cost recovery and cost allocation should be treated differently than standard investments. Specifically, the OAG highlighted the importance of collecting Proactive Cost-Share Fees from new customers that interconnect both generation and load to locations served by Proactive Distribution Upgrades to prevent free-ridership. The OAG likened this to how CIAC works under the existing "reactive" upgrade process, which protects ratepayers form excessive costs caused by one customer.[112]

Xcel emphasized the importance of a framework that provides a clear path to cost recovery with the ability to earn a return on the investments in order to proceed with Proactive Distribution Upgrades. The Company explained that there "needs to be a single process that evaluates proposed projects and leads to a Commission decision to approve, deny, or modify the project – providing the Company with certainty that it will be able to recover its prudently-incurred costs." Because proactive upgrades are by definition more speculative than historic distribution investments, there is added risk around whether the forecasted resources will materialize. Therefore, Xcel explained that there must be cost recovery protections to mitigate the risk of hindsight on a process that has already been vetted and approved by the Commission.[113]

i. Cost Recovery Mechanism

J.1 would automatically allow Xcel the option to place any approved proactive investments that are approved in service as a regulatory asset. J.1 differs from J.3 in that it is permissive, while J.3 requires the utility to place approved upgrades in a regulatory asset. The Department and

[112] OAG, Initial Comments, p. 12
[113] Xcel, Initial Comments, p. 3-4

OAG opposed J.1, while MNSEIA, ELPC/VS/CEF, Fresh Energy, and ACEEE supported it. Xcel did not oppose J.1 but preferred J.3 or J.4.

In contrast, J.2 allows Xcel to request deferred accounting treatment as part of its Proactive Distribution Upgrade Proposal and gives the Commission discretion to grant, deny, or modify the request. All stakeholders either supported or did not oppose J.2.

Xcel proposed minor revisions to J.3 for clarity which no commenters opposed. Xcel, MNSEIA, and Minnesota Power supported J.3, while the OAG, Department, and ELPC/VS/CEF opposed it.

Xcel proposed a revision to J.4 which clarifies cost-share fees are an offset to the *revenue requirements* of the capital proactive investments, rather than an offset to the *capital costs* of proactive investments. No commenters discussed J.4 in reply comments, however the OAG opposed similar language in J.7.[114] The OAG, Department, MNSEIA, Fresh Energy, and UCS supported the original version of J.4, which requires that all cost-share fees are returned to ratepayers as an offset to proactive upgrade capital investments. ELPC/VS/CEF noted that it did not oppose J.4 but questioned whether it was necessary in the draft framework.[115]

ELPC/VS/CEF supported J.1 and J.2, noting that it is “appropriate to retain flexibility regarding the treatment of upgrade investments.” While they recognized the investments may likely be recovered through deferred accounting, ELPC/VS/CEF opposed a blanket presumption of this determination as is contemplated under J.3.[116] ACEEE similarly supported J.1, explaining it would give Xcel a path to cost recovery for the investments.[117] The Department preferred J.2, stating that it “is more explicit in its direction that a utility may request tracking in a regulatory asset or deferred accounting treatment, but the approval is ultimately the decision of the Commission.”[118]

The OAG explained that the “the primary cost-recovery mechanism for proactive distribution upgrades should be through base rates, with any cost-share fees collected by Xcel serving as an offset to rate base, similar to how CIAC currently operates.” The OAG offered a new section, J.0, that states this preference.[119]

The OAG opposed J.3 because it automatically assumed the creation of a regulatory asset. In general, the OAG opposed the use of a regulatory asset and deferred accounting for proactive grid upgrades but acknowledged leaving the option open under J.2 provided flexibility for the Commission. According to the OAG use of a regulatory asset and/or deferred accounting “is unnecessary and risks unduly increasing ratepayer costs” as ratepayers will need to pay carrying charges on the capital costs in the account.[120] The OAG explained the risks as such:

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114 Xcel, Initial Comments, Attachment 3, p. 4; OAG, Initial Comments, p. 17
115 ELPC/VS/CEF, Reply Comments, p. 7
116 ELPC/VS/CEF, Initial Comments, p. 8
117 ACEEE, Initial Comments, p. 3-4
118 Department, Initial Comments, p. 5
119 OAG, Initial Comments, p. 13
120 OAG, Initial Comments, p. 14

> For a capital asset like a distribution upgrade, deferred accounting allows a utility to track the annual revenue requirements associated with the asset—primarily, depreciation expense and a return—that the utility incurs between rate cases and permits the utility an opportunity to recover those costs in a future rate case. As depreciation and return are incurred, they are added to the deferred costs in the regulatory asset. If a utility goes several years between rate cases, the regulatory asset will contain several years of depreciation expense and return. Utilities may also ask to recover a "carrying charge"—representing the time value of money—on the deferred balance to compensate them for temporarily foregoing recovery of those costs. In the case of proactive upgrades, a carrying charge would essentially mean that ratepayers are paying interest (a carrying charge) on interest (a return). The compounding effect could be substantial, especially if the regulatory asset balance is carried for several years with few or no offsetting cost-share fees.[121]

Therefore, the OAG maintained its recommendation that placing proactive upgrades in rate base should be the default option, rather than an automatic granting of deferred accounting. However, the OAG allowed that Xcel should be able to request deferred accounting for particular projects as warranted.[122]

Staff Analysis*:* As no stakeholders objected to J.2, Staff recommends adoption. While a utility always has the *option* to request deferred accounting, including it in the framework provides a pathway for the potentially substantial costs that Xcel will be requesting approval for outside of the typical rate case process.

As discussed in the next section, Staff recommends that the Commission decide on the treatment of Proactive Cost-share Fees alongside the length of the Proactive Cost-Share Window. Therefore, Staff recommends not adopting either J.4 or Xcel.J.4 as they would either duplicate or conflict with subsequent sections.

Supports OAG.J.0: OAG
Supports J.1: MNSEIA, ELPC/VS/CEF, Fresh Energy, MP (Xcel not opposed)
Supports J.2: OAG, Department, MNSEIA, ELPC/VS/CEF, Fresh Energy (Xcel not opposed)
Supports J.3/Xcel.J.3: MNSEIA, Xcel, MP
Supports J.4: OAG, Department, MNSEIA, Fresh Energy, UCS, Xcel
Supports Xcel.J.4: Xcel

ii. Proactive Cost-Share Window

The Proactive Cost-Share Window refers to the length of time during which Proactive Cost-Share Fees can be collected from Proactive Cost-Share Customers interconnecting either generation or load at a location with a completed Proactive Distribution Upgrade. At the end of the Proactive Cost-Share Window, remaining costs that have not been offset by Proactive Cost-

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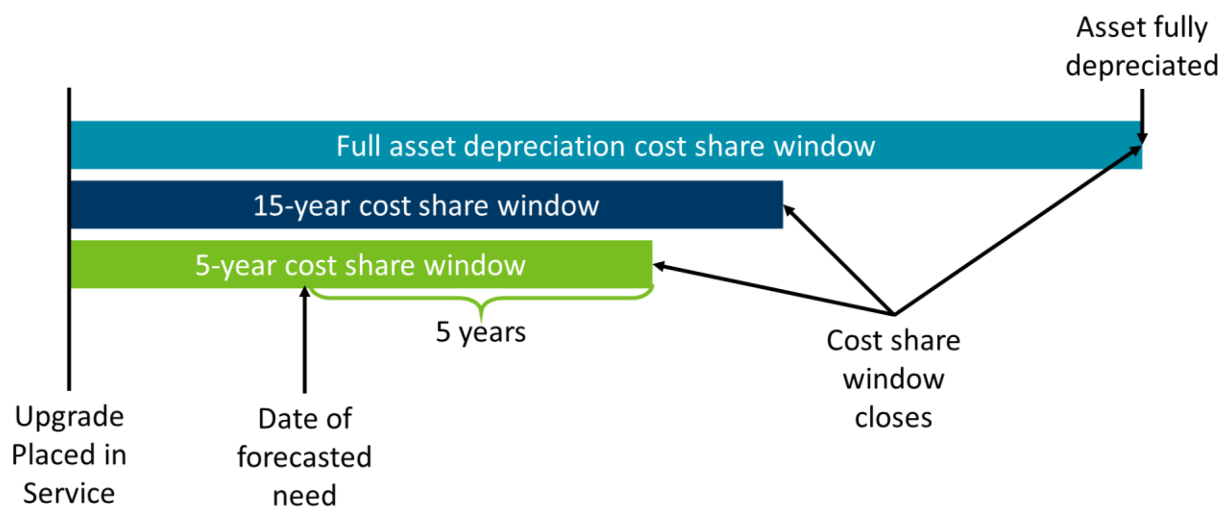
[121] OAG, Initial Comments, p. 15
[122] OAG, Initial Comments, p. 15

Share Fees and depreciation would be socialized to all ratepayers. There are three proposals for the length of the Proactive Cost-Share Window:

- 5 years from the date of the anticipated need at the time of project approval
- 15 years from the date the project is placed in service
- Until the upgrade is fully depreciated

Figure 4 provides a comparison of the different options for cost share windows.

Figure 4: Comparison of Cost Share Window Options



Under both the "full asset depreciation" and 15-year option the cost share window opens when the upgrade is placed in service. Under the 5-year option, the window opens when the upgrade is placed in service, but the countdown to the end of the cost share window does not open until the date when the utility's forecast indicated a need for the upgrade.

5-year cost share window (J.7-J.9; J.B)

Xcel supported establishing a cost share window that lasts five years from the date of the anticipated need. Under Xcel's proposal, the cost share window would open once the asset was placed in service, but the countdown would not begin until the date of the "need" which precipitated the proactive upgrade. During the cost share window, all cost share fees collected from cost share customers would serve as an offset to the revenue requirements of all proactive upgrade.[123] The Company explained that the first five years after the date of the established need is when the majority of new interconnections would be expected to occur, which would align the cost-share window and fee collection with actual demand. Xcel noted that a 5-year window "simplifies administration by avoiding indefinite tracking and promotes fairness through clearly defined eligibility criteria as defined in J.9, ensuring consistent application of cost share fees."[124] Xcel proposed an alternative to J.8 which specifies that the

[123] Draft Proactive Upgrade Framework, Subsection
[124] Xcel, Reply Comments, p. 4

costs of proactive upgrades are placed into rate base once a project is completed, rather than at the end of the cost share window. Xcel recommended adopting J.7, Xcel.J.8, and J.9

The OAG opposed J.7 and J.8 and took no position on J.9. According to the OAG, the five-year cost share window contemplated under J.7 would create two major risks. First, the shorter window would risk shifting costs to ratepayers if the expected load or generation materialized just slightly later than forecasted. Second, a shorter cost share window could also encourage free-ridership, as potential customers may delay interconnection until the cost share window closes to avoid paying a cost share fee. The OAG expressed concern that under J.7 the cost share fees would not offset the actual asset balance, but rather the revenue requirement, allowing Xcel to collect a return on a larger rate-base balance for a longer period of time. The OAG advocated for treating cost-share fees as an offset to rate base, similar to CIAC, which would reduce the overall return ratepayers would pay over the asset's lifetime.[125]

Until the asset is fully depreciated (OAG/Dept.J.6; J.C)

The OAG and Department offered identical edits to J.6, and both recommended it over J.5 and J.6.

OAG/Dept.J.6 The cost-share window for an upgrade shall remain open until the upgrade is fully depreciated to help mitigate risks to ratepayers.

The OAG explained that it originally offered a 15-year cost share window during the workgroup if the upgrade was placed in service as a regulatory asset. However, since it no longer supports regulatory-asset treatment, the OAG now recommended OAG/Dept.J.6. The OAG also noted that "foregoing any rate recovery for 15 years as suggested by J.5 increases the risk of the regulatory asset growing unreasonably large before it is moved to base rates at the end of 15 years, particularly if few or no cost-share fees are collected."[126] The OAG explained how under the revised OAG/Dept. J.6:

> Once an upgrade is in service, annual deprecation would commence, reducing the asset's balance by a set amount per year based on its expected useful life. At the same time, any cost-share fees would also be applied to reduce the asset's balance as those fees were collected. After the asset's balance had been reduced to zero on the utility's books through accumulated depreciation and fee offsets, no further cost-share fees would be collected.

