Xcel Energy®

414 Nicollet Mall
Minneapolis, MN 55401

June 2, 2025

—Via Electronic Filing—

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

RE: REPLY COMMENTS
PROACTIVE DISTRIBUTION UPGRADES AND COST ALLOCATION
DOCKET NO. E002/CI-24-318

Dear Mr. Seuffert:

Northern States Power Company, doing business as Xcel Energy, submits the enclosed Reply Comments in response to the April 7, 2025 Notice of Comment Period in the above-referenced docket.

We have electronically filed this document with the Minnesota Public Utilities Commission, and copies have been served on the parties on the attached service lists. Please contact Taige Tople at taige.d.tople@xcelenergy.com or me at brian.t.monson@xcelenergy.com if you have any questions regarding this filing.

Sincerely,

/s/

BRIAN MONSON
MANAGER, DISTRIBUTION REGULATORY STRATEGY

Enclosures
cc: Service List

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Katie J. Sieben	Chair
Hwikwon Ham	Commissioner
Audrey C. Partridge	Commissioner
Joseph K. Sullivan	Commissioner
John A. Tuma	Commissioner

IN THE MATTER OF A COMMISSION INQUIRY INTO A FRAMEWORK FOR PROACTIVE DISTRIBUTION GRID UPGRADES AND COST ALLOCATION FOR XCEL ENERGY

DOCKET NO. E002/CI-24-318

REPLY COMMENTS

INTRODUCTION

Northern States Power Company, doing business as Xcel Energy, submits these Reply Comments to the Minnesota Public Utilities Commission in response to comments submitted by several parties on May 8, 2025, consistent with the Commission's April 7, 2025 Notice of Comment Period. The Notice follows the conclusion of a Commission-led stakeholder workgroup process stemming from the Commission's September 16, 2024 Order on the Company's 2023 Integrated Distribution Plan.[1]

At the outset, we note there is broad agreement across stakeholders that the Commission should implement a Framework for proactive distribution grid upgrades, recognizing its potential to streamline investment review, enhance system readiness, and deliver long-term customer value.

We highlight in this Reply the key areas we believe are essential to a constructive Framework, including:

- The need for an advance determination of prudence for qualifying projects
- Use of standard class cost allocations
- A five-year cost-share window
- The importance of the optional nature of the framework

Attachment 1 to this Reply provides comprehensive responses to each proposed

[1] *In the Matter of Xcel Energy's 2023 Integrated Distribution Plan*, Docket No. E002/M-23-452, ORDER (September 16, 2024).

Framework provision, highlighting areas of agreement and addressing remaining differences. We reaffirm our initial recommendations and respond to stakeholder input with the goal of supporting a Framework that is both forward-looking and practicable to implement.

Attachment 2 to this Reply provides a clean version of the phase 1 Framework provisions we support. These provisions are largely consistent with the Framework we outlined in our initial comments, with our proposed revisions to Requirements shown in blue redline format. We have also highlighted the two Requirements where we are proposing minor additional revisions to in these Reply Comments. No changes have been made to the Phase 2 Framework provisions we supported in our initial comments.

I. ADVANCE DETERMINATION OF PRUDENCE FOR APPROVED PROJECTS

An advanced determination of prudence for approved projects is necessary to ensure a reasonable level of certainty for utilities to confidently pursue major infrastructure investments. This upfront regulatory certainty is balanced with utility accountability to deliver the project as-approved and bear the burden of demonstrating any costs above the approved final estimate were prudently incurred.

There is a subtle, but important, difference in the proposed Framework provisions J.13–J.16. J.13 offers a *rebuttable presumption of prudence*, while J.14–J.16 go further by providing an *advance determination of prudence*.

We oppose J.13 and support J.14–J.16. The rebuttable presumption in J.13 lacks the certainty needed for utilities to confidently pursue major infrastructure investments. Even with Commission approval, costs could still be challenged during recovery with the benefit of hindsight, undermining proactive planning and delaying upgrades.

In contrast, J.14–J.16 offer a stronger, more effective approach:

1. *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.

2. *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.

3. *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.

4. *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.

II. USE OF STANDARD CLASS COST ALLOCATIONS

Some parties advocate for specialized cost allocation for projects approved under the Proactive Grid Upgrades Framework. We believe the Commission should continue to rely on tried-and-true, industry standard, cost allocation principles and mechanisms 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.

We encourage the Commission to reject K.7–K.12's custom cost allocations in favor of consistent, industry standard, established methods used to recover all other infrastructure investments whether it be in rate cases or riders.

III. A FIVE-YEAR COST SHARE WINDOW IS APPROPRIATE

A Cost Share Window, in the context of this proceeding, refers to a defined period during which the costs of approved grid upgrades are shared among connecting load and DER customers, rather than being fully borne by the first project that triggers the upgrade.

The Framework presents two alternatives for structuring the cost share window:

- A five-year window, as proposed in J.7–J.9,
- A 15-year window, as proposed in J.5–J.6, and
- A life-of-the-asset window, as proposed in the OAG's and Department's J.6.

The five-year window provided by J.7–J.9 is a more balanced and practicable approach. The first five years represents the most likely timeframe in which anticipated customer connections that drove the need for the project will occur – aligning cost-sharing opportunities with actual demand. Closing the window five years after the need date identified in the approved project provides a reasonable timeframe for participation while enabling timely cost recovery for the Company – unlike the extended delays associated with J.5 and J.6. A 5-year structure also 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.

In contrast, we oppose keeping the cost share window open for the life of the asset—up to 40 years in some cases—as proposed by the OAG and Department's J.6. This is unreasonable, impracticable, and administratively burdensome. Similarly, we oppose the 15-year window proposed in J.5–J.6 as it also delays cost recovery beyond what is reasonable for capital investments, creating financial uncertainty and discouraging timely infrastructure development.

For these reasons, we urge the Commission to adopt the 5-year window in J.7–J.9 and reject the alternatives in J.5–J.6.

IV. Proactive Upgrade Proposals are Optional

We believe that proactive upgrades should remain optional rather than mandatory. Utilities are best positioned to identify when and where proactive investments are warranted, based on system-specific conditions, resource availability, and planning priorities. Mandating evaluations and upgrades in the absence of proposed projects risks diverting attention and resources away from higher-impact opportunities. A flexible, utility-driven approach allows for more targeted, efficient planning and ensures that proactive upgrades are pursued when they are most likely to deliver meaningful system benefits.

The Department recommends all utilities be required to follow the Proactive Distribution Grid Upgrades Framework and evaluate their systems for upgrades—even if no projects are proposed. This recommendation also includes a new IDP filing requirement to disclose feeder- and substation-level forecasts for locations with potential needs.

We respectfully oppose both recommendations for several reasons:

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 non-actionable locations would divert resources from higher-value planning, with little added value for stakeholders or regulators.

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.

While we support transparent, data-driven planning, the Department's proposal is unnecessary, potentially confusing, and administratively burdensome. The existing IDP process and draft framework already provide a strong foundation. We urge the Commission to preserve flexibility and focus on actionable, value-driven planning.

CONCLUSION

The Company appreciates the opportunity to provide these Reply Comments on the proposed Proactive Distribution Grid Upgrades Framework. We support the Commission's goal of creating a forward-looking, transparent, and equitable planning process. However, as outlined in our comments and this reply, the Framework must balance innovation and proactive planning with regulatory clarity, administrative practicability, and cost-effectiveness.

We urge the Commission to adopt a framework that:

- Preserves utility flexibility to prioritize based on system needs and data.
- Avoids duplicative or overly prescriptive requirements.
- Aligns with established cost allocation and recovery principles.
- Encourages stakeholder input while upholding the utility's service obligations.

We remain committed to working with the Commission and stakeholders to develop a durable framework that supports Minnesota's clean energy goals, while ensuring reliable, affordable service for all customers.

Dated: June 2, 2025

Northern States Power Company

This attachment discusses every proposed Framework requirement. We note the many areas of agreement among stakeholders but focus on areas where disagreements remain. Section I discusses Attachment A on Phase I of the Framework, Section II discusses Attachment B on Phase II of the Framework, and Section III discusses additional considerations raised by the Department of Commerce and Fresh Energy. The green boxes indicate our preferred Framework options.

We largely maintain the recommendations provided in our initial comments and respond to parties' comments for each section of the framework. Our goal is to support a framework that is both forward-looking and practical to implement.

I. ATTACHMENT A

A. Section A – Framework Goals

1. A.1-A.3

We do not oppose A.1 and no stakeholders oppose A.2-A.3.

2. *A.4 and A.5*

A.4 and A.5 are alternatives:

> A.4 Protect ratepayers by establishing a rigorous review of proposed proactive investments to ensure they do not cause undue costs or result in inequitable distribution of costs or benefits.

> A.5 Protect ratepayers by establishing a ~~rigorous~~ review of proposed proactive investments to ~~ensure they do not cause undue risk costs or~~ minimize the risk of stranded assets or projects that result in inequitable distribution of costs or benefits.

We support A.5 over A.4 for several reasons. First, as outlined in our initial comments, we believe A.5 offers greater clarity regarding the specific risks and costs this framework is designed to minimize. Second, the term "rigorous" in reference to the review of proposed proactive investments is vague. Without a clear definition, we are concerned that such a review could become overly and unnecessarily burdensome for the Company.

We understand that the Office of the Attorney General (OAG) is concerned that stranded assets are not the only potential source of undue costs, noting that underutilized assets and unreasonably expensive projects could also contribute to undue costs. However, we believe A.5 addresses these concerns through its language—specifically, the reference to "projects that result in inequitable distribution of costs or benefits."

3. A.6 and A.7

A.6 and A.7 are alternatives:

> A.6 Maximize the benefits to the distribution system while minimizing the costs.

> A.7 To the extent reasonably possible, maximize the benefits to the distribution system while minimizing the costs.

We support A.7 over A.6 because it offers a more balanced and realistic approach. It acknowledges the importance of maximizing net benefits while recognizing practical limitations. We agree with the principle in A.7 that benefits should outweigh costs whenever reasonably possible.

4. A.8 and A.9

A.8 and A.9 are alternatives:

> A.8 Limit cost impacts to ratepayers from forecast inaccuracies.

> A.9 Limit cost impacts from unreasonable forecast inaccuracies.

We support A.9 over A.8 because it more accurately reflects the nature of forecasting. All forecasts involve some level of inaccuracy, as they attempt to predict future conditions. A.9 appropriately focuses on limiting the risks associated with forecasts that are excessively or unreasonably inaccurate, rather than trying to eliminate all inaccuracies.

5. A.10

All stakeholders support A.10.

6. A.11 and A.12

A.11 and A.12 are alternatives:

> A.11 Costs should be allocated to the customers or classes causing the costs, when appropriate.

> A.12 Costs should be allocated to the customers or classes causing the costs, ~~when appropriate~~ whenever possible.

We support A.11 over A.12. The phrase "when appropriate" provides sufficient flexibility and clarity, without introducing the redundancy of "whenever possible." We believe that rate cases are the appropriate venue for determining cost allocation methods and assessing what is appropriate for each customer class.

While the OAG has expressed concern about protecting ratepayers from subsidizing projects that do not benefit them, we believe A.11 already addresses this concern. It ensures that cost responsibility is fairly assigned, consistent with established regulatory processes.

7. A.13 and A.14

A.13 and A.14 are alternatives, and we oppose both:

> A.13 If cost-causation cannot be determined, costs should be allocated according to the distribution of benefits.

> A.14 ~~If cost-causation cannot be determined, costs should be allocated according to~~ Cost allocation may take into account the distribution of benefits.

We oppose A.13 because it implies the use of custom allocation formulas to assign project costs based on perceived benefits. We strongly believe that only cost allocators approved through established rate cases should be used. Introducing custom formulas would undermine the consistency and transparency of the cost allocation process.

While the OAG argues that customers or classes benefiting from upgrades should bear the associated costs when a clear cost-causer cannot be identified, this approach would require custom allocations. Moreover, not all customers within a class benefit equally from a given upgrade. For example, large industrial customers in downtown Minneapolis may not benefit from an upgrade intended for similar customers in downtown St. Paul.

We also oppose A.14 because it introduces ambiguity. It is unclear whether this language would require adherence to the rate case methodology or allow deviations from it. This uncertainty could complicate the cost allocation process and lead to inconsistent outcomes.

8. A.15

A.15 is a standalone requirement:

> A.15 Costs should be allocated according to the distribution of benefits.

We oppose A.15 because it conflates cost allocation with cost causation. In established regulatory practice, costs are typically recovered from cost causers on a pro rata basis, which may reflect the distribution of benefits but is not determined by it alone. Any remaining costs not directly assigned to cost causers are recovered through base rates and should be allocated in the same manner as other system-wide costs. A.15 risks introducing inconsistency by suggesting that benefit distribution alone should drive cost allocation, regardless of causation or established rate case methodologies.

B. Section B – Definitions

1. B.1-B.6

Stakeholders are aligned on B.1–B.6 overall. We oppose B.1, which no other party has taken a position on. We support B.2 with the minor proposed changes we noted in our initial comments.[1] All stakeholders support B.3–B.6.

2. B.7 and B.8

B.7 and B.8 are alternatives:

> B.7 Distributed Generation (DG): a 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 Interconnection Procedures.

> 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~~,~~ and operates in parallel with the utility~~, and is eligible for interconnection under the Minnesota Distributed Interconnection Procedures~~.

We support B.8 because it provides a more broadly applicable and general definition of Distributed Generation.

The Department has expressed concern that B.7 omits the phrase "and is eligible for interconnection under the Minnesota Distributed Interconnection Procedures." We are open to including this language in B.8 to address that concern. However, if the intent is to reference the Minnesota Distributed Energy Resources Interconnection Process (MNDIP), we recommend updating the phrase to: "and is eligible for

[1] Xcel Energy B.2 (proposed in initial comments): Cost-Share Customer: a customer who applies to interconnect either load or generation at a location served by a Proactive Distribution Upgrade with an open cost-share window and is responsible for paying a Cost-Share Fee, unless otherwise specified in approved tariffs.

interconnection under the Minnesota Distributed Energy Resources Interconnection Process."[2]

3. B.9-B.13

All stakeholders support B.9-B.13.

4. B.14 and B. 15

B.14 and B.15 are alternatives:

> B.14 Proactive Upgrade Proposal: one or more Proactive Distribution Upgrades submitted for Commission approval under the Proactive Distribution Upgrade Framework.

> B.15 Proactive Upgrade Proposal: one or more Proactive Distribution Upgrades submitted for Commission approval under the Proactive Distribution Upgrade Framework. <u>In the context of this framework, the Proactive Distribution Upgrades submitted in the Proactive Upgrade Proposal would not be considered prudent under existing distribution planning practices due to the proactive nature of the projects.</u>

We support B.15 because it adds important specificity that distinguishes traditional distribution investments from those made under the Proactive Distribution Upgrade Framework. This distinction is essential, as the proactive nature of these projects is the very reason for developing a separate proposal process. We maintain our initial position in support of this language.

The OAG has expressed concern that the additional redline language in B.15 implies that proactive distribution planning is inherently imprudent. We do not interpret it that way. Rather, we believe B.15 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 OAG also suggested that if this additional redline language is retained, it may be more appropriate in B.16 rather than B.14. We do not oppose relocating the language to B.16 if that improves clarity and alignment with the framework's structure.

---

[2] The Company notes, however, that there are DG facilities that exceed the proposed 10 MW cap in the definition of Distributed Generation as applied to the Proactive Upgrade program. See, for example, MPUC Docket No. 16-445 (addressing an interconnection agreement for a 22.8 MW DG CHP system); Docket No. 17-773 (addressing an interconnection agreement for a 49.9 MW DG CHP system); and, Docket No. 18-714, filing of October 31, 2023 (addressing an interconnection agreement for a 45 MW DG Solar system).

5. B.16

B.16 defines a proactive distribution upgrade, and the Alliance for Transportation Electrification (ATE) has proposed an alternative definition:

> B.16 Proactive Distribution Upgrade: a distribution upgrade made solely based on a forecasted need outside a utility's traditional planning cycle.

> ATE B.16 Proactive Distribution Upgrade: distribution system proactive investments [are] those that are deployed 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.

We, along with all other commenting parties except ATE, support the original definition in B.16. We oppose ATE's proposed changes. ATE's version lacks clarity and could broaden the framework to include projects that utilities already undertake today. While not every current project is tied to a specific customer or immediate need, they are still planned within our traditional 5-year cycle. Including such projects under this framework would be inappropriate and inconsistent with its intended purpose.

6. B. 17

All stakeholders support B.17

C. Section C - Process

1. C.1-C.4

All stakeholders support C.1-C.4.

2. C.5-C.7

C.5 through C.7 are alternatives and one may be adopted with any other requirements. Only C.6 is in contention. C.6 reads:

> 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 impact overall project cost.

We oppose C.6 as currently written and propose a revision for clarity and to address unreasonable risk that C.6 introduces for the Company.

If previously approved projects are subject to reapproval for vague or unspecified reasons, this introduces an unacceptable level of uncertainty; under such conditions, the Company is unlikely to initiate projects within this framework.

Our 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. This scenario presents a significant risk to the Company.

However, we understand and support the need for reapproval in cases where a forecast change occurs before any project costs are incurred or construction has started. To address the concerns of all parties, we propose the following revision – with our changes reflected in blue redline format:

> Xcel Energy 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.

3. C.8-C.10

Stakeholders are largely aligned on C.8-C.10. All stakeholders support C.8 and C.10. We proposed minor modifications to C.9 in our initial comments for clarity.

4. C.11

C.11 is a standalone requirement:

> C.11 Coordination with distributed generation developers:
>
> > C.11.a [Utility] shall establish a distributed generation stakeholder engagement group (DGEG) to coordinate stakeholder engagement with the Utility on proactive long-term system planning. The DGEG shall be co-facilitated by the [utility] and a DG stakeholder representative and shall consist of one representative from the Department of Commerce, one representative from the Office of the Attorney General, and six DG stakeholder representatives (one of which must be a developer that conducts 60% or more of its business in residential DG, one of which must be a developer that conducts 60% or more of its business in C&I DG, one of which must be a developer that conducts 50% or more of its business in energy storage). DG industry trade associations shall work together to conduct industry elections for the six DG stakeholder representatives for each IDP iteration.
> >
> > C.11.b [Utility] must engage with the DGEG to collect input for the forecast prior to

> it being finalized and used to identify locations of proposed upgrades. Forecast input should focus on identifying geographic areas that have a higher likelihood to adopt DG and electrification.
>
> C.11.c [Utility] must engage with the DGEG to collect input for prioritizing infrastructure upgrades at the planning stage of the analysis prior to Proactive Upgrade Proposal to the Commission.
>
> C.11.d DGEG input must be collected in a manner that can be incorporated into the [utility's] forecasting tool and for use in prioritizing infrastructure upgrades in a Proactive Upgrade Proposal.
>
> C.11.e The Utility must include DGEG recommendations in its Proactive Upgrade Proposal filing with the Commission and explain how it did or did not incorporate recommendations.
>
> C.11.f [Utility] must also collect DGEG input to inform prioritization of site proposals. This outreach shall be conducted during the first half of odd-numbered years, in the lead up to finalizing site proposals for the November 1 filing in odd-numbered years.

MnSEIA supports adopting C.11 in Phase 1 of the framework while the Company, Fresh Energy, the Department, and OAG oppose C.11 for Phase 1 and believe that more discussion of these topics is needed during Phase 2. The topics identified in C.11.a–f warrant further discussion during Phase 2. We strongly oppose C.11 for several 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.

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.

D. Section D – Baseline Information

All stakeholders are in alignment on Section D, supporting D.1-D.5.

E. Section E - Forecast

All stakeholders support E.2-E.3 and E.5-E.6. The Company presented slight modifications to E.1 and E.4 in initial comments.

F. Section F – Potential Sites for Proactive Upgrades

All stakeholders support F.2-F.8. The only requirement in contention is F.1, which MNSEIA has also proposed a modified version of:

> F.1 The criteria used to identify potential sites for proactive distribution upgrades, including a discussion of feedback received from stakeholders under Section C.8 - Stakeholder Outreach.
>
> MNSEIA F.1 The criteria used to identify potential sites for proactive distribution upgrades, including a discussion of feedback received from stakeholders under Section ~~C.8~~C.11 - Stakeholder Outreach.

The Company, along with the Department, OAG, ELPC/VS/CEF, and Fresh Energy support F.1. However, we believe the reference to C.8 is a mistake and should read C.10. C.8 is not relevant to F.1 and requires utilities to pursue cost recovery through a separate proceeding for any incurred proactive upgrade proposal expenditures. C.10 is relevant to F.1 and discusses utilities engaging with interest stakeholders prior to the forecast being finalized and used to identify locations of proposed upgrades. All the parties that support F.1 also support C.10. To address this, we propose the following revision:

[3] Minn. Stat. § 216B.01.

> Xcel Energy F.1 The criteria used to identify potential sites for proactive distribution upgrades, including a discussion of feedback received from stakeholders under Section ~~C.8~~C.10 - Stakeholder Outreach.

We oppose MNSEIA's modified F.1, which would require utilities to coordinate directly with DG developers. As discussed above in Section I.C, the topics identified in C.11.a–f warrant further discussion during Phase 2.

G. Section G – Proactive Upgrade Proposal Evaluation Criteria

1. G.1-G.2

All stakeholders support G.1-G.2.

2. G.3

G.3 is a standalone requirement and MNSEIA has proposed a modification:

> G.3 The cost per unit of capacity gained.

> 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.

We, along with all parties other than MNSEIA, support the original version of G.3 because it provides a clear, objective, and quantifiable metric that can be consistently applied across projects.