The OAG explained that aligning the cost-share window with an asset's fully depreciable life would maximize ratepayer benefits by allowing a longer period during which to collect cost-share fees.[127] The Department supported OAG/Dept.J.6 as well, noting "allowing the cost-share

[125] OAG, Initial Comments, p. 16-17
[126] OAG, Initial Comments, p. 15-16
[127] OAG, Initial Comments, p. 15-16

window to remain open until the project is fully depreciated allows for the costs to be assigned to cost-causers as much as possible."[128]

Xcel opposed the new OAG/Dept.J.6, noting that the depreciable life of distribution assets can be up to 40 years which would be "unreasonable, impracticable, and administratively burdensome."[129]

15 years from in service date (J.5 and J.6; J.A)

ELPC/VS/CEF preferred the 15-year cost share window contemplated under the original J.5 and J.6, stating that the longer cost share window would protect ratepayers by providing more time to offset asset costs via cost share fees. ELPC/VS/CEF was concerned that under the five-year option, construction timelines could result in the proactive upgrade being placed in service after the date of need, which would result in a cost share window that is less than five years in length.[130]

As noted above, the OAG and Department no longer support J.5 and J.5 and instead recommend their new OAG/Dept.J.6. Xcel opposed a 15-year cost share window, stating that it would not allow recovery of costs within a reasonable time frame. The Company also expressed concern that the 15-year option did not take the timing of the *need* into account, which could mean that the cost share window would close prematurely before the relevant DER or load adoption is anticipated to occur.[131]

ELPC/VS/CEF maintained support for the cost share approach in J.5 and J.6. While it noted it did not object to the OAG/Dept.J.6, ELPC/VS/CEF explained it was "sympathetic to the concerns Xcel expressed regarding this J.5/J.6 approach around the length of the window and the burden imposed on the utility, particularly if the window is open for each asset until it is fully depreciated." ELPC/VS/CEF suggested there could be a compromise to be had by either shorting the cost share window under J.5 or lengthening the window in J.7.[132]

Staff Analysis: The concept of a cost-share window is one of the more novel and complex portions of the proactive grid upgrade framework. The length and structure of the cost-share window, combined with the structure of how cost-share fees are treated, will play a key role in mitigating ratepayer risk for proactive upgrade investments. In the current set of cost-share window subsections there is overlap between determining the length of the cost share window and the treatment of cost-share fees during the cost share window. While these two concepts are interrelated, the cost share window length need not dictate the accounting treatment of cost share fees. Therefore, Staff split certain decision options in this section (without rewriting them) to allow the Commission more flexibility as it decides this section. These are relabeled as J.A through J.I and replace J.5 through J.9:

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[128] Department, Initial Comments, p. 6
[129] Xcel, Reply Comments, p. 4
[130] ELPC/VS/CEF, Initial Comments, p. 8
[131] Xcel, Initial Comments, Attachment 3, p. 4
[132] ELPC/VS/CEF, Reply Comments, p. 7

<u>Length of Proactive Cost-Share Window:</u>

The Commission may choose J.A, J.B., or J.C. If desired, the Commission may change the length of time in J.A or J.B.

J.A Each approved Proactive Distribution Upgrade shall have a Proactive Cost-share window of at least 15 years that starts upon the upgrade being placed in service.

OR

J.B Each approved Proactive Distribution Upgrade shall have a Proactive Cost-Share Window that starts the year that the Proactive Distribution Upgrade project is placed in-service. The duration of the Proactive Cost-Share Window shall be until 5 years after the anticipated need date for the Proactive Distribution Upgrade at the time of approval.

OR

J.C The Proactive Cost-Share Window for an upgrade shall remain open until the upgrade is fully depreciated to help mitigate risks to ratepayers.

<u>Treatment of Costs during the Proactive Cost-Share Window:</u>

The Commission may choose J.D or J.E.
The Commission may select J.F AND J.G; or J.H, or neither.
It may select J.I with any options

J.D During the cost-share window, Proactive Cost-Share Fees from Proactive Cost-Share Customers act as an offset to Xcel Energy's capital investment in the Proactive Distribution Upgrade.

OR

J.E During the Proactive Cost-Share Window, Proactive Cost-Share Fees from Proactive Cost-Share Customers act as an offset to the revenue requirements of all Proactive Distribution Upgrades.

J.F No costs are socialized to ratepayers during the Cost-Share window

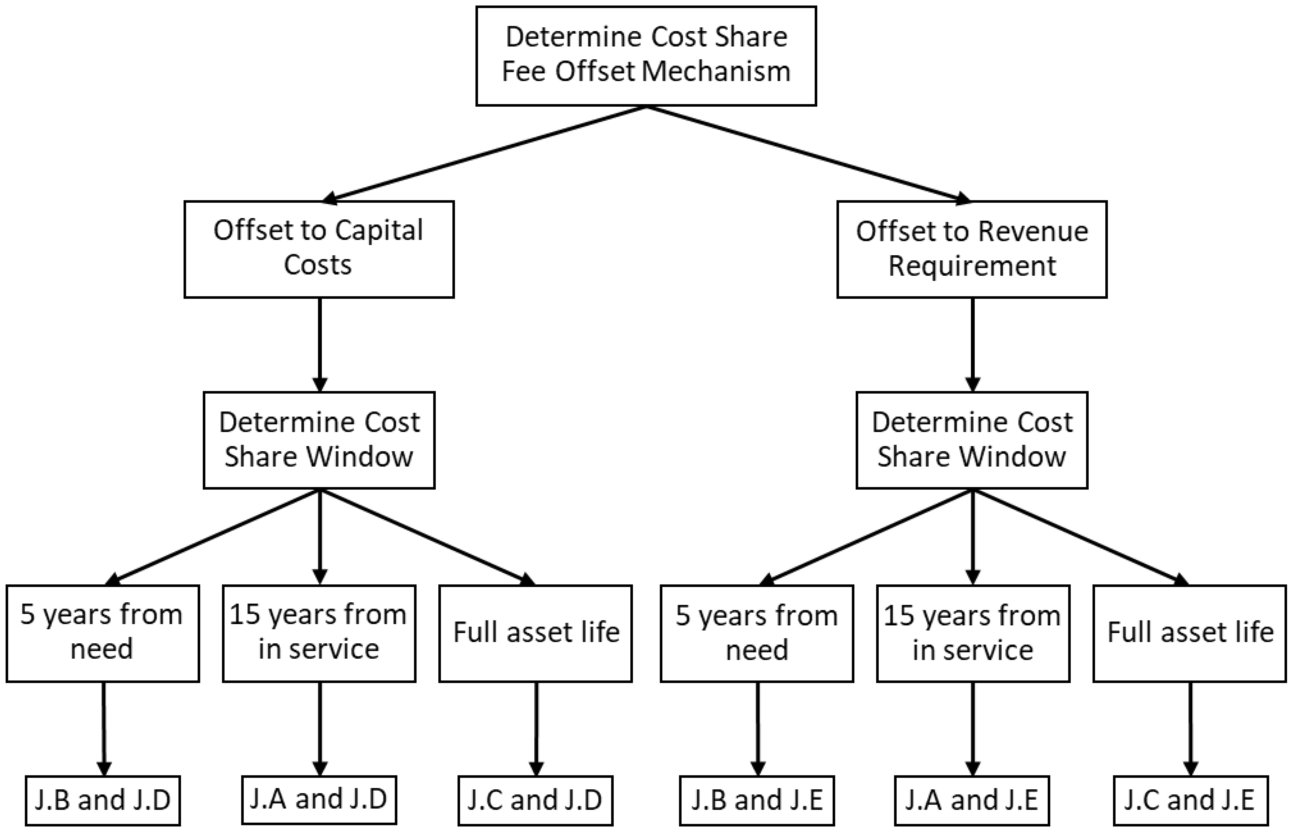
J.G At the end of the Cost-Share Window, any remaining costs that have not been offset by Proactive Cost-Share Fees are placed into rate base and no longer subject to this cost sharing program.

J.H Upon completion of a Proactive Distribution Upgrade Project, the total costs of the upgrade are placed into rate base.

J.I Interconnecting customers that apply to interconnect on or before the Proactive Cost-Share Window end date are Proactive Cost-Share Customers. For generation interconnections, the date of applying to interconnect shall be the Deemed Complete date under the Minnesota Distributed Energy Resource Interconnection Process (MN DIP).

Staff provides Figure 5 that describes the different paths available to the Commission under section J and which decision options it would adopt under each option.

Figure 5: Decision flowchart for Section J



Sections J.A, J.B, and J.C allow the Commission to decide on length of the cost share window. Under J.A or J.B the Commission may change the length of the cost share window if it wishes.

Supports J.A: ELPC/VS/CEF, MNSEIA, Fresh Energy, MP
Supports J.B: Xcel
Supports J.C: OAG, Department

Sections J.D and J.E allow the Commission to determine the treatment of cost share fees during the cost share window. Staff notes that there are multiple other subsections that also refer to the treatment of cost share fees. Staff recommends the Commission have a discussion and decide on the treatment of cost share fees in coordination with its decision on the length of the cost share window.

There are tradeoffs to either offsetting the capital costs or the revenue requirement of proactive upgrades with cost share fees.

In the short run, using cost share-fees to offset the revenue requirement would reduce rates for customers more than treating them as an offset to capital assets, but entails more long-term risk. Of the two options, offsetting the revenue requirement could result in higher rates in the long run if cost-share customers do not make up a larger percentage of new load and recovery is deferred. Additionally, because Xcel uses a forecast test year, specific large cost-share customers' contributions are unlikely to be returned to customers without a true-up mechanism. The forecast test year would include estimated cost-share customer revenues which may under or overestimate actual revenues. This would only be meaningful if this program becomes "large" – it requires variations on the order of $40-50 million to have a $1 per month effect on residential bills for Xcel.

Applying cost share fees as an offset to the capital costs of upgrade projects, rather than the revenue requirement, produces a greater reduction in rates for customers in the long run by reducing rate base, return on rate base, and long-run depreciation costs. This is similar to how CIAC works today. However, keeping the depreciation and rate base of the projects separate (if fees are assigned to offset the capital expenditures instead of revenues) is burdensome, both as a matter of accounting and on the ground. Administratively, this gets increasingly complicated the longer the cost share window lasts.

On the length of the cost share window, the longer the term, the more administratively burdensome tracking becomes. It is quite conceivable that a longer cost-share window would require tracking of rolling 30-to-40-year windows for proactive upgrade projects with vastly different per-kW costs. If there is no socialization of costs during a 15-year cost share window, the rate base value of proactive upgrades could more than double if few or no cost-share customers appear – for instance if load growth occurs primarily among small customers who are not subject to cost-share fees, or if larger cost-share customers do not appear. Inflation could also lead to lower-cost earlier projects being combined with higher-cost later projects during a long cost-share window, leading to inter-generational cost transfers.

Supports J.D: ELPC/VS/CEF, MNSEIA, Fresh Energy, MP
Supports J.E: Xcel

Sections J.F, J.G, and J.H describe when proactive upgrade project costs are placed into rate base. Because positions on this topic have shifted throughout the comments, Staff is unclear which of these options, if any, commenters believe are necessary. In particular, J.F and J.G appear to be in direct conflict with several of the cost share window options.

Finally, J.I is identical to J.9 and clarifies that any customer applying to interconnect on or before the end of the cost share window would be a cost share customer. Staff notes that ELPC/VS/CEF and MNSEIA opposed this provision, but did not provide justification. Staff believes that clearly establishing the end date of customer eligibility is important and the Commission should adopt J.I unless ELPC/VS/CEF or MNSEIA offers an alternative.

iii. Cost Cap

The OAG, Department, MNSEIA, ELPC/VS/CEF, and Fresh Energy supported the establishment of a cost-cap as a mechanism for ratepayer protection. Xcel and USC opposed a cost cap.

The OAG explained that as some portion of proactive distribution upgrades will be socialized, it is critical to establish a cost cap by adopting J.10 and J.11. The OAG explained that J.10 establishes the concept of a cost cap but leaves the specific amount to be determined with the Commission's first proactive upgrade proposal decision. According to the OAG, having more specific cost and scope information from the first proposal will allow the Commission to make a more informed decision and since it would be set by order, make it easier to revise the cap in future proceedings as necessary.[133] ELPC/VS/CEF similarly supported a cap, stating it would "help to protect ratepayers from excessive costs associated with proactive upgrades." They also recommending establishing the exact amount as part of the first Proactive Upgrade Proposal decision.[134]

The OAG also supported J.11, which allows the utility to offset proactive upgrade costs that count towards the cap with cost-share fees. The OAG explained this is reasonable because as "capital expenditures for proactive upgrades have been paid down by cost-share fees, they do not impact ratepayers and do not need to be considered in applying the cap." It noted this should incentivize Xcel to collect cost share fees to allow more room under the cost cap for new proactive investment.[135]

The OAG opposed J.12, remarking that if it is adopted with a short cost share-window, such as 5 years, it would render the cost cap "virtually meaningless." The OAG explained that if the cost share fees were less than forecasted during the cost-share window, it could result in a larger portion of the proactive upgrade costs being moved to base rates, socialized, and no longer counting towards the cost cap, which would increase overall rates. The cap would therefore not account for substantial ratepayer costs that were not offset by fees.[136] The Department similarly opposed J.12, stating that it would "allow funding to replenish without a Commission decision."[137]

ELPC/VS/CEF supported both J.11 and J.12, explain that "as a particular upgrade is effectively "paid off," through Cost-Share Fees and/or socialization at the end of its Cost-Share Window, its associated costs should no longer count against the cap," which would allow additional proactive upgrades over time.[138]

Xcel opposed the establishment of a cost cap, stating that it was unnecessary and potentially counterproductive. The Company explained that it will account for the costs of proactive upgrades in its existing capital planning process, which is overseen by the Commission. This allows for proactive upgrades to be evaluated alongside other investments and prioritized accordingly. With a cost cap Xcel believed it could lose flexibility to respond to "emerging needs, technological advancements, or evolving policy objectives" and potentially "discourage

[133] OAG, Initial Comments, p. 17-18
[134] ELPC/VS/CEF, Initial Comments, p. 8-9
[135] OAG, Initial Comments, p. 17-18
[136] OAG, Initial Comments, p. 17-18
[137] Department, Initial Comments, p. 6
[138] ELPC/VS/CEF, Initial Comments, p. 8-9

proactive investments that could ultimately reduce long-term costs, improve system resilience, or support clean energy integration." However, if a cost cap is adopted, Xcel emphasized the importance of adopting J.11 and J.12 which explain how a cost cap would function and "does not penalize utilities for leveraging cost-sharing mechanisms or for transitioning completed projects into system assets."[139]

Staff Analysis*:* Staff notes that establishing a cost cap intersects with the length of the cost share window. If a 15-year (J.5 and J.6) or indefinite (OAG/Dept.J.6) cost share window is adopted, adoption of J.12 will have less of an impact ratepayer risk, as the longer period for cost recovery fees will result in lower costs being socialized to ratepayers. In contrast, if a 5-year cost-share window (J.7) is adopted, there is the potential for higher overall program costs that will not be contained by the cost cap. A cost share cap is also contemplated in the reactive DER Cost Share process underway in Docket 24-288.

Supports J.10: OAG, Department, MNSEIA, ELPC/VS/CEF, Fresh Energy
Supports J.11: OAG, Department, MNSEIA, ELPC/VS/CEF, Fresh Energy (Xcel if J.10 adopted)
Supports J.12: MNSEIA, ELPC/VS/CEF, Fresh Energy (Xcel if J.10 adopted)

iv. Prudency Review

This section establishes the weight the Commission's decision on the Proactive Upgrade Proposal holds in a cost recovery proceeding.

The OAG, Department, ELPC/VS/CEF, Fresh Energy, UCS and CCSA, support J.13 and J.18, which establishes a rebuttable presumption of prudence for approve proactive upgrades. A rebuttal presumption of prudence means that costs associated with completed projects that are consistent with the Commission's proactive upgrade proposal decision are prudent, but an interested person may present evidence to rebut the prudency during a cost recovery proceeding.

The OAG explained that in this context, a rebuttable presumption of prudence can be compared to the approval process occurs in an IRP. Like the IRP, in a proactive upgrade proposal decision the Commission establishes the size, type, and timing for a certain type of upgrade based on the forecasted need. Unlike an IRP proceeding, a proactive upgrade decision also establishes the location and cost for the project. The OAG noted that as long as the utility performs the upgrade in line with the Commission's decision, there would not be grounds to find it imprudent. However, the OAG emphasized that it is important for the Commission to "not tie its hands in future cost recovery proceedings." In the OAG's estimation, J.13 with the addition of J.18, which requires any person seeking to rebut the Commission's decision to provide "substantial evidence," should provide a utility with reasonable certainty that it will receive rate recovery for its proactive upgrade investments.[140]

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[139] Xcel, Reply Comments, Attachment 1, p. 16
[140] OAG, Initial Comments, p. 18-19

The Department and ELPC/VS/CEF also recommended adoption of J.13 and J.18.[141] ELPC/VS/CEF explained that under a rebuttable presumption of prudence the utility would need to "provide evidence that its investment and related costs comport with what the Commission previously approved." While they acknowledged a utility may want the additional certainty an advanced determination of prudence would provide, in ELPC/VS/CEF's view this would create an unacceptable shift in risk to ratepayers.[142]

Xcel, MNSEIA, MP, and ATE support J.14-J.16, which establishes an advance determination of prudence for approved proactive upgrades. An advance determination of prudence means that costs that align with the Commission's proactive upgrade proposal decision cannot be deemed imprudent in a cost recovery proceeding.

Xcel explained it required the level of certainty an advance determination of prudence provides to proceed with proactive grid upgrade investments. The Company noted that utility accountability is provided by the requirement to execute the project as approved by the Commission and prove why any excess costs were prudently incurred. A rebuttable presumption, Xcel claimed, would not provide the necessary confidence for it to pursue the major infrastructure investments. Xcel outlined the following reasons for its support of J.14 through J.16:

- Predictability. An advance determination of prudence assures utilities that costs aligned with an approved proposal will be recoverable—critical for long-term planning, financial modeling, and securing support for capital-intensive projects.
- Reduces Regulatory Burden and Redundancy. Resolving prudence questions upfront streamlines the process by reducing duplicative review and the potential for contentious rate case proceedings later.
- Aligns with Broader Policy Goals. An advance determination of prudence supports the Commission's goals of grid modernization, distributed energy resource (DER) integration, and long-term planning by reducing financial and regulatory risk.
- Maintains Accountability. Oversight remains intact—only costs consistent with the approved scope are protected, and any material deviations remain subject to review and potential disallowance.[143]

Xcel also supported J.17 and J.19.

ATE similarly supported J.14 through J.16. ATE noted it did not support this lightly but given the extensive level of evaluation criteria in sections D through H, along with ratepayer protections under section J and K, it could support an advance determination of prudence for proactive upgrades. ATE explained that with the rigorous review and risk mitigation measures contemplated by the framework, the prudency of proactive upgrades would be sufficiently

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[141] Department, Initial Comments, p. 6
[142] ELPC/VS/CEF, Initial Comments, p. 9
[143] Xcel, Reply Comments, p. 2-3

evaluated ex ante to stand in for the traditional post hoc review. ATE also supported J.19, consistent with reason above.[144]

The OAG opposed establishing an advance determination of prudence and opposed J.17 and J.19. In justifying its opposition, the OAG explained:

> An "advance determination of prudence" does not exist in Minnesota law, and the Commission should not invent this regulatory concept where the Legislature has not acted to do so. An advance determination of prudence (ADP) is an attempt to tie the Commission's hands in a future ratemaking proceeding. But doing so is neither feasible nor good policy. First, an ADP is not feasible because the Commission cannot bind a future Commission's cost-recovery determination regarding proactive upgrades.[13] Moreover, even if the Commission could predetermine the prudence of not-yet-built projects, it should not do so because it would be unfair to ratepayers. There could be situations where it is imprudent to build an approved upgrade—for example, if there is a major change in need following the Commission's decision. For example, a proactive upgrade might be approved assuming commercial development would occur in a certain area. But if intervening events rendered commercial development at that location infeasible, it might be imprudent for Xcel to continue its planned proactive upgrade. It would not be fair for ratepayers to bear the cost of a project that Xcel knew or reasonably should have known was no longer needed, even if it had been found needed based on an earlier forecast.[145]

The OAG opposed J.17 and J.19 as it understood them to shift risk to ratepayers. are unnecessary and unreasonable because they attempt to shift risks from the utility to ratepayers. As the OAG understood it, J.17 would allow the utility to recover any spent funds, even if imprudent, as long as it occurred before a Commission decision rescinding a prior proactive upgrade approval. The OAG opposed J.19 for similar reasons, noting that a utility could stay within its approved budget, but still act imprudently, for example if there was a known change in forecast prior to initiating a project.[146]

CCSA objected to the establishment of an advance determination of prudency, stating that a rebuttable presumption "strikes an appropriate balance between utility assurance and ratepayer protection." CCSA worried that an advance determination of prudence could "undermine accountability, especially in a new and evolving program."[147]

Staff Analysis*:* Staff notes that Minnesota does not currently have a precedent for an "advance determination of prudence." While this concept exists in other states, this would be a new consideration in Minnesota. While Staff understands that utilities prefer certainty, that should

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[144] ATE, Reply Comments, p. 4-5
[145] OAG, Initial Comments, p. 18-20
[146] OAG, Initial Comments, p. 20
[147] CCSA, Reply Comments, p. 5

not come at the expense of ratepayers. Proactive grid upgrades are a new paradigm, and risk sharing between the utility and customers is reasonable.

If the Commission adopts J.13 and establishes a rebuttable presumption of prudence, Staff believes there could be an amendment to J.18 to alleviate some of the Company's concerns about retroactive prudency reviews. Specifically, Staff suggests that "substantial evidence" not include a change in forecasted need that occurs during or after the construction of an approved proactive upgrade.

Staff.J.18 An interested person may submit substantial evidence to rebut the Proactive Upgrade Proposal findings and conclusions in a cost recovery proceeding. Substantial evidence does not include a change in forecasted need that occurs after the utility has initiated construction of a proactive upgrade.

Staff suggests this amendment for several reasons. First, Staff believes that disallowing cost recovery based on a change in need that occurs after the utility has initiated construction is not reasonable as it would invite re-litigation of the Commission's decision in perpetuity. Second, overall Staff's understanding is that reevaluation of need for approved project should occur under C.6 or Xcel.C.6, which clearly outlines a process for a change in project scope. Finally, Staff uses "initiated construction" as it provides a clear decision point at which the utility begins to incur significant capital costs towards a proactive upgrade. Staff notes that its modification does not preclude interested persons from presenting other evidence of imprudence after construction occurs. It also would not preclude an interested person from presenting evidence that there was a known change in forecasted need *before* the utility initiated construction that would impact the overall scope of the project.

Supports J.13: OAG, Department, ELPC/VS/CEF, Fresh Energy, UCS, CCSA
Supports J.14-J.16: MNSEIA, Xcel, MP, ATE
Supports J.17: Fresh Energy, Xcel
Supports J.18: OAG, Department, MNSEIA, ELPC/VS/CEF, Fresh Energy, UCS, CCSA
Supports J.19: Xcel, ATE

Staff Alternative: Staff.J.18

K. Cost Allocation

As noted above, the Cost Recovery portion of the framework pertains to *how* cost recovery will be conducted, while this section, Cost Allocation, pertains to *who* bears the costs of proactive upgrades. MNSEIA, CEEM, and the OAG offered high level comments on how the Commission should approach Cost Allocation under the framework.

MNSEIA supported the equitable cost allocation of proactive upgrades between both new load and generation customers. It also noted that the Phase 1 proposal before the Commission did not address Xcel's Technical Planning Standard (TPS) which serves as a reliability buffer by limiting hosting capacity to 80% of a feeder's thermal rating, plus daytime minimum load. Because the TPS is framed as a benefit to distribution load customers, MNSEIA advocated for allocating the costs of a 20% reliability reserve to load customer and not interconnecting generation. As this topic was not addressed during Phase 1, MNSEIA request the Commission address it in Phase 2 of the proceeding (**Decision Option 6.e**).[148]

MNSEIA also advocated for waiving cost-share fees for small DER systems under 40kW in size, stating that smaller systems have less ability to absorb additional costs for infrastructure upgrades on the primary system, especially when they often need to also pay for secondary system upgrades. MNSEIA noted that Xcel's existing Small-DER cost share fund was created to pay for these secondary system upgrades and that using that fund to pay the cost-share fees for proactive upgrades could quickly exhaust the funds in the program. MNSEIA noted it had heard extensively from its members that develop under 40kW projects on this topic, all of whom emphasized the importance of maintaining the financial solvency of the small DER Cost Share program. Therefore, MNSEIA recommended that regardless of which method of cost allocation the Commission adopts under Section K, it exempt under 40kW customers from paying Cost Share Fees. Alternatively, if the Commission determines small DER customers should pay a cost fee, MNSEIA explained it members would rather see an additional flat $200 fee assessed to all under 40kW customers, regardless of whether they were interconnecting at a proactive upgrade. These extra funds could then be used to pay for the cost share fees of small DER customers in proactive upgrade locations.[149]

CEEM similarly recommended the Commission waive cost share fees for small DERs under 40kW in size. CEEM explained that a pro-rata cost share structure for small DERs could their interconnection fees cost prohibitive, which would slow clean energy development in Minnesota.[150]

The OAG did not take a position on any particular method of cost allocation from K.1 through K.19 but expressed that any cost share fees should be based on the number of kW of hosting capacity a customer is accessing and the cost per kW of that upgrade.[151]

i. K.1

The Department recommended adding the word retroactive to K.1, which it explained will ensure any changes in utility standards are not applied retroactively to completed projects.