We oppose MNSEIA's proposed modification to G.3. While G.3 is intended to serve as one of the criteria for evaluating proposed upgrades, it is unclear what additional value MNSEIA's expanded language would bring to the evaluation process. Furthermore, it is not evident why the utility should be responsible for determining or providing this information. The utility is not in a position to assess what cost levels are or are not viable for interconnecting customers.

3. G.4-G.6

G.4-G.6 are standalone requirements:

> G.4 The lead time for the upgrade.

> G.5 The risk of deferring the upgrade, or using the existing distribution planning process, including quantifying the potential energization delays (in years) and number of customers impacted by delays.
>
> G.6 Discussion of whether [utility] performed a non-wires alternative (NWA) for the project, and if so, the results of the analysis. If [utility] did not perform an NWA, provide a discussion of alternative measures 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.

We support G.4 and oppose G.5 and G.6

While the Department and OAG support G.5, they have not provided a rationale. We continue to support G.4 over G.5 because we believe G.5 is redundant. The primary risk of deferring a proactive upgrade is the potential need for a reactive upgrade once a system need arises. In such cases, the energization delay for interconnecting customers would be equivalent to the upgrade's lead time—an issue already addressed under G.4.

Similarly, the Department and OAG support G.6 without explanation. We maintain our opposition to G.6 for the following reasons:

1. *Redundancy with Existing IDP Requirements.* Projects that meet the Integrated Distribution Planning (IDP) criteria for NWA analysis already have those results included in the Company's concurrent IDP filing. G.6 would unnecessarily duplicate this effort.

2. *Unjustified Resource Burden.* Requiring similar analyses for projects that do not meet NWA criteria would place an undue burden on Company resources and could delay the development of Proactive Upgrade proposals.

3. *Overreach Beyond Intent of Alternative Consideration.* Fresh Energy supports G.6, arguing that utilities should demonstrate they have considered alternatives and reference existing NWA analyses. While we agree with the principle of evaluating alternatives, G.6 goes beyond this by requiring a discussion of alternatives even when the project does not qualify for NWA analysis. This exceeds what is reasonable or necessary for effective planning.

4. *Misalignment with Proposal Review Objectives.* The review of a Proactive Upgrade Proposal should focus on the merits of the submitted project—not on evaluating all potential alternatives that were not proposed. The utility is responsible for selecting and submitting the option that best balances system

performance, cost, long-term planning needs, and other relevant factors.

4. G.7-G.13

All stakeholders support G.7-G.13.

5. G.14 and G.15

G.14 and G.15 are alternatives:

G.14 Which of the following desired outcomes of the proactive planning process would be facilitated by the proposed upgrade?

G.14.a Anticipate Adoption Speed: Increased adoption speed of DERs and electrification by removing grid barriers.

G.14.b Coordinate Impacts: Avoided risk of construction/procurement bottlenecks.

G.14.c Efficiency: Degree of lifecycle cost reduction or overall spending efficiency achieved.

G.15 Which desired outcomes of the proactive planning process would be facilitated by the proposed upgrade.

We believe G.15 is the superior approach, and we oppose G.14. The specific outcomes listed in G.14 are already addressed elsewhere in the Framework, making G.14 redundant. For example, G.14a, which focuses on accelerating the adoption of DER, overlaps with the objectives outlined in A.2 and A.3. Likewise, G.14b, which addresses avoiding construction and procurement bottlenecks, is already contemplated throughout Section C. Finally, G.14c, which emphasizes lifecycle cost efficiency, is covered by A.5, A.7, and A.9 through A.11. G.15 offers a more streamlined and flexible way to evaluate how a proposed upgrade supports the goals of proactive planning, without duplicating existing content.

6. G.16

All stakeholders support G.16.

H. Section H – Proposal for Non-Location Specific Proactive Measures

All stakeholders support H.1 and only H.2 is in contention. H.2 is a standalone requirement:

> H.2 In proposing such measures or initiatives, the utility shall consider whether there are basic, low-cost upgrades that can be done as a part of standard maintenance.

We oppose H.2 because it does not clearly establish a new or distinct obligation. The coordination of standard maintenance activities with project work is already integrated into the Company's existing planning and operational processes. If basic, low-cost upgrades can be completed as part of routine maintenance, they would not require inclusion in the Proactive Distribution Grid Upgrade process. As such, H.2 appears redundant and does not add meaningful value or clarity to the existing framework.

I. Section I (Does not exist in Framework)

J. Section J – Cost Recovery

1. J.0

OAG has proposed a new requirement that we oppose:

> OAG J.0 The primary mode of cost recovery for proactive distribution upgrades is through a utility's base rates.

While base rates will likely be the primary recovery method, we believe the Framework should remain flexible and not preclude other cost recovery mechanisms that may be appropriate in the future.

2. J.1-J.4

Stakeholders are largely aligned on J.1-J.4. We do not oppose J.1 and J.2. All other stakeholders support J.2, and all but the Department support J.1. We support J.3 and J.4 with minor proposed modifications for clarity.[4]

3. J.5-J.9

J.5-J.6 and J.7-J.9 are alternative packages:

---

[4] Our modifications are in blue redline format. Xcel Energy J.3 (proposed in initial comments): Expenditures for approved proactive upgrades shall be tracked as regulatory assets and/or receive deferred accounting treatment to ensure that the costs of the upgrades are transparently accounted for and ~~can~~ are eligible to be recovered.
Xcel Energy J.4 (proposed in initial comments): All cost-share fees collected from Cost-Share Customers shall be returned to ratepayers as an offset to the revenue requirements of proactive upgrade capital investments.

J.5 Each approved proactive distribution upgrade shall have a cost-share window of at least 15 years that starts upon the upgrade being placed in service. During the cost-share window, cost-share fees from Cost-Share Customers act as an offset to the utility's capital investment in the proactive distribution upgrade. No costs are socialized to ratepayers during this time.

J.6 Where socialization of an upgrade's cost (i.e., rate-base treatment) begins with the utility's next rate case following the upgrade's in-service date, the cost-share window for that upgrade shall remain open until the upgrade is fully depreciated to help mitigate risks to ratepayers.

OAG J.6 ~~Where socialization of an upgrade's cost (i.e., rate-base treatment) begins with the utility's next rate case following the upgrade's in-service date, t~~The cost-share window for ~~that~~ an upgrade shall remain open until the upgrade is fully depreciated to help mitigate risks to ratepayers.

DOC J.6 ~~Where socialization of an upgrade's cost (i.e., rate-base treatment) begins with the utility's next rate case following the upgrade's in-service date, t~~The cost-share window for that upgrade shall remain open until the upgrade is fully depreciated to help mitigate risks to ratepayers.

J.7 Each approved Proactive Distribution Upgrade shall have a Cost Share Window that starts the year that the Proactive Distribution Upgrade project is placed in-service. The duration of the Cost Share Window shall be until 5 years after the anticipated need date for the Proactive Distribution Upgrade at the time of approval. During the Cost Share Window, Cost-Share Fees from Cost-Share Customers act as an offset to the revenue requirements of all Proactive Distribution Upgrades.

J.8 At the end of the Cost Share Window, any remaining costs that have not been offset by Cost Share Fees are placed into ratebase and no longer subject to this cost sharing program.

Xcel Energy J.8 Upon completion of the project, the total costs of the upgrade are placed into rate base. ~~At the end of the Cost Share Window, any remaining costs that have not been offset by Cost Share Fees are placed into ratebase and no longer subject to this cost sharing program.~~

J.9 Interconnecting customers that apply to interconnect on or before the cost share window end date are Cost-Share Customers. For generation interconnections, the date of applying to interconnect shall be the Deemed Complete date.

We oppose J.5 and all proposed versions of J.6 for the following reasons:

- *Excessive Duration.* A 15-year cost-share window is excessively long. Utility costs should be recovered within a reasonable timeframe.

- *Mismatch with Forecasted Need.* Starting the cost-share window at the in-service date does not account for when the forecasted need for the upgrade actually materializes. For example, an upgrade may be justified by a forecast showing increased demand beginning ten years later. In such cases, the cost-share window may close before the anticipated adoption occurs.

- *Administrative Burden.* Keeping the cost-share window open for the full life of the asset, as proposed in J.6, imposes an unreasonable administrative burden on the utility. This burden will grow with each additional proactive upgrade approved under this Framework.

We support J.7–J.9 because they offer a more practical and balanced approach to cost-sharing:

- *Better Timing.* Tying the cost-share window to the anticipated need date ensures it remains open when customer adoption is most likely, avoiding premature closure.

- *Reasonable Duration.* A defined window—ending five years after the need date—supports timely cost recovery without the long delays proposed in J.5–J.6.

- *Administrative Simplicity.* This approach avoids the long-term tracking burdens of indefinite cost-share windows, making it easier to manage as more projects are approved.

- *Fair Customer Treatment.* J.9 clearly defines eligibility, ensuring transparency and consistency in applying cost-share fees.

4. J.10-J.12

J.10 establishes a cost cap. J.11 and J.12 may be adopted with J. 10. They read as follows:

> J.10 Total proactive upgrade costs recoverable from ratepayers shall be capped in some manner, such as a percentage of the total capacity-related five-year budget in the IDP, or a specified dollar cap on proactive upgrades. The cost cap shall be determined as part of the Commission's first Proactive Upgrade Proposal decision.
>
> J.11 Capital expenditures that have been offset by cost-share fees do not count against the cap.
>
> J.12 After a project's cost-share window has closed, the project shall be considered system assets and associated costs shall no longer count against the cap.

We oppose provisions J.10 through J.12 because we believe a cost cap on proactive upgrades is unnecessary and could be counterproductive. Utilities already engage in comprehensive capital planning processes that are subject to regulatory oversight and public input. Within our budgeting process, proactive upgrades are evaluated alongside other infrastructure investments and prioritized based on system needs, reliability goals, available capital, and long-term planning considerations. Imposing an arbitrary cap could constrain the utility's ability to respond flexibly to emerging needs, technological advancements, or evolving policy objectives—particularly in areas with rapid growth or grid modernization requirements.

Moreover, a rigid cost cap may inadvertently discourage proactive investments that could ultimately reduce long-term costs, improve system resilience, or support clean energy integration. Instead of a cap, we support a transparent planning and review process that allows for case-by-case evaluation of proposed upgrades.

However, if the Commission decides to implement a cost cap, we strongly support the inclusion of J.11 and J.12. These provisions are essential to ensure the cap is applied fairly and does not penalize utilities for leveraging cost-sharing mechanisms or for transitioning completed projects into system assets. J.11 ensures that cost-share contributions are properly accounted for, preventing double-counting against the cap. J.12 provides clarity on the treatment of project costs after the cost-share window closes, aligning with standard accounting practices and supporting long-term asset management.

5. J.13-J.16

J.13 is an alternative to J.14-J.16. J.13-J.16 state:

> J.13 The Commission's Proactive Upgrade Proposal decision creates a rebuttable presumption, in a cost-recovery proceeding, that upgrades completed consistent with the decision are prudent.
>
> J.14 The Commission's Proactive Upgrade Proposal decision constitutes an advance determination of prudence for the projects approved in the Proactive Upgrade Proposal.
>
> J.15 If a project receives advanced determination of prudence, this means that at the time cost recovery is being considered, costs that align with the original proposal cannot be deemed imprudent.
>
> J.16 If the Commission does not provide an advanced determination of prudence for the project, then for that reason alone, the utility may choose not to proceed with the project.

We oppose J.13 and support the approach outlined in J.14–J.16.

While the Department and OAG support J.13, citing its similarity to the Integrated Resource Plan (IRP) approval process. We disagree. We believe the advanced determination of prudence concept provided in J.14–J.16 is essential for many reasons:

1. *Maintains Accountability*. J.14–J.16 maintain appropriate regulatory oversight and do not constitute a predetermination of cost recovery. While this Framework is not a substitute for a cost recovery proceeding, utilities proposing projects under this Framework are still held to the same rigorous "just and reasonable" standard.[5] Only costs consistent with the approved project scope and final cost estimate may be included in future cost recovery proceedings. If a utility materially deviates from the approved project, the utility bears the burden to justify the prudence of those costs. Because projects proposed under this Framework may not meet our typical prudence standards, we require an advance determination of prudence before proceeding with these projects. Without an advanced determination of prudence, utilities may not propose proactive upgrades due to unreasonable cost recovery risk. This approach strikes a fair balance between regulatory certainty and utility accountability.

2. *Advanced Determination Provides Predictability*. An advance determination of prudence ensures that utilities can proceed with confidence, knowing that costs aligned with the approved proposal will be recoverable. This certainty is reasonable and essential for long-term planning, financial modeling, and securing internal and external support for capital-intensive projects.

3. *Reduces Regulatory Burden and Redundancy*. Revisiting prudence at the time of cost recovery for already-approved projects introduces unnecessary regulatory complexity and uncertainty. J.14–J.16 streamline the process by resolving prudence questions upfront, eliminating duplicative review, and focusing later cost recovery proceedings on exceptions.

4. *Aligns with Broader Policy Goals*. Advance prudence determinations align with the Commission's goals of proactive grid modernization, DER integration, and long-term system planning. By reducing financial risk and regulatory uncertainty, this approach encourages timely investment in infrastructure that benefits all customers.

[5] Minn. Stat. § 216B.03.

In summary, an advance determination of prudence is necessary to provide the regulatory certainty utilities need to pursue major infrastructure investments. It ensures accountability by requiring utilities to deliver projects as approved and to justify any cost overruns. We urge the Commission to adopt J.14–J.16 and reject J.13.

6. J.17

We, along with Fresh Energy, support J.17. No other stakeholders have taken a position.

7. J.18 and J.19

J.18 and J.19 are alternatives and either may be adopted with J.13 or J.14-J.16.

> J.18 An interested person may submit substantial evidence to rebut the Proactive Upgrade Proposal findings and conclusions in a cost recovery proceeding.

> J.19 An interested person may submit substantial evidence to rebut the Proactive Upgrade Proposal findings and conclusions in a cost recovery proceeding, to the extent that actual or updated projected costs exceed the prior estimate previously approved by the Commission.

We support J.19 and oppose J.18. The term "substantial evidence" in J.18 is too vague to provide meaningful guidance to utilities when implementing a project after it has been approved. Once a project has received Commission approval, it should not be subject to broad re-evaluation during cost recovery proceedings unless specific, foreseeable conditions arise—such as significant cost overruns.

J.19 appropriately limits the scope of re-examination to situations where actual or projected costs materially exceed the approved estimate. This provides a clearer and more predictable framework for utilities, enabling them to make informed decisions about whether and how to proceed with a project as its scope and costs evolve. Such clarity is essential for effective project planning and execution, and for maintaining regulatory certainty.

K. Section K – Cost Allocation

1. K.1-K.6

All stakeholders support K.1 and we do not oppose including the Department's proposed minor modifications to K.1. There is broad alignment among stakeholders on K.2 through K.6, which is a package. We support K.3 through K.6, and we also support K.2 as modified. All other stakeholders support K.3-K.6.

2. K.7-K.12

K.7-K.12 are intended to function as a package of cost allocation provisions. We oppose the adoption of provisions K.7 through K.12.

> K.7 Insofar as proactive upgrades are associated with forecasted needs associated with identifiable customers, those customers shall be considered Cost-Share Customers and shall be allocated costs consistent with existing CIAC policies.
>
> DOC K.7 Insofar as proactive upgrades are associated with forecasted needs associated with identifiable customers, those customers shall be considered Cost-Share Customers and shall be allocated costs ~~consistent with existing CIAC policies~~via a cost share fee.
>
> > K.7.a The proactive share of the eligible CIAC for small load additions from the residential class should be structured similarly to the 40 kW and under small DER cost share.
> >
> > DOC K.7a ~~The proactive share of the eligible CIAC~~Cost-share fee for small load additions from the residential class should be structured similarly to the 40 kW and under small DER cost share.
>
> K.8 For proactive upgrade projects serving large commercial and industrial customers, proactive upgrades will be tracked separately from other rate-base assets and their total cost allocated based on large commercial and industrial's aggregate contribution to need for proactive upgrade.
>
> DOC K.8 For proactive upgrade projects primarily serving large commercial and industrial customers, proactive upgrade ~~will be~~ costs shall be tracked separately from other rate base assets and ~~their total cost~~ allocated ~~based on large commercial and industrial's aggregate contribution to need for proactive upgrade.~~ to the large commercial and industrial classes contributing to the need for the upgrade.
>
> K.9 For upgrades primarily intended to enable load growth by residential and small commercial customers, traditional cost allocation methods in a rate case shall apply. Specifically, the utility shall record costs from the upgrades in their respective FERC accounts and allocate costs with cost allocators from the utility's most recent rate case.
>
> K.10 Insofar as proactive upgrade costs are recovered from customers through CIAC, those revenues shall be returned to ratepayers. Costs recovered through these tools should "pay down" the remaining unattributable proactive upgrade costs that are socialized to ratepayers.
>
> DOC K.10 Insofar as proactive upgrade costs are recovered from customers through ~~CIAC~~cost-share fees, those revenues shall be returned to ratepayers. Costs recovered through these tools should "pay down" the remaining unattributable proactive upgrade costs that are socialized to ratepayers.

> K.11 Proactive distribution upgrade projects, or portions of upgrade projects, that enable DG interconnection, shall assess an upfront $/kWac fee to Interconnection Cost-Share Customers seeking to interconnect generation.
>
> > K.11.a Fees shall continue to be collected beyond the original date of the forecasted need if capacity remains
> >
> > K.11.b Initial fees could be set to target recovering a certain threshold of the upgrade costs from interconnections, such as the $/kWac fee set higher than the forecasted amount, which could be applied for the first X% of capacity.
> >
> > K.11.c The existing small DER cost sharing program may be used to fund the upgrade fee.
>
> K.12 Insofar as proactive upgrade costs are recovered from customers through Interconnection Cost-Share Fees those revenues shall be returned to ratepayers. Costs recovered through this tool should "pay down" the remaining unattributable proactive upgrade costs that are socialized to ratepayers.

We oppose provisions K.7 through K.12 because they introduce project-specific cost allocation mechanisms that depart from established regulatory principles and create unnecessary complexity in utility cost recovery. These provisions attempt to assign costs based on the perceived beneficiaries of individual proactive upgrade projects, rather than treating such upgrades as part of the broader, integrated distribution system that benefits all customers. Our concerns are as follows:

1. *Departure from Established Cost Allocation Practices*. Under current regulatory frameworks, utility costs are allocated using cost allocators approved in general rate cases. These allocators are developed through rigorous analysis and stakeholder input, ensuring fairness, transparency, and consistency across customer classes. In contrast, K.7–K.12 propose ad hoc cost-sharing mechanisms—such as project-specific fees and customer-specific allocations—that would fragment the cost recovery process and undermine regulatory certainty.

2. *Mischaracterization of Upgrade Benefits*. Provisions K.7–K.12 attempt to categorize upgrades as serving either load growth or generation interconnection. In practice, however, most proactive upgrades enhance overall system capacity and flexibility, enabling both increased load and distributed energy resource (DER) adoption. Attempting to isolate the "primary" purpose of an upgrade is both artificial and impractical – and could lead to inequitable cost allocations that do not reflect the shared benefits of grid modernization.

3. *Risk of Discouraging Investment.* By introducing uncertainty around cost recovery and shifting financial risk onto specific customer groups, these provisions may discourage utilities from pursuing proactive upgrades. This could slow progress on critical infrastructure improvements needed to support electrification, resilience, and clean energy goals. A more stable and predictable cost recovery framework—based on system-wide benefits and traditional allocation methods—will better support long-term planning and investment.

4. *Revenue Neutrality and Ratepayer Protections.* While K.10 and K.12 propose returning cost-share revenues to ratepayers, this objective can be achieved more effectively through existing ratemaking processes. Utilities already account for CIAC and other contributions in rate cases, ensuring that revenues are properly credited and that ratepayers are not overburdened. Creating separate mechanisms for revenue return adds complexity without providing additional protections.

5. *The Distribution System is Dynamic.* The distribution system frequently evolves due to the granular and changing mix of customers it serves. After a proactive upgrade is completed, subsequent developments or shifting load patterns may require reconfigurations that change which customers are served by the affected feeder circuits or substations. As a result, structuring cost allocation based on the initial mix of customer classes is likely to become inaccurate over the life of the asset.

3. K.13-K.21

There appears to be little stakeholder disagreement on provisions K.13 through K.21. We oppose K.13 through K.19, and no other stakeholders have taken a position on these provisions. We also oppose K.20; the only other stakeholder to comment on it is MnSEIA, which supports it. Our concerns regarding K.20 are outlined in Section I.K.2.

4. K.22-K.24

K.22-K.24 are standalone options:

> K.22 Insofar as proactive upgrades are associated with forecasted needs associated with identifiable customers, those customers shall be allocated costs consistent with existing CIAC policies, and an upgrade shall not be eligible for the proactive process.

> K.23 [Utility's] existing CIAC policies include waiving service-transformer-related CIAC for customers with an EV who opt to participate in a managed charging program.
>
> K.24 For upgrades primarily intended to enable load growth by residential and small commercial customers, traditional cost allocation methods in a rate case shall apply. Specifically, the utility shall record costs from the upgrades in their respective FERC accounts and allocate costs with cost allocators from the utility's most recent rate case.

We oppose K.22-K.24 for the following reasons:

- *K.22 – Inconsistent with the Purpose of the Proactive Framework*. While we understand the OAG's concern about allocating costs for upgrades that may primarily benefit large commercial or industrial customers, the proactive framework is specifically 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.

- *K.23 and K.24 – Redundant with Existing Framework Elements*. These provisions reiterate cost allocation principles that are already addressed in Section A of the framework. Including them here adds unnecessary repetition without providing additional clarity or value.

5. K.25

K.25 and the alternative proposed by OAG seek to constrain cost allocation for certain proactive upgrades to the large commercial and industrial customer classes:

> K.25 For upgrades 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.
>
> 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.