Dep.K.1 If a change is made to distribution planning or other utility standards that impacts the amount of available hosting capacity after a proactive upgrade project has been completed, there shall be no resulting retroactive change in cost-sharing responsibility.

Xcel stated it did not oppose the Department's modification[152] and no other commenters weighed in on the matter. Staff recommends adoption of Dept.K.1.

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[148] MNSEIA, Initial Comments, p. 7spici
[149] MNSEIA, Initial Comments, p. 7-8
[150] CEEM, Reply Comments, p. 4-5
[151] OAG, Initial Comments, p. 20
[152] Xcel, Reply Comments, Attachment 1, p. 18

Supports K.1 or Dept.K.1: Department, ELPC/VS/CEF, Fresh Energy, Xcel, MP

ii. K.2 – K.6

Xcel, MNSEIA, ELPC/VS/CEF and Fresh Energy supported K.2 through K.6. Under this proposal a single fee would be established for the entire proactive upgrade program based on the total cost of all upgrades divided by the total capacity gained (K.2). Cost share fees would either be used as an offset to the capital costs of all proactive upgrades (K.2) or as an offset to the revenue requirement of all proactive upgrades with an open cost share window (Xcel.K.2). The fee would be recalculated when new proactive upgrade projects are approved (K.3) The cost share fee would be charged to interconnecting DER customers that are not subject to Xcel's Priority Queue (K.4) and all demand metered load customers (K.5). Costs socialized to ratepayers would be allocated consistent with approved rate case allocators and revenue requirement procedures (K.6).

Xcel proposed a modification to K.2 which no stakeholders responded to in reply comments:

Xcel.K.2 A $/kW$_{ac}$ fee shall be charged to any Cost-Share Customers and the dollars returned to ratepayers. The fee shall be calculated at an aggregated, programmatic level for all approved proactive upgrade investments. The fee calculation shall be the total cost of all approved Proactive Distribution Upgrades ~~-~~divided by the total kWac of capacity added by all approved Proactive Distribution Upgrades. This fee shall determine the pro rata cost for any Cost-Share Customer, load or generation, which will be applied as an offset to ~~and pay down the assets until~~ the total revenue requirements of all Proactive Distribution Upgrade projects ~~has been paid off~~ with an open cost share window.

Under Xcel's modification cost share fees would be applied as an offset to the revenue requirement of all proactive distribution upgrades with an open cost share window, instead of being applied to pay down the cost of the assets. Staff notes that while there were no objections to Xcel's modification to K.2 in reply comments, in initial comments on Section J the OAG objected to cost share fees being an offset to the revenue requirement rather than the remaining asset balance.

Xcel emphasized that K.2 through K.6 continue to treat the distribution system as an integrated whole that benefits all customers, rather than trying to parse out the benefits of individual upgrades as contemplated in K.7 through K.20.[153]

Fresh Energy supported both K.2 and K.6. Fresh Energy explained that under K.2 interconnecting customers are charged a fee which acts as an offset to ratebase. This aligned with its comments in the 2023 IDP, which initiated the instant proceeding. Fresh Energy explained that coupling a pro-rata fee with proactive upgrades provides ratepayer protection to customers who do not directly benefit from an upgrade by reducing the costs recovered from

[153] Xcel, Reply Comments, Attachment 1, p. 20

all ratepayers.[154] Fresh Energy also supported K.6, explaining that is ensures costs are appropriately socialized across customer classes which will support overall electrification and DER adoption.[155]

ELPC/VS/CEF likewise supported K.2 – K.6, stating that it is an "administratively reasonable approach to cost allocation." It emphasized sections K.4 and K5 as particularly important, as they would exempt the vast majority of residential and small commercial customers from cost sharing fees and allow those costs to be socialized. In ELPC/VS/CEF's view, socialization of upgrade costs for this subset of customers will encourage greater adoption of DERs and electrification in line with Minnesota policy goals. ELPC/VS/CEF also supported K.2, which they stated, "appropriately balances the cost-causer pays principle with establishing a system that is not overly burdensome for the utility to administer." While they acknowledged this approach fails to drive DER development towards lower cost options, they stated it provides a starting point for Phase 1 that can be reevaluated during Phase 2.[156]

***Staff Analysis*:** K.2 through K.6 proposes to calculate cost share fees and recover/allocate upgrade costs at a program level, rather than developing individual fees and cost allocation methodologies for individual projects. It also proposes to treat generation and load customers interconnecting at a location with a proactive upgrade in the same manner.

K.2 and Xcel.K.2 are identical aside from how they propose to use cost-share fees to offset proactive upgrade costs. As Staff recommends determining the treatment of cost-share fees in conjunction with the determination of the cost share window, it recommends striking the last clause as it would be duplicative of whatever provision is adopted in section J. The stricken section is reflected in J.A and J.B. Staff's revision focuses K.2 solely on how the cost-share fee shall be calculated but does not otherwise change the decision option. Therefore, if the Commission wishes to adopt this package, Staff recommends adoption of Staff.K.2 and K.3-K.6.

<u>Supports K.2</u>: MNSEIA, ELPC/VS/CEF, Fresh Energy
<u>Supports Xcel.K.2</u>: Xcel
<u>Supports K.3-K.6</u>: MNSEIA, ELPC/VS/CEF, Fresh Energy, Xcel

Staff alternative: Staff.K.2

iii. <u>K.7 – K.12</u>

The Department supported K.17 through K.12 as the method of cost allocation, which it proposed during the workgroup process. Under the Department's proposal, each proactive upgrade would be tracked individually, rather than as a group as proposed under K.2 through K.6. The exact cost allocation methodology would be determined based on the forecasted need

[154] Fresh Energy, Initial Comments, p. 7
[155] Fresh Energy, Initial Comments, p. 7
[156] ECLP/VS/CEF, Initial Comments, p. 9-10

and customer classes expected to use the upgrade. Cost share fees would be calculated for each proactive upgrade and used to pay down that particular asset.[157]

The Department proposed minor revisions to K.7, K.8, and K.10. Subsections K.7 and K.10 were revised to replace CIAC with the definition of "cost share fee" to align with the rest of the Framework. K.8. was modified to simplify the language pertaining to allocating the costs of commercial and industrial-driven upgrades specifically to those classes.[158]

As the Department was the only stakeholder to support K.7 through K.12 and its proposed edits to the subsections were technical in nature, Staff incorporated the changes described above into the framework without creating new alternatives to reduce the number of options for the Commission.

The OAG noted support for K.12, but pointed out it may be duplicative of J.4, which the OAG also supports. The OAG understood K.12 and J.4 to state that cost share fees received by the utility will act as an offset to the cost of the asset in ratebase.[159]

Xcel opposed K.7 through K.12 for the following reasons:

1. Departure from Established Cost Allocation Practices. K.7–K.12 replace standard use of rate-case-approved-allocators with ad hoc, project-specific fees that fragment cost recovery and reduce regulatory consistency.
2. Mischaracterization of Upgrade Benefits. Classifying upgrades as serving either load growth or generation interconnection ignores that most upgrades support both, leading to unfair and inaccurate cost allocations.
3. Risk of Discouraging Investment. By shifting financial risk to specific customer groups, these provisions may discourage utilities from pursuing needed upgrades—slowing progress on electrification and grid modernization.
4. Redundant Revenue Return Mechanisms. K.10 and K.12 duplicate existing ratemaking processes for returning cost-share revenues to ratepayers, adding complexity without improving protections.
5. Dynamic Nature of the Distribution System. The distribution system evolves, often changing which customers benefit from a given upgrade. Basing cost allocation on initial conditions risks long-term misalignment and inequity.[160]

The Company strongly recommended rejection of K.7 through K.12 in favor of K.2-K.6, which it explained were "consistent, industry standard, established methods used to recover all other infrastructure investments whether it be in rate cases or riders."[161]

[157] Department, Initial Comments, p. 6, Draft Framework, Subsections K.7 through K.12
[158] Department, Initial Comments, p. 6
[159] OAG, Initial Comments, p. 22-23
[160] Xcel, Reply Comments, p. 3 and Attachment 1, p. 20-21
[161] Xcel, Reply Comments, p. 3

Staff Analysis: Like with Staff's revision of K.2, Staff suggests the Commission not adopt K.10 or K.12 as those provisions are reflected in J.D and J.E.

K.7 through K.12 propose to separately calculate cost share fees and create customer allocators based on the expected customer makeup of each proactive upgrade. This would include differentiation of upgrades and cost-share fees based on whether they were primarily serving load or generation.

<u>Supports K.7-K.12</u>: Department
<u>Supports K.12</u>: OAG

iv. <u>K.13 – K.19 and K.20</u>

While K.13 through K.19 were discussed in the workgroup meetings, no commenter supported any of the provisions in comments.

MNSEIA indicated support for K.20, but did not provide a rationale for its support. MNSEIA also supported K.2 through K.6.

Xcel opposed K.12 to K.19 and K.20 for the same reasons it opposed K.7 through K.12.

v. <u>K.21 – K.26</u>

While K.21 was included in the draft framework, no organizations support it in comments. Therefore, Staff does not recommend adoption.

The OAG supported K.22, which deems projects associated with identifiable customers ineligible for the proactive process. The OAG explained it would not be fair to socialize the costs of upgrades that serve large commercial and industrial customers as those upgrades are likely to be expensive and not have widespread benefits beyond the customer they serve. The OAG gave a data center as an example, stating it would be unfair to have small commercial and residential customers bear the risk for the upgrade. Instead, the OAG recommended that a utility work with that specific customer to meet their distribution needs and allocate costs under existing CIAC policies.[162] Xcel opposed K.22, stating that it would be inconsistent with the purposed of the draft framework. The Company sympathized with the OAG's concerns but explained that the framework is "designed to address system needs that fall outside the traditional five-year planning window. It is unclear why upgrades tied to forecasted needs—even if associated with identifiable customers—should be excluded from eligibility under this process."[163]

Fresh Energy supported K.23, which clarifies that Xcel's existing CIAC waiver for residential customers who enroll in the Company's EV managed charging rates would still apply under the draft framework. Fresh Energy requested that any changes to this policy occur through the

[162] OAG, Initial Comments, p. 21
[163] Xcel, Reply Comments, Attachment 1, p. 22

utility's Transportation Electrification Plan.[164] Xcel opposed K.23, explaining that it was redundant with other framework provisions, such as cost allocation principles in Section A.[165]

The OAG, Department, and ACEEE supported K.24 and K.25 which specify that upgrades intended to serve residential and small commercial would use traditional cost allocations methods and approved cost allocators, while upgrades that primarily serve large commercial and industrial customers would be separately tracked and allocated to the customer classes causing the need. ACEEE explained that K.24 and K.25 will ensure that "upgrades brought about by larger loads from industrial and commercial customers are not misattributed to residential customers."[166] The OAG supported K.24 as upgrades service residential and small commercial customers are "likely to be similar in nature to standard distribution investments, be modest in cost, and have widely distributed benefits, making traditional cost-allocation methods fair."[167] The OAG proposed a modification to K.25 that would require separate tracking and cost allocation for upgrades serving large C&I customers:

OAG.K.25 For upgrades primarily serving large commercial and industrial customers, proactive upgrades shall be tracked separately from other rate-base assets and ~~their total cost~~ allocated ~~based on customer classes' aggregate contribution to the need for proactive upgrades~~ to the large commercial and industrial classes contributing to the need for or benefiting from the upgrades.[168]

Xcel opposed K.24 for the same reason it opposed K.23, stating that it was redundant with other provisions in the framework. It also opposed the original K.25 and OAG.K.25 for the following reasons:

- The distribution system is inherently dynamic. It serves a mix of customer classes at nearly every location. Even if a feeder or substation primarily serves large commercial or industrial customers today, that can change over time due to new developments, shifting load patterns, or system reconfigurations.
- Upgrades benefit multiple classes. Proactive upgrades typically increase capacity and flexibility for all customers served by the affected infrastructure—not just one class.
- Utility cost allocation is imperfect but rigorous. Utility cost allocation is a rigorous process that relies on industry standard methodologies. However, allocation of costs to cost causers and beneficiaries is an imperfect science, and some level of cross-subsidization reasonably occurs and is acceptable. There is no reason for proactive upgrades to be treated differently than other utility infrastructure investment costs.[169]

The OAG, Department, MNSEIA, ACEEE, and Fresh Energy supported either K.26 or OAG/Dept.K.26, which would require Xcel to mitigate adverse bill impacts resulting from the

[164] Fresh Energy, Initial Comments, p. 6
[165] Xcel, Reply Comments, Attachment 1, p. 22
[166] ACEEE, Initial Comments, p. 4
[167] OAG, Initial Comments, p. 20-21
[168] OAG, Initial Comments, p. 20-21
[169] Xcel, Reply Comments, Attachment 1, p. 23

proactive upgrade program. The OAG and Department recommended striking the last clause of K.26 to grant additional flexibility for the Company to use to mitigate adverse bill impacts.[170] The OAG explained it supports OAG.K.26 because "Under-resourced customers are less likely to be able to participate in the energy transition through end uses like electric vehicles, rooftop solar, and electric space heating, making it potentially unfair for them to bear the same share of proactive upgrade costs as customers that can participate fully in these end uses."[171] ACEEE and Fresh Energy both emphasized the importance of alleviating cost impacts from the program for under resourced customers so they can benefit from proactive upgrades.[172]

ELPC/VS/CEF did not support adoption of K.21-K.25, stating that K.2-K.6 sufficiently cover cost allocation, and the subsections would be potentially duplicative. Regarding K.26, ELPC/VS/CEF supported the intent, but were concerned that it would not be implementable in practice. Instead, they suggested further discussion in Phase 2 to see if there were other options to provide additional protections to low-income ratepayers. ELPC/VS/CEF noted that existing provisions in the framework allow the Commission and stakeholders to track the impacts of the program on Environmental Justice Areas of Concern, along with robust reporting requirements.[173]

Xcel concurred with ELPC/VS/CEF on the feasibility of implementing K.26. The Company stated that while it wholeheartedly supports affordability considerations, that is best considered under the site evaluation criteria, specifically G.10, which discusses customer bill impacts. The Company supported addressing affordability concerns through complementary regulatory programs.[174]

Staff Analysis*:* Regarding K.23, Staff notes that the Company's existing CIAC waiver for residential electric vehicle customers concerns smaller service transformers that are on the secondary system, and not the larger primary system upgrades that are contemplated under the draft framework. Staff does not believe it is necessary to specifically call out this program in the framework as it is does not pertain to issues at hand in the framework.

Staff concurs with ELPC/VS/CEF that K.24 and K.25 are duplicative of other subsections of the framework, specifically K.24 is nearly identical to K.9, while K.25 and K.8 are substantively similar. If the Commission adopts K.2-K.6, adoption of K.24 and K.25 would be in direct conflict with those provisions. Therefore, Staff does not recommend adoption of K.24 and K.25 for technical reasons.

On K.26, Staff echoes the concern about feasibility raised by ELPC/VS/CEF and Xcel. As written, K.26 leaves out key details such as which customers would qualify as "under resourced" and whether ratepayers or interconnecting customers should pick up the tab. If the Commission is

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[170] Department, Initial Comments, p. 6
[171] OAG, Initial Comments, p. 21-22
[172] ACEEE, Initial Comments, p. 4; Fresh Energy, Initial Comments, p. 7
[173] ELPC/VS/CEF, Initial Comments, p. 10
[174] Xcel, Reply Comments, p. 23-24

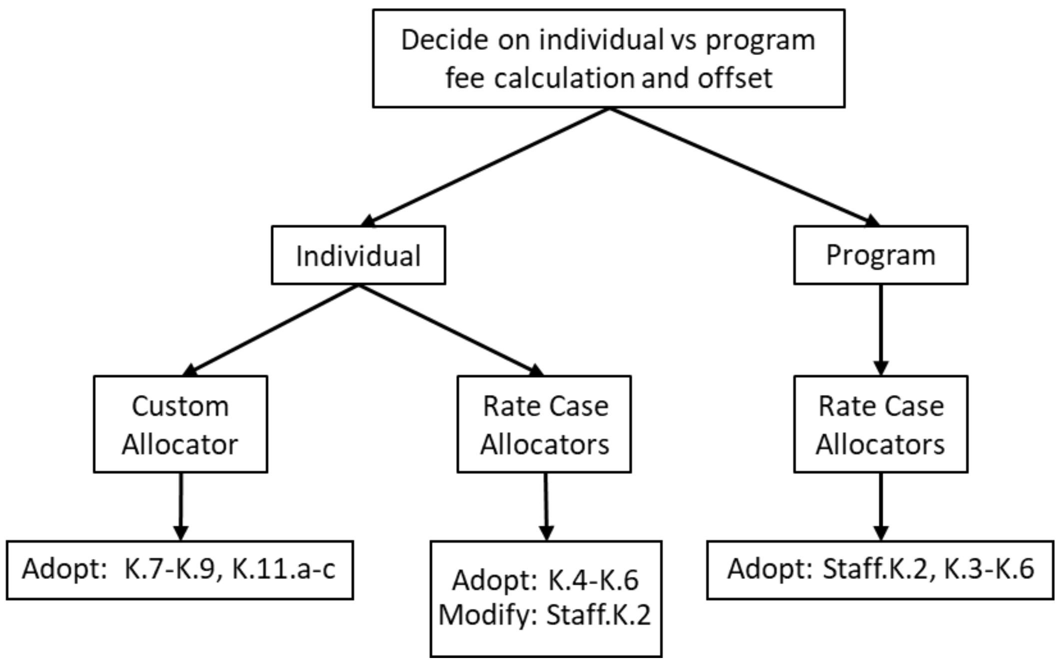
interested in this provision, Staff agrees with ELPC/VS/CEF's recommendation to discuss the matter further during Phase 2.

Supports K.21: n/a
Supports K.22: OAG, MNSEIA
Supports K.23: MNSEIA, Fresh Energy
Supports K.24: OAG, MNSEIA, ACEEE
Supports K.25: MNSEIA, ACEEE
Supports OAG/Dept.K.25: OAG
Supports K.26: MNSEIA, Fresh Energy, ACEEE
Supports OAG/Dept.K.26: OAG, Department

vi. Staff Analysis:

Staff provides the following flow chart in Figure 6 to indicate the pathways available to the Commission for how costs should be tracked and allocated.

Figure 6: Decision Flow Chart on Cost Allocation



If the Commission decides to track upgrade costs at the program level, rate case allocators would apply and subsections Staff.K.2 and K.3-K.6 should be adopted. This is the preferred approach of Xcel, ELPC/VS/CEF, MNSEIA, and Fresh Energy.

If the Commission would like to track upgrade costs at an individual project level, it may choose to either use rate case allocators for each individual project or create custom allocators for each project depending on its project attributes.

No organization advocated for tracking costs individually for each project and solely using rate case allocators, however if this is the Commission's preferred approach it could modify Staff.K.2 to refer to individual projects instead of a program level.

If the Commission would like to track costs individually for each project and create custom allocators, it may adopt K.7-K.9 and K.11 and all its subparts. This is the preferred path of the Department.

The Commission may select any of the above options with any length of cost share window or method of fee offset from a technical standpoint.

As noted above, Staff recommends either removing the entire decision options or the sections of decision options related to how cost share fees should be treated and deciding that under Section J. Staff's intent was to allow the Commission flexibility to choose decisions ala carte instead of needing to modify or create numerous new subsections.

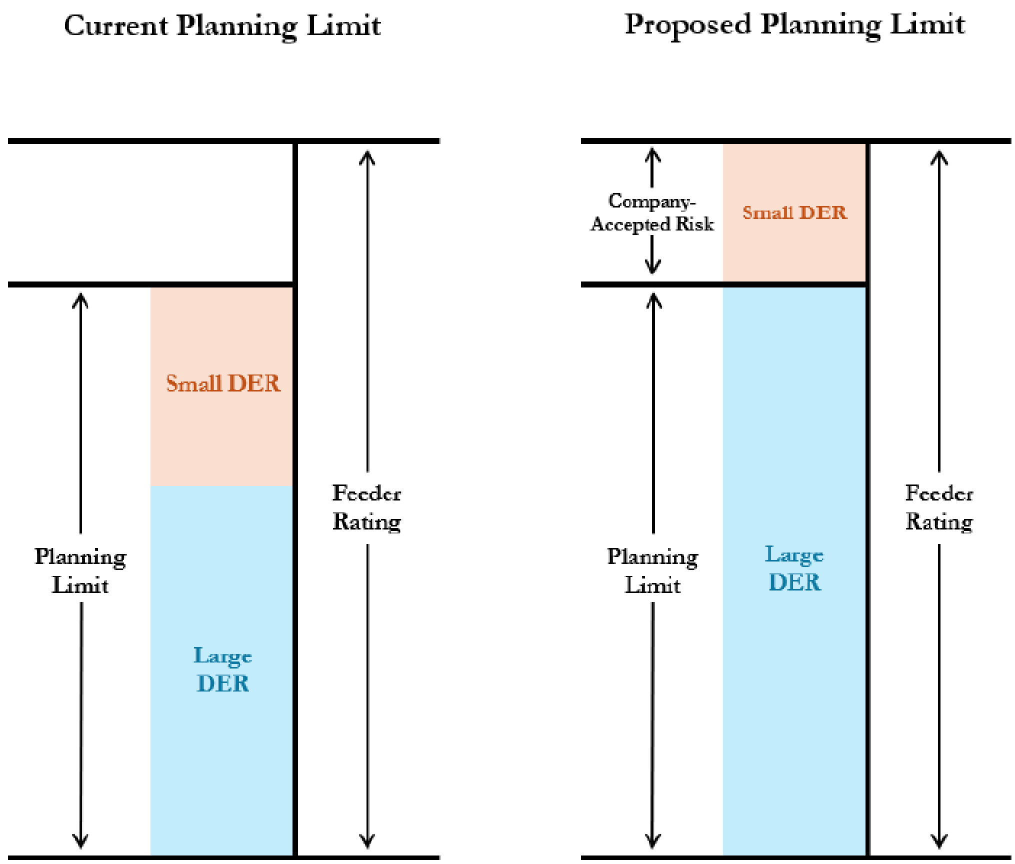
L. Capacity Reservation

Section L discusses whether Xcel should establish a capacity reservation system for proactive upgrades. A capacity reservation would hold a portion of the hosting capacity gained from a proactive upgrade for a certain customer class. The Commission has discussed the concept of a capacity reservation for Xcel Energy previously in the context of long wait times for residential and small commercial solar customers seeking to interconnect to the grid. During the workgroup process stakeholder suggested multiple paths for a capacity reservation, which are explained in L.1 through L.6. However, in comments only Xcel and Fresh Energy supported establishing a capacity reservation in Phase 1 while other stakeholders recommended further discussion of the merits of various options in Phase 2.

Xcel recommended adoption of its preferred capacity reservation system encompassed in L.4 and L.4.a. Under the Company's proposal, it would modify its existing Technical Planning Standard (TPS) to allow distributed generation that qualifies for its Priority Queue[175] to exceed the existing TPS up to the distribution equipment's thermal rating.[176] This change is depicted in Figure 7.

[175] DERs under 40 kW in size, plus DERs enrolled in Solar for Schools and Solar for Public Buildings
[176] Xcel Energy, Initial Comments, p. 4

Figure 7: Planning Limit Comparison



The Company explained that while exceeding the planning limit creates risks to the distribution system, when this exceedance is limited to small DERs that are associated with localized load it mitigates a portion of the impacts. The Company also explained this would be a temporary state, as under both the Proactive Distribution Upgrade Program and the forthcoming Reactive Cost Share Program, the Company would have mechanisms to remedy the situation. Xcel outlined the following benefits to its proposed capacity reservation:

- *Support for Small DER:* This would provide capacity for small DER to interconnect in areas where larger DER developers, such as Community Solar Gardens (CSGs), are active and have consumed the currently available capacity. This helps ensure that our smaller, particularly residential, customers can install rooftop solar without triggering costly upgrades.
- *Streamlined Processing:* Our proposed capacity reservation allows more streamlined processing of small DER applications through the recently implemented Priority Queue. The Company prioritizes DER applications in the Priority Queue over those in the General Queue. Once a feeder's planning limit is reached, the proposed capacity reservation would enable continued interconnection of small DER applications.
- *Facilitating Larger DER Projects:* With small DER applications continuing to move forward after the planning limit is reached, larger DER applications in the General Queue

could proceed with System Impact Studies, pursue a cluster study, or DER cost sharing (through the future Reactive cost sharing framework), which small DER applications typically cannot afford.[177]

Xcel noted that if the Commission does not approve L.4 or L.4.a, it supports adoption of L.1 which would not approve a capacity reservation system for the Proactive Grid Upgrade Framework. Company did not support L.2, L.3, or L.6 for the following reasons:

- L.2: Reserving capacity on the distribution system based on how costs are allocated does not necessarily align with the customer needs of that part of the distribution system.
- L.3: We do not support uniquely calculating a capacity reservation for each feeder. This will be difficult and burdensome to administer and track and will further complicate the interconnection process for customers.
- L.6: Specifying a 1 MW capacity reservation is arbitrary and may be too much or too little depending on the rated capacity of the feeder or substation transformer. The capacity reservation should align with the planning standard. The Company has a statutory obligation to serve load customers and there is no need for a capacity reservation for load customers.[178]