We oppose both versions of K.25. While we understand the intent to shield other customer classes—such as residential customers—from bearing the cost of upgrades that may not directly benefit them, these proposals are not practicable in the context of how the distribution system or the regulatory compact operates.

- *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.

Attempting to isolate and assign costs based on a project's perceived primary beneficiaries would introduce complexity and undermine the integrated nature of the grid.

6. K.26

K.26, along with alternatives proposed by the OAG and the Department, seeks to mitigate adverse bill impacts on under-resourced customers and small businesses. We oppose all versions of K.26:

> K.26 If proactive upgrade costs are socialized to ratepayers, the utility shall identify and mitigate adverse bill impacts on under-resourced customers and/or small business by adjusting cost allocation within or among classes.
>
> OAG K.26 If proactive upgrade costs are socialized to ratepayers, the utility shall identify and mitigate adverse bill impacts on under-resourced customers and/or small businesses ~~by adjusting cost allocation within or among classes~~.
>
> DOC K.26 To the extent that ~~If~~ proactive upgrade costs are socialized to ratepayers, the utility shall identify and mitigate adverse bill impacts on under-resourced customers and/or small business by adjusting cost allocation within or among classes.

While we fully agree that affordability for under-resourced customers and small businesses is an important consideration, we do not believe that adjusting cost allocation is the appropriate or most effective mechanism to address these concerns.

- *Affordability impacts are more appropriately addressed during project evaluation,* as reflected in draft requirement G.10, which allows for consideration of customer impacts when determining whether a project should proceed.

- *There is no clear or practical mechanism* for implementing cost allocation adjustments specifically targeted at mitigating bill impacts for certain customer groups.

- *We do not support the use of custom class allocators* that differ from those approved in general rate cases. These allocators are developed through a transparent, data-driven process that ensures fairness and consistency across all customer classes.

Rather than modifying cost allocation frameworks, we believe affordability concerns should be addressed through targeted policy tools or programmatic support that complement the existing regulatory structure.

L. Section L – Capacity Reservation

Section L addresses capacity reservations, with subsections L.1 through L.6 presenting alternative approaches. Our comments focus on L.1, L.3, and L.6. We do not address L.2 and L.5–L.5b because we continue to oppose these provisions, and no other parties have taken a position. Similarly, we omit discussion of L.4–L.4.a, which we continue to support, as no other parties have commented on them.

L.1, L.3, and L.6 state:

> L.1 Capacity does not need to be reserved for a specific customer class.
>
> L.3 A percentage of the capacity of a proactive distribution upgrade may be reserved for under 40kWac DG to facilitate more efficient queue processing through the Priority Queue, if the proposal demonstrates that based on the customer make-up of the feeder, existing customers will benefit from a capacity reservation.
>
>> L.3.a [Utility] shall propose a capacity reservation for under 40kWac DG for each upgrade in a Proactive Upgrade Proposal with its filing.
>>
>> L.3.b Small DG (less than 40kWac) shall continue to be able to use the Small DER Cost Sharing Fund for service transformer and secondary upgrades at the existing funding levels and fees consistent with Cost Sharing Program.
>>
>> L.3.c [Utility] must seek PUC approval to implement this capacity reservation system and any specific Proactive Upgrade capacity reservation Proposal. If the utility's planning limit is invalidated, this agreement must be renegotiated.

L.6 [Utility] shall implement a capacity reservation system as follows:

> L.6.a **Generation**: Following a proactive DG hosting capacity upgrade, a minimum of 1 MW shall be reserved for the interconnection of systems below 40kWac. Where the installation of new DER systems larger than 40kWac does not impose new constraints on the interconnection of 1 MW of new DG smaller than 40kWac, such systems can be allowed to proceed with interconnection.
>
> L.6.b **Load**: 25% [or another percentage to be discussed] of the capacity from proactive upgrades shall be reserved for residential and small C&I customers and shall not be made available to new load additions of total size in excess of 250kWac [or another threshold to be discussed].
>
> L.6.c **Reservation Waiver**: For locations where new adoption from residential and small C&I customers is not reasonably anticipated (e.g., on feeders serving exclusively industrial loads), load and generation capacity reservations for residential and small C&I customers such areas may be waived or reduced.

Our positions are as follows:

<u>L.1 – Oppose with conditional support</u>

We oppose L.1 because it dismisses the need for any capacity reservations, which we believe are essential for ensuring equitable access to grid capacity—particularly for smaller customers seeking to adopt DER. Without a reservation mechanism, there is a risk that larger, faster-moving DER interconnection projects could monopolize available capacity, leaving smaller or community-based DER interconnection projects at a disadvantage.

However, if L.4 and L.4.a are not adopted, we would support L.1 as a fallback. In that case, a no-reservation approach would be preferable to implementing flawed or overly complex reservation systems that could hinder grid access or create administrative burdens.

<u>L.3 – Oppose</u>

We oppose L.3 and its subparts (L.3.a–L.3.c) because it proposes a feeder-specific capacity reservation system for DERs under 40kWac. While the intent to support small DER is commendable, the implementation would be highly complex and burdensome:

- *Feeder-by-feeder analysis* would require granular data analysis, ongoing updates as the distribution system is reconfigured over time, and extensive utility resources, which could delay project approvals and increase costs.

- *Customer confusion* could increase, as varying rules and reservation levels across feeders would make it difficult for developers and customers to understand their options.

In short, while we support the goal of ensuring access for small DER, this approach is not practical or scalable.

L.6 - Oppose

We oppose L.6 and its subparts (L.6.a–L.6.c) for several reasons:

- The 1 MW reservation for systems under 40kWac (L.6.a) is arbitrary. It does not account for the actual capacity of the feeder or substation transformer, which can vary widely. A one-size-fits-all threshold could result in either underutilization or over-allocation of capacity.
- The 25% load reservation for residential and small commercial and industrial (C&I) customers (L.6.b) is unnecessary. Utilities already have a statutory obligation to serve all load customers, and there is no evidence that these customers are currently being excluded from capacity access.
- The waiver provision (L.6.c) acknowledges that reservations may not be needed in all areas, which further underscores the arbitrary nature of the proposed thresholds.

Instead of fixed percentages or blanket reservations, we believe capacity planning should be guided by data-driven planning standards that reflect actual system needs and customer demand.

M. Section M - Reporting

1. M.1

All stakeholders support M.1.

2. M.2 and M.3

M.2, M.3, and an alternative version of M.3 proposed by the Department and OAG aim to clarify how reporting obligations should change once a project's cost-share window has closed:

> M.2 For projects where the cost share window has closed the utility shall no longer include them in the "all proactive upgrades" summary and may discontinue updates in the project-by-project reporting points.
>
> M.3 For projects where the cost-share window has closed, the utility may discontinue updates in the project-by-project reporting points under M.4 and M.5.
>
> DOC&OAG M.3 For projects where the cost-share window has closed, the utility may discontinue updates in the project-by-project reporting points under ~~M.4 and~~ M.5 and M.6.

We support the Department and OAG's broader interpretation and propose a slight clarification to ensure consistency across all reporting requirements. Our modifications are in blue redline format:

> Xcel Energy M.3 For projects where the cost-share window has closed, the utility may discontinue updates in the project-by-project reporting points under M.4 and M.6 ~~M.5~~.

Once a project's cost-share window closes, the Company will no longer collect cost-share fees from customers and will therefore stop tracking the data necessary to support ongoing reporting. As a result, updates would no longer be available for most reporting items in M.5 and M.6, and for at least one item in M.4—specifically, "Total $ and percent of project costs recovered from interconnection customers."

3. M.4-M.10

All stakeholders support M.4-M.10.

4. M.11

M.11 is a standalone requirement that we oppose:

> M.11 If the costs of previously approved proactive upgrades were not recovered within the cost-share window, [utility] shall provide a narrative explanation of why it was not able to recover the costs within the window. [Utility] shall also explain how it will improve its forecast or other procedures to avoid unnecessarily socializing costs.

The OAG and the Department supported this requirement without offering justification. We oppose this requirement because it is likely to apply to nearly every proactive upgrade project. Forecasting customer adoption and behavior over a 10–15 year period will inevitably involve some degree of error. It is unrealistic to expect any utility, individual, or organization to produce perfectly accurate long-term forecasts.

We instead support our modified M.12:

> Xcel Energy M.12 For projects that were accelerated, delayed, or abandoned following Commission approval, [utility] shall discuss the impact of the ~~that~~ change ~~on total proactive grid upgrade costs, cost allocation, and benefit allocation~~.

II. ATTACHMENT B

A. Requirements 1 and 2 – Timing of Phase 2

Requirements 1 and 2 discuss when Phase 2 should commence:

> 1. Phase 2 shall commence within 30 days of the Commission's written decision on Xcel Energy's 2025 Integrated Distribution Plan and follow the workgroup structure from Phase 1 with a goal of a Commission decision by Q2 of 2027.

> Xcel Energy 1. Phase 2 shall commence within 30 days of the Commission's written decision on Xcel Energy's 2025 Integrated Distribution Plan and follow the workgroup structure from Phase 1 with a goal of a Commission decision by ~~Q2~~Q4 of ~~2027~~2026.

> 2. Phase 2 shall commence within 30 days of the Commission's written decision on Xcel Energy's 2025 Integrated Distribution Plan and follow the workgroup structure from Phase 1 with a goal of a Commission decision by Q3 of 2027.

Xcel Energy respectfully opposes the timeline proposed in Requirement 1, which targets a Commission decision by Q2 of 2027, and Requirement 2, which targets a Commission decision by Q3 of 2027. After carefully considering the timeline, we recommend revising the goal to Q4 of 2026 instead. This adjustment is critical to ensure that any outcomes or directives resulting from Phase 2 can be meaningfully incorporated into the development of our 2027 IDP.

The IDP is a comprehensive and forward-looking document that requires significant lead time for planning, internal coordination, stakeholder engagement, and regulatory compliance. A Commission decision as late as Q2 2027 would not provide sufficient time to integrate any new requirements, insights, or structural changes into the 2027 IDP cycle. This could result in missed opportunities for alignment with Commission priorities and stakeholder expectations, and potentially delay the implementation of important grid modernization or equity-focused initiatives.
By targeting a decision by Q4 2026, the Commission would enable a more practical and effective planning timeline. This would allow Xcel Energy to:

- **Incorporate Commission guidance** into the early stages of IDP development

- **Engage stakeholders** with a clear understanding of regulatory expectations
- **Ensure alignment** between Phase 2 outcomes and the 2027 IDP content
- **Avoid duplicative or rushed efforts** that could compromise the quality or feasibility of implementation

For these reasons, we strongly support our proposed revision to Requirement 1 and believe it better serves the goals of the Commission and stakeholders.