Fresh Energy cautioned against adopting "poorly applied" capacity reservations that could hinder near term DER adoption, but did support the concept to ensure equitable access to proactive upgrades. It explained that in general generation situation with load should have priority to access proactive upgrades over front of the meter generation, as it does not support socialization of costs that solely enable large front-of-the-meter (FTM) projects.[179] In reply comments, Fresh Energy supported Xcel's proposal under L.4 and L.4.a, stating that the modification of its TPS would effectively reserve capacity for small DER customers. This approach addressed Fresh Energy's main concerns: that small DERs are able to access proactive upgrades, and that there is equal access for all resources until the existing planning limit is reached. Therefore, Fresh Energy recommended adopting Xcel's capacity reservation proposal during Phase 1 to ensure the capacity created during initial proactive upgrade proposals is not subsumed by large DG. It also supported further refinement of the capacity reservation during Phase 2.[180]

ELPC/VS/CEF did not believe a capacity reservation was necessary if the Commission adopts K.2-K.6. As only larger customers would pay a cost share fee under K.2-K.6, ELPC/VS/CEF explained residential and small commercial customers would not be paying for upgrades that only larger customers utilize. However, they did recommend further discussion of capacity reservations in Phase 2 which would be informed the framework implementation.[181]

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[177] Xcel, Initial Comments, p. 4-5
[178] Xcel, Initial Comments, Attachment 3, p. 6
[179] Fresh Energy, Initial Comments, p. 5-6
[180] Fresh Energy, Reply Comments, p. 1-2
[181] ELPC/VS/CEF, Initial Comments, p. 10

The OAG and Department both recommended moving consideration of capacity reservations to phase two due to the large number of competing options.[182]

MNSEIA supported a capacity reservation in certain instances where one would be useful and based on the customers it serves. It did not support a blanket capacity reservation that was unilateral across the system and advocated for matching a capacity reservation to specific upgrades to avoid unused hosting capacity.[183] In reply comments, MNSEIA reiterated its support for a carefully tailored capacity reservation, but advocated for further development during Phase 2 of the proceeding due to the exclusion of FTM generation from Phase 1 of the framework and the wide ranging set of options captured under L.1 to L.6.[184]

CEEM similarly supported moving consideration of capacity reservations to Phase 2 so there can be equal consideration of front-of-the-meter generation as it is added to the framework.[185]

<u>Supports L.1</u>: ELPC/VS/CEF, MP
<u>Supports L.4 and subparts</u>: Xcel, Fresh Energy
<u>Recommends moving to Phase 2</u>: OAG, Department, MNSEIA, CEEM (ELPC/VS/CEF and Fresh Energy support further discussion, but also prefer adoption of subsections in Phase 1)

M. Reporting

Sections M.1, M.4, M.5, M.6, M.7, M.8, M.9, and M.10 are unopposed and may be adopted with **Decision Option 3.**

All commenters supported robust reporting requirements as outlined in section M. As noted by Fresh Energy, "reporting will be an essential tool to help stakeholders and the Commission evaluate whether the framework is functioning as intended."[186]

M.2 and M.3 are alternatives and concern reporting on individual upgrades after the cost-share window has closed. M.2 would discontinue all reporting, including aggregate reporting, for projects with a closed cost share window. M.3 would only discontinue individual project reporting under M.5 and M.6. Stakeholders universally supported M.3, with the OAG explaining

> If the Commission adopts M.2, it would eventually lose insight into the aggregate impacts of all proactive upgrade projects because, once upgrades' cost-share windows begin to close, they would be removed from the reported statistics.[187]

UCS supported the proposed reporting requirements but noted that under M.6 "electrified end uses" are not captured as an individual category. While it did not recommend a modification for the initial iteration of framework reporting, it noted that in the future it may be necessary to

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[182] OAG, Initial Comments, p. 23; Department, Initial Comments, p. 12-13
[183] MNSEIA, Initial Comments, p. 9
[184] MNSEIA, Reply Comments, p. 3-4
[185] CEEM, Reply Comments, p. 5
[186] Fresh Energy, Initial, p. 7
[187] OAG, Initial Comments, p. 23

update the table to include electrified end uses, especially for technologies like vehicle-to-grid (V2G) that could be both load and generation on the system.[188]

Xcel opposed M.11, stating that it would likely apply to every upgrade project as forecasting over a 10–15-year horizon will always involve some degree of error. Instead, Xcel supported its modified M.12.[189]

Xcel proposed a modification for M.12 which would strike the final portion of the requirement that outlines what impacts the utility should discuss:

> For projects that were accelerated, delayed, or abandoned following Commission approval, Xcel Energy shall discuss the impact of ~~that~~ the change ~~on total proactive grid upgrade costs, cost allocation, and benefit allocation~~.[190]

ELPC/VS/CEF objected to Xcel's modification, stating that including the specific types of impacts in the reporting requirement provides "valuable clarity." To provide Xcel flexibility however, ELPC/VS/CEF supported adding the words "if any" to M.12 which would allow the Company to only respond to impacted criteria.

> ELPC/VS/CEF.M.12: For projects that were accelerated, delayed, or abandoned following Commission approval, Xcel Energy shall discuss the impact of that change, including the impact, if any, on total proactive grid upgrade costs, cost allocation, and benefit allocation.[191]

Staff Analysis: Staff supports adoption of Section M and agrees with stakeholders that M.3 is preferable to M.2.

Regarding M.11, Staff notes that if the Commission does not adopt a cost share window under Section J.ii, M.11 would not be necessary. If the Commission adopts a cost share window with a finite length, Staff agrees with Xcel that M.11 may not result in useful information due to the inherent nature of forecasts. Staff is unclear what explanation would exist beyond "the forecasted load and/or generation did not materialize within the expected timeframe." Staff believes M.8 better captures the comparison of actual load/generation adoption to the forecast and will provide the necessary information for evaluation of the accuracy of Xcel's forecast methodology.

Staff supports ELPC/VS/CEF's modification to M.12 and agrees that including the list of impacts is useful.

Supports M.3: OAG, Department, ELPC/VS/CEF, Fresh Energy, UCS, Xcel, MP
Supports M.11: OAG, Department, MNSEIA, ELPC/VS/CEF, Fresh Energy, UCS
Supports M.12: OAG, Department, MNSEIA, ELPC/VS/CEF, Fresh Energy, UCS
Supports Xcel.M.12: Xcel

[188] UCS, Initial Comments, p. 3
[189] Xcel, Reply Comments, Attachment 1, p. 27-28
[190] Xcel, Initial Comments, Attachment 3, p. 6
[191] ELPC/VS/CEF, Reply Comments, p. 7-8

6. Additional Topics Raised

Stakeholders raised additional considerations related to the framework through their comments.

i. New IDP Filing Requirement

The Department noted that the Framework is voluntary, which means there is a potential for Xcel to not submit a proactive upgrade proposal. The Department expressed skepticism of proactive upgrades but acknowledged if a utility is expecting large load or DER growth, there are benefits to right-sizing the distribution system to avoid multiple rounds of upgrades. Therefore, the Department recommended that utilities evaluate their system for proactive upgrades as part of their IDP filing, and recommended including subsection E.4 as a new filing requirement in all utility IDPs:

> Forecast results for generation and peak loads at the feeder/substation level for all locations that have a potential proactive upgrade need, as well as the standard reactive upgrade capacity upgrade.[192]

ELPC/VS/CEF agreed with the Department that visibility into the utility's forecasting results regardless of whether it files a proactive upgrade proposal would be valuable and assist with understanding whether there are any missed opportunities for proactive upgrades. It therefore supported the Department's recommendation to add a new filing requirement, but recommended it be limited to utilities who have an approved proactive upgrade framework.[193]

Xcel opposed the Department's recommendation, stating it believes proactive upgrades should be optional, not mandatory. It reiterated that utilities should be the ones to propose upgrades as they are fully aware of all system conditions and mitigating factors. The Company outlined the following rationale for rejecting the Department's recommendation:

1. Existing Forecasting Is Sufficient. Utilities already provide detailed, stakeholder reviewed forecasts in their IDPs. Adding duplicative requirements would not improve transparency and could introduce confusion.
2. Forecast Uncertainty. Feeder-level forecasts are sometimes too uncertain to justify investment. Publishing them without action could mislead stakeholders and create false expectations.
3. Transparency Already Addressed. The draft framework already requires utilities to disclose which locations were considered and why upgrades were not proposed—striking a practical balance.
4. Added Burden Without Clear Benefit. Preparing detailed forecasts for nonactionable locations would divert resources from higher-value planning, with little added value for stakeholders or regulators.

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[192] Department, Initial Comments, p. 13-14
[193] ELPC/VS/CEF, Initial Comments, p. 11-12

5. Need for Flexibility. Effective proactive planning depends on utility discretion to focus on high-confidence, high-impact opportunities. A one-size-fits-all mandate would reduce efficiency and responsiveness.[194]

Staff Analysis: First, Staff notes that as this is an Xcel specific docket, the Commission would only be able to act on the Department's recommendation for Xcel, and not the other Minnesota utilities. Second, to Staff's knowledge, only Xcel is using an advanced forecasting tool like LoadSEER to create feeder and substation level forecasts beyond the typical utility planning horizon. Requiring other utilities to provide this level of detail would likely require them to invest in new forecasting software. When the Commission approved Xcel's request for LoadSEER, the initial cost was $9.3 million in capital expenditures. Currently Xcel files the results of its LoadSEER analysis with its integrated distribution plan. Staff believes a conversation about whether the current level of detail provided in the IDP is sufficient would be better had as part of the IDP proceeding, rather than as part of the proactive upgrade framework. Staff also notes this would also give the Commission and stakeholders the opportunity to see Xcel's initial Proactive Upgrade Proposal prior to establishing additional filing requirements in the IDP. Therefore, Staff does not recommend adoption of the new requirement at this time, and instead believes additional discussion would be useful.

Decision Option 9 would amend Xcel Energy's filing requirements.

ii. Overlap Between Proactive and Reactive Processes

The Department also expressed a concern about the overlap between the Proactive Framework and the Reactive Cost Sharing Program currently under development in Docket 24-288. Under the reactive process a certain portion of an upgrade's costs must be pre-paid by distributed generation facilities prior to beginning construction. The Department claimed that the portion that is not prepaid before construction is a "proactive" upgrade as it exists before there are established commitments to use the capacity. The Department explained that since asset upgrades are at least partially pre-paid under the Reactive Process, it prefers to use that framework whenever possible to minimize ratepayer impacts. It acknowledged that there may be some instances where the Proactive Framework can provide solutions, the default position should be to propose projects that upgrade for DER capacity through the reactive process. Therefore, The Department recommended that utilities be required to justify why all distributed energy resource projects proposed under the Proactive Upgrade Framework cannot be pursued within the Reactive Framework.[195]

Xcel opposed the Department's recommendation, stating the following concerns:

1. *Proactive and Reactive Frameworks Serve Distinct Purposes*. The Proactive Distribution Grid Upgrades Framework is designed to address anticipated grid needs in advance of DER interconnection requests, enabling more efficient, cost effective, and equitable integration of DER. In contrast, the Reactive Framework responds to specific

[194] Xcel, Reply Comments, p. 4-5
[195] Department, Initial Comments, p. 13-14

interconnection applications and addresses constraints only after they arise. Requiring utilities to justify why a proactive project cannot be handled reactively undermines the very premise of proactive planning. It suggests that reactive planning is the default or preferred approach, which contradicts the Commission's broader goals of enabling forward-looking grid investments.

2. *Risks Undermining Planning Flexibility and Innovation*. Utilities need flexibility to identify and pursue proactive upgrades based on system-wide analysis, long-term forecasts, and evolving customer needs. Imposing a rigid justification requirement could discourage utilities from proposing proactive projects altogether, especially in borderline cases where the distinction between proactive and reactive solutions is nuanced. This could stifle innovation and lead to missed opportunities to optimize grid performance and reduce long-term costs.
3. *Adds Unnecessary Administrative Burden*. This requirement would impose a significant administrative burden on utilities, forcing them to prepare detailed justifications for each proactive project—regardless of how clearly it aligns with proactive planning objectives. This would divert time and resources away from actual planning and implementation, slowing down the deployment of needed upgrades.[196]

Staff Analysis: Staff echoes Xcel's comments, and further notes that in its current format, the Proactive Grid Upgrade Framework focuses on behind the meter generation additions, rather than large front of the meter installations. Phase 2 will discuss issues related to front of the meter generation in more depth, including how to balance ratepayer risk for upgrades that are primarily intended to serve DERs that are not associated with load. Therefore, Staff recommends that the Commission take no action on the Department's recommendation.

Decision Option 10 would require Xcel to justify why DER enabling proactive upgrades should go through the proactive process instead of the reactive process.

iii. <u>Equitable Access to Hosting Capacity</u>

Fresh Energy highlighted a concern that solely increasing hosting capacity for under-resourced communities would not necessarily lead to increased DER or electrification adoption. It cited a 2024 study, *Racial and Economic Disparities in Electric Reliability and Service Quality in Xcel Energy's Minnesota Service Area*, that there tend to be higher levels of hosting capacity available in under resourced communities.[197] Fresh Energy explained it would be a reasonable conclusion that the higher levels of hosting capacity could be linked to lower DER adoption. It requested Xcel respond to the following questions with the aim of reducing disparities in its service area:

1. What is the Company's strategy for increasing DER adoption in communities with adequate hosting capacity that may not be candidates for proactive upgrades?

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[196] Xcel, Reply Comments, Attachment 1, p. 34-35

[197] Bhavin Pradhan and Gabriel Chan, Racial and Economic Disparities in Electric Reliability and Service Quality in Xcel Energy's Minnesota Service Area, February 2024, pp. 21-22.

2. How will proactive upgrades benefit customers in communities with poor service quality and high hosting capacity, such as those identified in the Pradhan and Chan study?[198]

ELPC/VS/CEF noted appreciation for Fresh Energy's consideration of equitable access to both hosting capacity and the ability to adopt DER and electrification technologies. ELPC/VS/CEF pointed to their 2023 IDP comments, where they discussed how the excess of hosting capacity in under resourced communicates indicates that it is not the grid that is the barrier to DER access, but rather other financial and social barriers. They supported continued discussion of the questions Fresh Energy raised in Phase 2, but also Xcel's next IDP as this is a broader issue that relates to system planning in general.[199]

Xcel also noted appreciation to Fresh Energy raising the questions, but indicated they involve matters that extend beyond the Framework. The Company provided the following answers to Fresh Energy's questions:

> *DER Adoption in Communities with Adequate Hosting Capacity*. The Company's approach to load and DER interconnection is grounded in system-wide planning principles that prioritize safety, reliability, and cost-effectiveness. In communities with sufficient hosting capacity, there are no immediate technical barriers to DER interconnection. As a result, targeted interventions or proactive upgrades are not necessary.
>
> *Proactive Upgrades in Communities with Poor Service Quality and High Hosting Capacity*. The primary goal of proactive upgrades is to alleviate hosting capacity constraints that hinder load and/or DER interconnection. In communities where hosting capacity is already sufficient, such upgrades are not technically justified—even if those areas experience service quality issues. Service quality concerns are more appropriately addressed through separate, reactive reliability programs specifically designed for that purpose. Blurring the distinction between service quality and hosting capacity could result in inefficient investments and divert resources from the core objective of the Proactive Upgrade Framework: supporting load and DER interconnection in areas where system constraints are expected to limit future hosting capacity.[200]

7. Should the Commission Establish a Phase 2?

All stakeholders recommended establishing Phase 2 of the proceeding, however there were some differences in what the scope and timing of Phase 2 would involve.

A. Topics to include

The Phase 2 proposal included in the April 7, 2025 Notice of Comment included the following proposed topics:

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[198] Fresh Energy, Initial Comments, p. 6-7
[199] ELPC/VS/CEF, Reply Comments, p. 12
[200] Xcel, Reply Comments, Attachment 1, p. 35-36

3. Coordination of the Proactive Distribution Upgrade Process with the Reactive-DER Cost Sharing Process:
   a. Areas of the utility distribution system with existing interconnections queues are eligible for proactive upgrades beyond the reactive upgrades required to interconnect the systems in the existing queue.
   b. Proactive upgrades would be identified as the incremental investment and capacity relative to the reactive upgrade required at the given location to interconnect the systems in the existing queue.
   c. The proactive upgrades at such eligible locations must comply with all other aspects of the proactive upgrade framework
4. Forecasting for FTM generation to identify proactive upgrades, including whether to do a service territory wide analysis of optimal sites for front of the meter generation.
5. Flexible Interconnection.
6. Advanced cost allocation and cost recovery methodologies, including export tariffs.
7. Additional discussion on system wide capacity reservations.
8. A full review of the Proactive Upgrade Framework to incorporate a process for identifying proactive infrastructure upgrades to enable hosting capacity for front of the meter distributed generation.

Stakeholders recommended additional topics during the comment period, including moving some sections from Phase 1 to Phase 2. To simplify the list of potential topics, Staff reorganized potential issues for Phase 2 into the following list, which is captured in **Decision Option 6**:

1. Incorporation of Front of the Meter Generation
2. Coordination and alignment with the Reactive-DER Cost Sharing Program
3. Distributed Generation Engagement Group
4. Flexible Interconnection
5. Cost Allocation and Cost Recovery Principles and Methodologies
6. Capacity Reservation
7. Cost Envelopes
8. Non-Location Specific Measures

i. <u>Incorporation of Front of the Meter Generation</u>

No stakeholders objected to including incorporation of front of the meter generation into the framework as a Phase 2 topic. MNSEIA noted "supporting the interconnection of front-of-the-meter DG is essential to the proactive planning framework and process,"[201] while CCSA explained "proactive grid infrastructure upgrades [for front of the meter generation] are an essential step in enabling more DER deployment and meeting the state's clean energy policy mandates."[202]

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[201] MNSEIA, Initial Comments, p. 9-10

[202] CCSA, Initial Comments, p. 6

CCSA highlighted the risks of relying on a strictly reactive process, as currently exists in Minnesota, for DER enabling upgrades. It explained that reactive upgrades increase uncertainty around the costs and timelines for the upgrades themselves, as well as delaying overall DER adoption. CCSA emphasized that "when stakeholders and regulatory authorities have an active role in the development of planning analyses and transparency into the decision-making process behind grid upgrades, there is more certainty and predictability associated with upgrade costs and construction timelines."[203] In order to advance proactive planning, CCSA recommended that Phase 2 consider the following items in relation to the incorporation of FTM generation into the framework:

- DER Demand Assessment: Xcel should develop a DER demand forecasting tool to identify the most beneficial grid upgrades driven by distributed generation. Stakeholder input must be integrated to ensure the assessment reflects industry needs and market realities.
- DER Infrastructure Upgrade Prioritization: After forecasting DER demand, Xcel should prioritize upgrades based on factors like system benefits, reliability, and the likelihood of DER deployment. Prioritization should also coordinate with investments addressing load growth to maximize value.
- Update of Existing Rules: Regulatory updates are needed to align with proactive planning, including flexibility around payment schedules, cost certainty, use of bonds or letters of credit, and hosting capacity tools. These changes will support smoother financing and equitable cost sharing for FTM DERs. [204]

Xcel recommended that Phase 2 should develop a process for gathering input from DER Developers that can inform the forecast and identify areas that have a higher probability of FTM DER deployment. The Company explained that forecasting the location of FTM DERs is more difficult "due to the large capacity requirement for individual CSGs compared to the hosting capacity of an overall feeder or substation." A forecast inaccuracy for FTM generation therefore has a much larger impact on the need for an upgrade at a particular location than BTM generation.[205]

Decision Option 6.a includes "Incorporation of Front of the Meter Generation" as a topic in Phase 2.

Support: OAG, Department, MNSEIA, ELPC/VS/CEF, Fresh Energy, UCS, Xcel, CCSA

ii. Coordination with the Reactive-DER Cost Share Process

Xcel noted that it did not support including any reactive projects as part of the framework, as they conflict with the definition of a proactive upgrade included in section B.[206]

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[203] CCSA, Initial Comments, p. 7-8
[204] CCAS, Reply Comments, p. 3-4
[205] Xcel, Initial Comments, p. 7
[206] Xcel, Initial Comments, p. 7

ELPC/VS/CEF noted that it had a different understanding of coordination with the reactive upgrade process, stating it understood the topic to "entail discussion of if and how to coordinate this proactive process with the reactive/cost-sharing process developed in a separate work group, rather than any presupposition regarding the inclusion of reactive projects within proactive planning." It also noted that the Department's comments indicate there are still open questions on how the two processes would work together.[207]

Staff Analysis: Staff recommends including this topic because at minimum there are likely to be places where coordination between the Reactive Program and Proactive Program are necessary for administrative reasons. The Reactive Program is still under development, so having the opportunity to discuss both programs together once approved may shed additional clarification on any confusion.

Decision Option 6.b includes "Coordination with the Reactive-DER Cost Share Process" as a topic in Phase 2.

Support: OAG, Department, MNSEIA, ELPC/VS/CEF, Fresh Energy, UCS
Oppose: Xcel

iii. Distributed Generation Engagement Group

As discussed in sections C.10 and C.11, multiple stakeholders supported moving consideration of whether to establish "distributed generation engagement group" or "DGEG" to Phase 2.

CCSA supported adopting C.11 in Phase 1, but explained that further development would be needed during Phase 2:

> In Phase 2 we must determine the cadence, format, and operational procedures for stakeholder engagement in the DER proactive planning process. It is critical to the success of the proactive planning process that Xcel Energy conduct a comprehensive stakeholder engagement process which must include reporting to the Commission on: the stakeholder engagement process, recommendations resulting from the engagement process, and which/how recommendations were incorporated into the Integrated Distribution Plan's associated DER investment proposals (with an explanation and rationale for not incorporating a recommendation).[208]

Therefore, no stakeholder opposed discussion of a DGEG in Phase 2, however the scope of that discussion will depend on whether the Commission adopts C.11.

Decision Option 6.c includes "Distributed Generation Engagement Group" as a topic in Phase 2.

Support: OAG, Department, MNSEIA, ELPC/VS/CEF, Fresh Energy, UCS, CCSA

iv. Flexible Interconnection

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[207] ECLP/VS/CEF, Reply Comments, p. 8
[208] CCSA, Initial Comments, p. 6

The OAG, Department, MNSEIA, ELPC/VS/CEF, Fresh Energy, UCS, and CCSA supported including a discussion of how to include Flexible Interconnection in the Framework in Phase 2. Xcel opposed inclusion.

Stakeholders highlighted multiple benefits to flexible interconnection for both generation and load. Flexible interconnection agreements allow either the utility or the customer to use various methods to control the maximum load or generation impacts of a particular resource on the grid to avoid upgrades.[209] ELPC/VS/CEF pointed out the Commission pushed Xcel to adopt Flexible Interconnection in its 2023 IDP Order. It also explained that allowing proactive upgrades *could* disincentivize Xcel's pursual of FI, "since the goal of flexible interconnection is to maximize use of existing infrastructure." Discussing this tension in Phase 2 would assist in how to balance the use of both proactive upgrades and flexible interconnection to maximize customer benefits.[210] CCSA pointed out that "a flexible interconnection program in Minnesota would allow for distributed generation to interconnect with existing grid infrastructure by utilizing dynamic curtailment as an interim measure until the necessary upgrades are completed that allow for full capacity utilization."[211]

Xcel opposed including flexible interconnection in Phase 2 and in the framework overall, explaining that it is "not an upgrade; rather, it is a way of avoiding some level of upgrades." The Company also pointed out that flexible interconnection is not currently available in Minnesota under the Minnesota Distributed Energy Resources Interconnection Process (MN DIP).[212]

Fresh Energy disagreed with Xcel's assertion, stating that a proactive upgrade framework should consider all potential distribution system investments, "including those that could help offset capacity needs or avoid upgrades…considering flexible interconnection as part of the proactive grid planning process is important for ensuring the resulting framework that considers all opportunities for addressing hosting capacity constraints."[213]

Decision Option 6.d includes "Flexible Interconnection" as a topic in Phase 2.

Support: OAG, Department, MNSEIA, ELPC/VS/CEF, Fresh Energy, UCS, CCSA
Oppose: Xcel

v. Cost allocation and cost recovery principles and methodologies

During Phase 1 of the proceeding, stakeholders introduced concepts like export tariffs and multi-beneficiary pays as alternative methods of cost recovery and cost allocation for interconnecting customers at proactive upgrade locations. Due to the complexity of these novel ways of conducting cost allocation, Staff recommended consideration of these topics in Phase 2. Based on Staff's recommendation, stakeholders held off on offering proposals during Phase 1, but strongly supported discussion of these topics during Phase 2.

[209] ELPC/VS/CEF, Initial Comments, p. 14-16
[210] ELPC/VS/CEF, Initial Comments, p. 14-16
[211] CCSA, Initial Comments, p. 6-10
[212] Xcel, Initial Comments, p. 7-9
[213] Fresh Energy, Reply Comments, p. 2

During comments, two additional subtopics arose that could be included in this section: further development of the cost allocation principles in A.10-A.15, and how to allocate the costs of the Technical Planning Standard. Below Staff briefly summarizes stakeholder positions, noting that many included longer explanations in their comments.