B. Requirement 3 – Coordination with the Reactive-DER Process

We oppose Requirement 3 in its entirety:

> 3. Coordination of the Proactive Distribution Upgrade Process with the Reactive-DER Cost Sharing Process:
>
> > 3.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.
> >
> > 3.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.
> >
> > 3.c The proactive upgrades at such eligible locations must comply with all other aspects of the proactive upgrade framework

The activities described—such as sizing equipment to account for forecasted needs during the development of a reactively-driven project—are already part of our standard utility planning and operational practices. These decisions are made in real time to ensure timely and efficient interconnection and system reliability, and they do not belong within the scope of the proactive upgrade framework.

The proactive framework should be reserved for projects that go beyond traditional utility planning and operational practices, as defined elsewhere in this framework. Including historically standard practices within the proactive framework would blur the distinction between proactive and reactive planning, create confusion, and potentially delay necessary upgrades.

Moreover, reactive upgrade decisions must be made without delay to meet immediate system needs. Waiting for the next proactive upgrade cycle to evaluate these decisions would introduce unacceptable delays and could compromise system performance and DER integration timelines.

For these reasons, we recommend removing Requirement 3 from the framework.

C. Requirements 4 and 8 – Forecasting and Identification of Proactive Upgrades

All parties support adopting Requirements 4 and 8.

D. Requirement 5 – Flexible Interconnection

Requirement 5 states: Flexible Interconnection.

We oppose the inclusion of Flexible Interconnection in the Proactive Distribution Grid Upgrades Framework. Flexible Interconnection is not an infrastructure upgrade—it is a method for avoiding or deferring the need for upgrades by managing system constraints through operational flexibility. As such, it does not align with the purpose of the proactive framework, which is intended to identify and implement physical infrastructure investments that expand hosting capacity in anticipation of future needs.

E. Requirement 6 – Cost Recovery

Requirement 6 states: Advanced cost allocation and cost recovery methodologies, including export tariffs.

We oppose Requirement 6 for several key reasons. Introducing new or advanced cost allocation and recovery methodologies—particularly those that diverge from long-standing regulatory constructs—would present significant challenges:

1. *Regulatory Complexity and Uncertainty*. Established cost allocation frameworks are industry standard and have been developed through extensive regulatory proceedings and are grounded in principles of fairness, transparency, and consistency. Departing from these frameworks would require substantial regulatory review and approval, potentially involving new dockets and stakeholder processes. This would introduce uncertainty and delay into the implementation of proactive upgrades.

2. *Lack of Justification for Differential Treatment*. It is unclear why proactive upgrade projects should be treated differently from other distribution system investments in terms of cost allocation. All infrastructure investments—whether proactive or reactive—ultimately serve to maintain and enhance

system reliability, safety, and capacity. Applying a separate cost recovery methodology to proactive upgrades could create inconsistencies in how costs are assigned to customers and undermine the principle of equitable treatment.

3. *Risk of Cost Shifting and Inequity*. Without careful design and oversight, advanced cost allocation methods could result in unintended cost shifts between customer classes or between DER developers and general ratepayers. This could raise concerns about fairness and affordability, particularly if certain customers are disproportionately impacted by new charges.

In summary, while we support efforts to improve cost transparency and efficiency, we believe Requirement 6 introduces unnecessary complexity and risk of unintended consequences from deviating from industry standard and Commission accepted cost recovery protocols. Proactive upgrades should continue to be recovered through existing, well-established regulatory mechanisms that ensure consistency and fairness.

F. Requirement 7 – Capacity Reservations

All parties support Requirement 7, but the Department and OAG and proposed additional revisions. All proposed versions of Requirement 7 are listed below:

> 7. Additional discussion on system wide capacity reservations.
>
> DOC 7. Additional discussion on capacity reservations, to include system wide capacity reservations.
>
> OAG 7. ~~Additional discussion on~~ Whether system wide capacity reservations for proactive upgrades are necessary or appropriate, and, if so, under what conditions and how they should be determined.

We do not oppose these revisions.

G. MNSEIA Proposed Requirement 9 – Cost Envelope

MNSEIA has proposed a new requirement: Implementation of a cost envelope to prevent cost overruns, which we oppose.

Our understanding of MNSEIA's proposal is that it would establish a hard 25 percent cap for approved upgrade projects, beyond which utilities would not be permitted to recover costs.

We oppose this proposal for several reasons:

1. *Introduces Unnecessary Risk*. Forecasting upgrade costs involves inherent uncertainty due to evolving system conditions, permitting timelines, material costs, and labor availability. A rigid cost envelope could expose utilities to financial risk if actual costs exceed the cap, even when those overruns are due to factors beyond their control. For example, these could include supply-chain constraints and challenges due to the evolving federal policy landscape.

2. *Reduces Planning Flexibility*. Utilities need the ability to adapt plans as new information becomes available. A fixed cost cap could constrain the ability to respond to changing system needs or to implement more efficient or beneficial solutions that emerge during the planning or construction process.

3. *Discourages Proactive Investment*. Utilities may become hesitant to pursue forward-looking or innovative upgrades if they risk being penalized for cost variability. This could lead to underinvestment in grid infrastructure, ultimately harming long-term system reliability and customer outcomes.

In summary, while we understand the desire to manage costs and provide transparency, we believe this proposal would have unintended consequences that outweigh its potential benefits. A more flexible, collaborative approach to cost management would better serve all stakeholders.

III. ADDITIONAL CONSIDERATIONS

In this section, we address other recommendations or questions raised by the Department and Fresh Energy.

A. Mandatory Application of the Framework and New IDP Filing Requirement

The Department raises two additional considerations: (1) requiring all utilities operating under an approved proactive planning framework to follow the Framework and include a new filing requirement in their IDP, and (2) requiring utilities to justify why each DER project proposed under the Proactive Upgrades Framework could not instead be pursued through the Reactive Framework.

The Department recommends that the Commission require all utilities to follow the Proactive Distribution Grid Upgrades framework and evaluate their systems for proactive upgrades—regardless of whether a utility proposes any proactive upgrade projects for Commission review. Specifically, the Department proposes a new filing requirement within the IDP for any utility operating under an approved Proactive Planning Framework. This requirement would include:

- 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.

We respectfully oppose the Department's recommendation to make the framework mandatory for all utilities and to require additional forecasting disclosures in the IDP, for the following reasons:

1. *Existing Forecasting Requirements Are Robust and Sufficient.* Utilities are already required to include detailed forecasts in their IDPs, including projections of load growth and DER adoption. These forecasts are developed using established methodologies and are subject to stakeholder review. They provide a solid foundation for identifying long-term system needs and planning both reactive and proactive upgrades.

   Adding a new, duplicative forecasting requirement would not meaningfully improve transparency or planning outcomes. Instead, it risks creating confusion by introducing overlapping or inconsistent data sets.

2. *Forecast Uncertainty is a Legitimate Planning Constraint.* Forecasting at the feeder or substation level is inherently uncertain, especially in areas with volatile customer behavior, limited historical data, or emerging technologies. In some cases, a utility may choose not to propose a proactive upgrade precisely because the forecast is too uncertain to justify investment.

   Requiring utilities to publish forecast results for these locations—despite not proposing any action—could mislead stakeholders into thinking that upgrades are warranted or imminent. This could create false expectations, misallocate stakeholder attention, and undermine confidence in the planning process.

3. *The Draft Framework Already Ensures Transparency.* The draft framework already includes a provision requiring utilities to disclose which locations were analyzed and considered for proactive upgrades, even if no proposal was submitted. This strikes the right balance between transparency and practicality. By requiring utilities to explain their decision-making process—including why certain locations were not selected—the framework provides stakeholders with meaningful insight without mandating the release of potentially misunderstood forecast data.

4. *Additional Reporting Requirements Would Increase Burden Without Clear Benefit.* The proposed requirement would impose a significant additional workload on utilities, including the need to prepare, validate, and explain detailed forecasts for locations where no action is being taken. This would divert resources away from higher-value planning and implementation activities.

   Moreover, the value of this additional information is unclear. It is not evident how publishing forecast data for non-actionable locations would improve stakeholder understanding, regulatory oversight, or grid outcomes.

5. *Flexibility Is Essential for Effective Proactive Planning.* Proactive planning is most effective when utilities have the flexibility to focus on locations where the data is strong, the need is clear, and the benefits are compelling. Mandating a uniform approach across all utilities and all potential upgrade locations would reduce this flexibility and could lead to less efficient or less targeted investments.

In sum, we support thoughtful, transparent, and data-driven planning. However, we believe the Department's proposal to make the Framework mandatory and require additional forecasting disclosures is unnecessary, potentially confusing, and administratively burdensome. The existing IDP requirements and the transparency provisions in the draft Framework already provide a strong foundation for proactive planning.

We urge the Commission to preserve utility flexibility, avoid duplicative reporting, and focus on actionable, high-confidence planning efforts that deliver real value to customers and the grid.

B. Justification for Using the Proactive Framework Instead of the Reactive Framework

We oppose the Department's proposal to require utilities to justify, on a project-by-project basis, why each DER project proposed under the Proactive Distribution Grid Upgrades Framework could not be pursued through the Reactive Framework. This requirement is unnecessary, administratively burdensome, and counterproductive to the goals of proactive planning. Our concerns are as follows:

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 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.

We urge the Commission to reject the Department's proposal to require utilities to justify why each proactive DER project could not be pursued reactively. Instead, the Commission should support a planning environment that encourages forward-looking investment, enables utilities to act on the best available data and system insights, and reduces administrative burden.

C. Clarifying the Scope of the Proactive Upgrade Framework

Fresh Energy requested our response on the following two questions: (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?; and (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?

While we appreciate Fresh Energy's continued engagement, we believe these questions extend beyond the intended scope of this Framework.

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.

Xcel Energy Preferred Proactive Distribution Upgrade Framework

A. Introduction

The Commission establishes the following framework for proactive distribution upgrades for [utility] to achieve the following goals:

A.2 Proactively plan for the distribution system upgrades necessary to ~~meet state energy policy requirements and goals~~ enable customer DER and electrification adoption, considering state energy policy requirements and goals.

A.3 Meet customer expectations by reducing or eliminating the wait time to interconnect DERs and new load to the extent reasonably possible.

A.5 Protect ratepayers by establishing a ~~rigorous~~ review of proposed proactive investments to ~~ensure they do not cause undue risk costs or~~ minimize the risk of stranded assets or projects that result in inequitable distribution of costs or benefits.

A.7 To the extent reasonably possible, maximize the benefits to the distribution system while minimizing the costs.

A.9 Limit cost impacts from unreasonable forecast inaccuracies.

The Commission establishes the following principles to guide allocation of the costs of proactive upgrades:

A.10 Limit deviations from traditional cost allocation and recovery processes to the extent possible.

A.11 Costs should be allocated to the customers or classes causing the costs, when appropriate.

B. Definitions

The Commission adopts the following definitions for the purposes of this framework:

B.2 Cost-Share Customer: a customer who applies to interconnect either load or generation at a location served by a Proactive Distribution Upgrade with an open cost-share window and is responsible for paying a Cost-Share Fee, unless otherwise specified in approved tariffs.

B.3 Cost-Share Fee: the amount a Cost-Share Customer pays to access a location served by a Proactive Distribution Upgrade.

B.4 Cost-Share Window: the period during which Cost-Share Fees are collected from Cost-Share Customers.

Note: Original red-line is noted in red; Xcel Energy proposed modifications are noted in blue. Sections C.6 and F.1 are highlighted to reflect additional revisions we are proposing in these Reply Comments in response to stakeholder feedback.

B.5 Distribution Capacity Upgrade: A distribution system upgrade at the substation or feeder level that increases hosting capacity for load and/or generation on the distribution system.

B.6 Distributed Energy Resource (DER): Supply and demand side resources that can be used throughout an electric distribution system to meet energy and reliability needs of customers; can be installed on either the customer or utility side of the electric meter. This definition for this filing may include, but is not limited to: distributed generation, energy storage, electrified end uses that can be used as a resource, demand side management, and energy efficiency.

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~~,~~ and operates in parallel with the utility~~, and is eligible for interconnection under the Minnesota Distributed Interconnection Procedures~~.

B.9 Electrification: the conversion of an energy-consuming device, system, or sector from non-electric sources of energy to electricity. This includes but is not limited to transportation electrification, cooking appliances, space heating and cooling, water heating, and industrial processes.

B.10 Forecasted/Proactive Hosting Capacity: The amount of DG or load that distribution equipment can host without exceeding thermal, voltage, protection, or other thresholds under forecasted system conditions.

B.11 Hosting Capacity: The amount of DG or load that distribution equipment can host without exceeding thermal, voltage, protection, or other thresholds under existing system conditions.

B.12 Integrated Distribution Plan: the biennial report established in Docket E002/CI-18-251 and as currently outlined in the filing requirements available [here].

B.13 Priority Queue: The queue for "customer-sited" Interconnection Applications up to 40 kWac and applications that are a part of the Solar for Schools or Solar on Public Buildings legislative programs that comply with the 120% rule, as detailed on tariff sheet 10-81.5.

B.15 Proactive Upgrade Proposal: one or more Proactive Distribution Upgrades submitted for Commission approval under the Proactive Distribution Upgrade Framework. In the context of this framework, the Proactive Distribution Upgrades submitted in the Proactive Upgrade Proposal would not be considered prudent under existing distribution planning practices due to the proactive nature of the projects.

B.16 Proactive Distribution Upgrade: a distribution upgrade made solely based on a forecasted need outside a utility's traditional planning cycle.

Note: Original red-line is noted in red; Xcel Energy proposed modifications are noted in blue. Sections C.6 and F.1 are highlighted to reflect additional revisions we are proposing in these Reply Comments in response to stakeholder feedback.

B.17 Small DER Cost Sharing Fund: [Utility's] cost sharing fund for MN DIP applications of 40kW$_{ac}$ or less as detailed on [tariff sheet 10-81.4].

C. Process

C.1 [Utility] may file a Proactive Upgrade Proposal in conjunction with its Integrated Distribution Plan (IDP) due on November 1 of odd numbered years. The Proactive Upgrade Proposal shall be evaluated through the same docket and process as the IDP but is not part of the IDP.

C.2 The Proactive Upgrade Proposal may include proactive distribution upgrades that have not been initiated and shall begin construction within five years from the date of the filing. It may also contain proactive distribution upgrades that are not specific to a single location but shall upgrade the same type of asset(s) across multiple locations.

C.3 The Proactive Upgrade Proposal must demonstrate alignment with the framework, and the Commission shall review and approve, deny, or modify the Proposal with a goal of completion within 12 months from the date of the initial filing.

C.4 [Utility] is not obligated to initiate a project if it is approved in the Proactive Upgrade Proposal. If [utility] does not proceed with an approved project, it shall explain why and the impact on the overall program budget with its Annual Report, as described in L. Reporting - 9 below.

C.5 Previously approved projects do not require reapproval in subsequent Proactive Upgrade Proposal evaluations unless circumstances have changed significantly. Significant changes would be considered scope changes to the project that would substantially impact overall project cost.

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.

C.8 As addressed further in Section J: Cost Recovery, the Utility must pursue cost recovery through a separate proceeding for any incurred Proactive Upgrade Proposal expenditures.

C.9 The Proactive Upgrade Framework is subject to refinement through the Proactive Grid Upgrade Workgroup. The Proactive Grid Upgrade Workgroup shall be convened by Commission Staff and shall meet as necessary to refine and improve the Proactive Upgrade Framework. This shall include Phase 2 of the framework development in 2025 and 2026 to ~~un~~resolve~~d~~ issues left out of Phase 1.

Note: Original red-line is noted in red; Xcel Energy proposed modifications are noted in blue. Sections C.6 and F.1 are highlighted to reflect additional revisions we are proposing in these Reply Comments in response to stakeholder feedback.

C.10 [Utility] shall engage with interested stakeholders prior to the forecast being finalized and used to identify locations of proposed upgrades. This outreach shall be conducted during the first half of even-numbered years, starting in 2026.

C.10.a [Utility] shall share the initial results of its forecast and identify preliminary regions where upgrades may be needed.

C.10.b [Utility] shall give stakeholders the opportunity to send in written feedback on its initial forecast.

C.10.c Stakeholder feedback should focus on identifying geographic areas that have a higher likelihood to adopt DG and electrification that may not be represented in the utility's initial forecast.

C.10.d Utility shall provide a high-level summary of stakeholder engagement completed and feedback and where it was incorporated into the forecasting for the Proactive Upgrade Proposal, and if not, why not.

C.10.e Stakeholders with similar views are encouraged to file joint feedback with [utility].

D. Baseline Information

The following information should be provided with the IDP in which a Proactive Upgrade Proposal is submitted:

D.1 The types of upgrade projects and programs that fit within the framework and are currently considered when developing proposals. This may change over time based on utility capability.

D.2 Issues the potential project or program solves.

D.3 General range of cost for each type of upgrade.

D.4 An outline of future upgrade options, such as storage, and on what timeline they may be available.

D.5 A summary of upgrades that were previously approved but have since been accelerated, delayed, or abandoned due to a change in need since the last filing.

E. Forecast

E.1 [Utility] shall provide a base case forecast, as well as sensitivities that include higher and lower adoption of DERs and ~~electrification~~ customer loads than expected in the base case. [Utility] shall recommend which forecast should be adopted and explain why it thinks that forecast should be the case toward which to plan and why.

Note: Original red-line is noted in red; Xcel Energy proposed modifications are noted in blue. Sections C.6 and F.1 are highlighted to reflect additional revisions we are proposing in these Reply Comments in response to stakeholder feedback.

E.2 Where possible, the following load and DER components shall be differentiated in the forecast data provided: distributed solar PV, CSGs, distributed energy storage, energy efficiency, demand response, electric vehicles, and electrification of space, water, and process heating.

E.3 For each of the DER components above, [utility] shall provide a discussion of each essential assumption made in preparing the forecast, including assumptions regarding customer adoption rates, cost trends, and relevant policy drivers. [Utility] should include any sensitivity analyses used to test these assumptions.

E.4 In addition to the existing IDP load and DER forecast requirements, [Utility] shall submit its forecast results for generation and peak loads at the feeder/substation level for all locations associated with proposed proactive distribution upgrades ~~and locations that the utility analyzed but decided not to upgrade~~.

E.5 All proposed proactive upgrades shall be based on a forecasted need identified in the forecast between years five and ten, unless the anticipated lead time for an upgrade project exceeds ten years.

E.6 The forecast shall include an assessment of existing available hosting capacity for generation and load to the same extent as is shared in the utility's Hosting Capacity Analysis results.

F. Potential Sites for Proactive Upgrades

A utility must include in any Proactive Upgrade Proposal filing:

F.1 The criteria used to identify potential sites for proactive distribution upgrades, including a discussion of feedback received from stakeholders under Section ~~C.8~~ C.10 - Stakeholder Outreach.

F.2 A list of sites that [utility] may consider for future proactive distribution upgrades.

F.3 A list of proposed proactive distribution upgrades, including identifying any changes to upgrade locations since the last submission.

F.4 A narrative description or analysis of the impact of the proposed proactive distribution upgrades on Environmental Justice Areas, as defined by Minn. Stat. §216B.1691, Subd. 1 (e).

F.5 The total capital cost of all proposed upgrades and the projected total lifetime revenue requirements.

F.6 For each site where [utility] is proposing an upgrade, [utility] must provide:

Note: Original red-line is noted in red; Xcel Energy proposed modifications are noted in blue. Sections C.6 and F.1 are highlighted to reflect additional revisions we are proposing in these Reply Comments in response to stakeholder feedback.

F.6.a Expected type of upgrade.

F.6.b Narrative description for why the proposed upgrade or group of upgrades has been selected for the proactive upgrade process.

F.6.c Estimated upgrade cost and duration of construction.

F.6.d Increase in load and generation capacity expected to result from the proposed upgrade.

F.6.e Forecasted period before another upgrade is anticipated to be needed at the same site.

F.6.f Magnitude of forecasted growth (load or generation) and capacity gap driving the need for the proposed upgrade.

F.6.g Classes or characteristics of load or generation driving the need for the proposed upgrade.

F.6.h A quantitative or qualitative level of confidence of the forecasted need, and/or sensitivity of the forecasted need to deviations from the forecast, driving the need for the specific project. This may include any information gathered from communities, developers, customers (for example if large fleet owners, or other industrial/commercial building customers) and others that informed selection of the site.

F.6.i Identification of any known additional benefits resulting from the upgrade.

F.6.j Identification of planned capital investment or maintenance work to be coordinated with the proposed proactive distribution upgrade (where appropriate).

F.7 For sites that the utility analyzed but ultimately decided not to upgrade, the reasons the utility decided not to propose upgrades at that site.

F.8 For upgrades that are proposed as part of a longer-term plan, [utility] shall provide an assessment of whether they are expandable and whether there would be any potential benefits or costs from doing repeated work in the same area.

G. Proactive Upgrade Proposal Evaluation Criteria

Each proposed proactive distribution upgrade shall be evaluated using the following criteria, with the utility providing such information and evaluation as part of its filing:

G.1 The total capital cost of the proposed upgrade and its projected total lifetime revenue requirement.

G.2 The overall capacity gained for both load and generation.

G.3 The cost per unit of capacity gained.

G.4 The lead time for the upgrade.

G.7 The degree of certainty, qualitative or quantitative, of the forecast components driving the forecasted need at that location, and any additional certainty in the magnitude/scale of investment provided by direct customer engagement.

G.8 The remaining estimated useful life of the assets proposed to be replaced.

G.9 The estimated number of years beyond the timing of the upgrade that the project would meet the forecasted capacity needs at that location.

G.10 Narrative description or analysis of the impact of the proposed proactive distribution upgrade projects, including impacts on Environmental Justice Areas, as defined by Minn. Stat. §216B.1691, Subd. 1 (e).

G.11 The benefits additional to increased hosting capacity realized from the upgrade, if any, to reliability, resilience, safety, and asset health, and the value of those benefits, where known.

G.12 How any additional planned work would be coordinated with the proposed proactive distribution upgrade (where appropriate).