Export Tariffs: ELPC/VS/CEF advocated for including export tariffs, which they explained "extend traditional ratemaking principles for load to exporting customers...and can fairly allocate and recover export-related costs from exporting customers."[214]

Multi-Beneficiary Pays: CCSA advocated for this approach, which it described as "the determination of a capacity-based "common system modification cost" ($/kW) assessed on all distributed generation interconnecting customers, as well as a determination on the proportion of total upgrade costs that will be recovered from distribution customers during a given period of time. Residential and other small distributed generation facilities are typically exempt from the common system modification cost charge and instead pay a lesser fixed fee at the time of interconnection, which serves as their contribution to system upgrades."[215]

Technical Planning Standard: As noted in Section K, MNSEIA supported allocating the costs of the Technical Planning Standard to load customers and not interconnecting generation as it is primarily a reliability benefit to load.[216]

Benefit-Cost Allocation Framework: IREC provided a proposal for "an equipment-centric, benefit-focused cost allocation framework" which it included as an attachment to its initial Comments.[217]

Cost Allocation Principles: as noted in sections A.10-A.15, the Commission may wish to consider whether to adopt specific cost allocation principles as part of the discussion on advanced cost allocation methodologies.

Xcel opposed inclusion of this topic in Phase 2, stating that "there is no reason why cost allocation for proactive distribution upgrades would need to be done differently from other utility investments that are recovered from various customer classes or through participant fees."[218] In response, ELPC/VS/CEF pointed out that Minn. Stat. 216B.2425, subd. 9 explicitly calls out consideration of alternative cost allocation methodologies for DERs. It noted that as Phase 1 focused on existing cost allocation and recovery methodologies due to time constraints, it is appropriate for Phase 2 to have this discussion.[219]

Decision Option 6.e includes "Cost allocation and cost recovery principles and methodologies" as a topic in Phase 2.

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[214] ELPC/VS/CEF, Initial Comments, p. 14-16
[215] CCSA, Initial Comments, p. 6-10
[216] MNSEIA, Initial Comments, p. 9-10
[217] IREC, Initial Comments, p. 4
[218] Xcel, Initial Comments, p. 7-9
[219] ELPC/VS/CEF, Reply Comments, p. 8-12

Support: OAG, Department, MNSEIA, ELPC/VS/CEF, Fresh Energy, UCS, CCSA, CEEM, ACEEE
Oppose: Xcel

vi. Capacity Reservations

All stakeholders supported additional discussions on capacity reservations in Phase 2, despite differing positions on whether the Commission should adopt a proposal from Section L in Phase 1.

Decision Option 6.f includes "Capacity Reservations" as a topic in Phase 2.

Support: OAG, Department, MNSEIA, ELPC/VS/CEF, Fresh Energy, UCS, Xcel, CCSA, CEEM, ACEEE

vii. Cost Envelope

MNSEIA presented a new topic for Phase 2 consideration, which CEEM also supported:

> Proposed Additional Topic - Implementation Of A Cost Envelope To Prevent Cost Overruns. To ensure cost certainty and address variability that may occur between initial construction estimates and as-built costs, Massachusetts has had a ±25%cost envelope in place since 2012. New York is similarly considering a cost envelope. MnSEIA proposes that Minnesota would benefit from determining how to allocate as-built costs when they are over 25% of the utility's initial estimate for the cost of an upgrade. We respectfully request that the Commission direct stakeholders address establishing a ±25% envelope on costs in Phase 2. [220]

Decision Option 6.g includes "Cost Envelopes" as a topic in Phase 2.

Support: MNSEIA, CEEM

viii. Non-Location Specific Measures

As noted in Section H, the Department and OAG advocated for moving consideration of non-location specific measures to Phase 2.

Decision Option 6.g includes "Non-Location Specific Measures" as a topic in Phase 2.

Support: OAG, Department, ELPC/VS/CEF if Section H is not adopted

B. Timing and Structure

The Phase 2 proposal included in the notice for comment suggested that Phase 2 start 30 days after the Commission's Order in the Company's 2025 IDP with a goal of a Commission decision by either Q2 or Q3 of 2027. It also recommended following the structure of Phase 1.

Minnesota Power and the Department supported a Q2 decision, however the Department noted that Commission Staff's workload may ultimately determine the timeline.[221]

Fresh Energy and ACEEE took no position on either a Q2 or Q3 decision, while ELPC/VS/CEF suggested the timing would depend on whether the Commission adopted the full list of

[220] MNSEIA, Initial Comments, p. 9-10
[221] MP, Initial Comments, p. 2; Department, Initial Comments, p. 12-13

proposed Phase 2 topics.[222] If the full list is selected, ELPC/VS/CEF suggested a Q3 decision.[223] ACEEE also encouraged a "peer-learning approach in Phase 2" so the workgroup can learn from experts in other states such as Massachusetts or New York that are working on similar initiatives.[224]

CCSA supported initiating Phase 2 as soon as possible with a goal of a Commission decision in time to incorporate front-of-the-meter generation into Xcel's 2027 Proactive Upgrade Proposal.[225]

As noted above, Xcel recommended narrowing the topics from the Phase 2 proposal to a more focused set of issues. Therefore, the Company supported a shorter timeframe with a goal for a Commission decision before the end of Q4, 2026.[226]

In reply comments, ELPC/VS/CEF noted that Xcel's proposed timeline is overly aggressive, especially given the Commission did not reach a verbal decision on the Company's 2023 IDP until July 2, 2024 with a written order on September 16, 2024. It continued to recommend a Q2, 2027 decision, which it acknowledged would also be an ambitious timeline, but give more room for consideration of the topics proposed for Phase 2.[227]

C. Staff Analysis

Staff concurs with stakeholders that a Phase 2 is necessary to complete the Framework. As noted at the outset of the briefing papers, Staff recommended the creation of a Phase 2 partway through the workgroup process when it became clear that there were enough complex topics to address that would prevent the workgroup from meeting its July 1, 2025 completion goal. Staff continues to believe this was a reasonable approach as it will allow Xcel and the Commission to gain experience with evaluating an initial, smaller Proactive Upgrade Proposal which will inform key portions of Phase 2. However, because of Staff's direction, multiple stakeholders withheld proposals on topics like export tariffs and flexible interconnection to complete Phase 1 on time. Therefore, to give stakeholders a fair opportunity to advocate for their proposals, Staff recommends that Phase 2 include consideration of the topics listed in **Decision Option 6 (all subsections)**. Staff also recommends some structural modifications to the format of Phase 2 in order to conserve both Staff and stakeholder resources and complete the work in a timely manner. Staff proposes that instead of addressing all the proposed topics through one workgroup, the following topics be explored by stakeholder led subgroups:

- The need for and parameters of a separate Distributed Generation Engagement Group stakeholder-engagement process (if moved to Phase 2)
- Flexible Interconnection

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[222] Fresh Energy, Initial Comments, p. 8; ACEEE, Initial Comments, p. 5
[223] ELPC/VS/CEF, Initial Comments, p. 14
[224] ACEEE, Initial Comments, p. 5
[225] CCSA, Initial Comments, p. 6
[226] Xcel, Initial comments, p. 7
[227] ELPC/VS/CEF, Reply Comments, p. 8

- Advanced Cost Allocation and Cost Recovery Methodologies, including export tariffs
- Additional discussions on capacity reservations (if moved to Phase 2)
- Implementation a Cost Envelope
- Non-Location Specific Measures (if moved to Phase 2)

Staff envisions convening an initial one-hour virtual meeting to go over process, set deadlines, and set subgroup rosters. The subgroups would then develop proposals that could be brought back to the full workgroup for evaluation and refinement, similar to how sections of the Phase 1 Framework were developed. This would allow stakeholders that are the most interested in particular topics to focus on those initiatives, but still provide an opportunity for all workgroup members to give feedback before proposals go out for comment. Staff expects the initial process meeting could take place in the early fall of 2025 to give subgroups time to work on their proposals over the course of several months.

For the following topics, Commission Staff would continue to convene the full workgroup:

- Incorporation of Front of the Meter Generation into the Framework
- Coordination with the Reactive-DER Cost Sharing Process

In 2023 Xcel's IDP was not heard until July 2. If the 2025 IDP is heard on a similar schedule, that would leave little time to hold a thorough workgroup process followed by a comment period and still reach a Commission decision with enough time to incorporate it into a 2027 Proactive Upgrade Proposal filing. Staff therefore recommends that some workgroup activities being in the near term, such as education sessions or proposal development by individual stakeholders, prior to convening the more formalized workgroup process. The full workgroup could reconvene in the first half of 2026. Staff defers to Xcel on the time it would need to incorporate any decisions into a 2027 Proposal, and recommends the Commission set a goal for completion in line with that deadline.

8. Technical Issues

Throughout the draft framework there are various minor numbering and reference errors which were noted by commenters. For example, currently the framework skips from Section H to Section J. Various sections will need to be renumbered depending on the decisions made by the Commission if it adopts the framework. Staff recommends the Commission delegate authority to the Executive Secretary to revise the Framework to correct any typographic, numbering, and formatting errors and to ensure consistency with the Commission's order (**Decision Option 7**).

Staff notes that Xcel will need to create tariff pages to effectuate the portions of the framework pertaining to the Cost Share Fees paid by Cost Share Customers. Staff recommends the Commission require the Company to file proposed tariff pages as part of its first Proactive Upgrade Proposal which is anticipated to be filed on November 1, 2025 (**Decision Option 8**). The Commission could then approve, modify, or reject them as part of the Proactive Upgrade decision.

9. Decision Options

Framework adoption

1. Find the proactive grid upgrade workgroup has addressed the topics outlined in the Commission's September 16, 2024 *Order*.
2. Establish a framework for Proactive Distribution Grid Upgrades as outlined below.
3. Adopt the following non-disputed framework sections:
   a. Introduction: A.3
   b. Definitions: Xcel.B.2, B.3; B.4; B.5; B.6; B.9; B.10; B.11, B.12; B.13; B.17
   c. Process: C.1; C.2; C.3; C.4; C.8; C.9
   d. Baseline Information: all subparts
   e. Forecast: Xcel.E.1, E.2; E.3; E.5; E.6
   f. Potential Sites for Proactive Upgrades: all subparts
   g. Proactive Upgrade Proposal Evaluation Criteria: G.1; G.2; G.4; G.7; G.8; G.9; G.10; G.11; G.12; G.13; G.16
   h. Reporting: M.1; M.4; M.5; M.6; M.7; M.8; M.9; M.10; M.11

Note: Staff has not listed each individual section as part of the following decision option, but rather recommends Commissioners include the sections they would like to adopt in the same format as Decision Option 3 above.

4. Adopt the following disputed framework sections:
   a. Introduction:
   b. Definitions
   c. Process:
   d. Forecast:
   e. Proactive Upgrade Proposal Evaluation Criteria:
   f. Proposals for Non-Location Specific Measures:
   g. Cost Recovery:
   h. Cost Allocation:
   i. Capacity Reservation:
   j. Reporting:

Phase 2

If the Commission does not adopt C.11, Section H, or any of the proposals from Section L, it may refer those matters for further development in Phase 2 by selecting DO 5 and the appropriate subparts.

5. Refer the following framework sections for further development in Phase 2:
   a. C.11: Creation of a Distributed Generation Engagement Group
   b. Proposals for Non-Location Specific Measures
   c. Capacity Reservation

6. Delegate authority to the Executive Secretary to convene the Proactive Grid Upgrade Workgroup for Phase 2 of framework development and to set deadlines, schedules, and procedures. The Commission establishes a goal of having a decision on Phase 2 by [*insert date*]. Topics to be developed in Phase 2 shall include, but are not limited to:

    a. Incorporation of Front of the Meter Generation
    b. Coordination and alignment with the Reactive-DER Cost Sharing Program
    c. Distributed Generation Engagement Group
    d. Flexible Interconnection
    e. Cost Allocation and Cost Recovery Principles and Methodologies
    f. Capacity Reservation
    g. Cost Envelopes
    h. Non-Location Specific Measures

Technical and Other Issues

7. Delegate authority to the Executive Secretary to revise the Framework to correct any typographic, numbering, and formatting errors and to ensure consistency with the Commission's order.

8. Require Xcel Energy to file tariff pages that implement the relevant portions of the Proactive Distribution Grid Upgrade Framework with its first Proactive Upgrade Proposal.

9. Amend Xcel Energy's IDP Filing Requirements to include the following new provision:

    > Forecast results for generation and peak loads at the feeder/substation level for all locations that have a potential proactive upgrade need, as well as the standard reactive upgrade capacity upgrade.

10. As part of its proactive upgrade proposal, require Xcel Energy to justify why DER enabling proactive upgrades should go through the proactive process instead of the reactive process.