G.13 The extent to which the upgrade would facilitate progress toward greenhouse gas emission reduction targets.

G.15 Which desired outcomes of the proactive planning process would be facilitated by the proposed upgrade.

G.16 Feasibility of the projected upgrade project timeline including any foreseeable risks to the timeline.

H. Proposal for non-location specific proactive measures

H.1 The utility 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.

J. Cost Recovery

As indicated in Section C.8 regarding Process, [Utility] must pursue cost recovery through a separate proceeding for any incurred Proactive Upgrade Proposal expenditures.

Note: Original red-line is noted in red; Xcel Energy proposed modifications are noted in blue. Sections C.6 and F.1 are highlighted to reflect additional revisions we are proposing in these Reply Comments in response to stakeholder feedback.

Cost Recovery Mechanism

J.3 Expenditures for approved proactive upgrades shall be tracked as regulatory assets and~~/or~~ receive deferred accounting treatment to ensure that the costs of the upgrades are transparently accounted for and ~~can~~ are eligible to be recovered.

J.4 All cost-share fees collected from Cost-Share Customers shall be returned to ratepayers as an offset to the revenue requirements of proactive upgrade capital investments.

Cost Share Window

J.7 Each approved Proactive Distribution Upgrade shall have a Cost Share Window that starts the year that the Proactive Distribution Upgrade project is placed in-service. The duration of the Cost Share Window shall be until 5 years after the anticipated need date for the Proactive Distribution Upgrade at the time of approval. During the Cost Share Window, Cost-Share Fees from Cost-Share Customers act as an offset to the revenue requirements of all Proactive Distribution Upgrades.

J.8 Upon completion of the project, the total costs of the upgrade are placed into rate base. ~~At the end of the Cost Share Window, any remaining costs that have not been offset by Cost Share Fees are placed into ratebase and no longer subject to this cost sharing program.~~

J.9 Interconnecting customers that apply to interconnect on or before the cost share window end date are Cost-Share Customers. For generation interconnections, the date of applying to interconnect shall be the Deemed Complete date.

Prudency Review

J.14 The Commission's Proactive Upgrade Proposal decision constitutes an advance determination of prudence for the projects approved in the Proactive Upgrade Proposal.

J.15 If a project receives advanced determination of prudence, this means that at the time cost recovery is being considered, costs that align with the original proposal cannot be deemed imprudent.

J.16 If the Commission does not provide an advanced determination of prudence for the project, then for that reason alone, the utility may choose not to proceed with the project.

J.17 Up until the point that a previously approved project is canceled or rescinded by Commission Order, the utility is entitled to recover all costs that have been prudently incurred, not exceeding the previously approved amount.

J.19 An interested person may submit substantial evidence to rebut the Proactive Upgrade Proposal findings and conclusions in a cost recovery proceeding, to the extent that actual or updated projected costs exceed the prior estimate previously approved by the Commission.

Note: Original red-line is noted in red; Xcel Energy proposed modifications are noted in blue. Sections C.6 and F.1 are highlighted to reflect additional revisions we are proposing in these Reply Comments in response to stakeholder feedback.

K. Cost Allocation

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 change in cost-sharing responsibility.

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~~, and pay down the assets until~~ which will be applied as an offset to the total revenue requirements of all Proactive Distribution Upgrade projects with an open cost share window ~~has been paid off~~.

K.3. When new Proactive Upgrade Proposals are approved, the total kWac of capacity added and total cost of the newly approved Proactive Distribution Upgrades shall be added respectively to the totals of the previously approved Proactive Distribution Upgrades. The resulting new total kWac of capacity added and total cost of all Proactive Distribution Upgrades shall be used to calculate the new $/kWac fee that shall be charged to any Cost-Share Customers beginning after the date the new Proactive Upgrade Proposal is approved.

K.4 Any DG interconnections that are subject to the Priority Queue shall not be Cost-Share Customers.

K.5 Load interconnections that are demand metered shall be Cost-Share Customers. Load interconnections that are not demand metered shall not be Cost-Share Customers.

K.6 Any Proactive Distribution Upgrade costs recovered from ratepayers shall be treated consistent with approved rate case allocators and established revenue requirement procedures.

L. Capacity Reservation

L.4 [Utility] shall implement a system-wide capacity reservation for small DG to facilitate more efficient queue processing through the Priority Queue.

L.4.a Small DG (less than 40kW$_{ac}$) shall continue to be able to use the Small DER Cost Sharing Fund for service transformer and secondary upgrades at the existing funding levels and fees consistent with the Cost Sharing Program.

M. Reporting

M.1 [Utility] must file reports that include the following information and data to the greatest extent practicable. Where [utility] is not able to provide the required information, the

Note: Original red-line is noted in red; Xcel Energy proposed modifications are noted in blue. Sections C.6 and F.1 are highlighted to reflect additional revisions we are proposing in these Reply Comments in response to stakeholder feedback.

Company shall explain why it is unable to do so. Such reports must be filed annually on November 1 as part of [utility's] Integrated Distribution Plan or Annual Update. Where applicable, [utility] must include data in spreadsheet (.xlsx) format. If [utility] also files a PDF version of spreadsheet data, it must be filed as an attachment in a separate document instead of being merged with the main report.

M.3 For projects where the cost-share window has closed, the utility may discontinue updates in the project-by-project reporting points under M.4 and M.6 ~~M.5~~.

M.4 For all proactive upgrades –

	Approved	Development	Construction	Completed	Total
Number of projects					
Upgrades in Environmental Justice Communities					
Total $ approved					
Total $ spent					
Total $ and percent of project costs recovered from interconnection customers					
Total incremental generation hosting capacity gained					
Total incremental load hosting capacity gained					

Note: Original red-line is noted in red; Xcel Energy proposed modifications are noted in blue. Sections C.6 and F.1 are highlighted to reflect additional revisions we are proposing in these Reply Comments in response to stakeholder feedback.

M.5 By upgrade project –

	[Project Name]	[Project Name]	[Project Name]
Year Proposed	e.g. 2025 Proposal		
Located in EJ Community (y/n)			
Anticipated completion year at time of proposal			
Date cost share window closed (actual or predicted)			
Project status (approved, development, construction, completed, terminated)			
Year completed or current anticipated year of completion			
Total incremental generation hosting capacity gained			
Utilization of capacity post upgrade (generation)			
Total incremental load hosting capacity gained			
Utilization of capacity post upgrade (load)			
Total $ approved			
Total $ spent			
Total $ and percent of project costs recovered from interconnecting customers (load or generation)			

M.6 DER additions (Fill out table for each completed project)
[Project Name]

	40kW and under (BTM)	Over 40kW (BTM)	Front of the Meter	Total
Number of DERs added since project completion				
Solar				
Battery				
Other (Specify)				
Capacity of DERs added since project completion				
Solar				
Battery				
Other (Specify)				

M.7 For each completed project, the current peak load, forecasted peak load, and any known load additions by load type (Fleet EV charging, DCFC fast charging, etc.) and customer class

Note: Original red-line is noted in red; Xcel Energy proposed modifications are noted in blue. Sections C.6 and F.1 are highlighted to reflect additional revisions we are proposing in these Reply Comments in response to stakeholder feedback.

M.8 A comparison of Load and DG added since project completion with the forecast from the Proactive Upgrade Proposal.

M.9 Any additional narrative information, by project or portfolio, on the status of the project, cost deviations from the approved amount, and any delays in implementation and the cause for the delays.

M.10 For any approved projects that did not proceed, an explanation of why and what the impact is on the overall program budget.

M.12 For projects that were accelerated, delayed, or abandoned following Commission approval, [utility] shall discuss the impact of the ~~that~~ change ~~on total proactive grid upgrade costs, cost allocation, and benefit allocation~~.

Note: Original red-line is noted in red; Xcel Energy proposed modifications are noted in blue. Sections C.6 and F.1 are highlighted to reflect additional revisions we are proposing in these Reply Comments in response to stakeholder feedback.

Certificate of Service

I, Joshua DePauw, hereby certify that I have this day served copies of the foregoing document on the attached list of persons.

xx by depositing a true and correct copy thereof, properly enveloped with postage paid in the United States mail at Minneapolis, Minnesota

xx electronic filing

Docket No. E002/CI-24-318

Dated this 2nd day of June 2025

/s/
____
Joshua DePauw
Regulatory Administrator

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
1	Brian	Allen	brian.allen@allenergysolar.com	All Energy Solar, Inc		1642 Carroll Ave Saint Paul MN, 55104 United States	Electronic Service		No	24-318E002-CI-24-318
2	Anjali	Bains	bains@fresh-energy.org	Fresh Energy		408 Saint Peter Ste 220 Saint Paul MN, 55102 United States	Electronic Service		No	24-318E002-CI-24-318
3	Jared	Ballew	jared.ballew@ev.energy	EV.ENERGY CORP		726 18th St. Des Moines IA, 50314 United States	Electronic Service		No	24-318E002-CI-24-318
4	Shay	Banton	shayb@irecusa.org	Interstate Renewable Energy Council		600 H Street NE Apt. 341 Washington DC, 20002 United States	Electronic Service		No	24-318E002-CI-24-318
5	Mathias	Bell	mathias@weavegrid.com	WeaveGrid		375 Alabama Street, Suite 325 San Francisco CA, 94110 United States	Electronic Service		No	24-318E002-CI-24-318
6	Ed	Brolin	ed.brolin@rwe.com	RWE Clean Energy		100 Summit Lake Drive Suite 210 Valhalla NY, 10595 United States	Electronic Service		No	24-318E002-CI-24-318
7	Eric	Clement	eclement@mnpower.com	Minnesota Power		null null, null United States	Electronic Service		No	24-318E002-CI-24-318
8	Joshua	Cohen	josh.cohen@swtchenergy.com	SWTCH Energy, Inc.		Greentown Labs 444 Somerville Avenue Somerville MA, 02143 United States	Electronic Service		No	24-318E002-CI-24-318
9	Steve	Coleman	stevecolemanpuma@gmail.com			231 Winifred St W Saint Paul MN, 55107 United States	Electronic Service		No	24-318E002-CI-24-318
10	Generic	Commerce Attorneys	commerce.attorneys@ag.state.mn.us		Office of the Attorney General - Department of Commerce	445 Minnesota Street Suite 1400 St. Paul MN, 55101 United States	Electronic Service		Yes	24-318E002-CI-24-318
11	George	Damian	gdamian@cleanenergyeconomymn.org	Clean Energy Economy MN		13713 Washburn Ave S Burnsville MN, 55337 United States	Electronic Service		No	24-318E002-CI-24-318
12	Cody	Davis	cdavis@epeconsulting.com	Electric Power Engineers (ELPC/VS)		null null, null United States	Electronic Service		No	24-318E002-CI-24-318
13	Danielle	DeMarre	danielle.demarre@allenergysolar.com	All Energy Solar		1264 Energy Lane St Paul MN, 55108 United States	Electronic Service		No	24-318E002-CI-24-318

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
14	Timothy	DenHerder Thomas	timothy@cooperativeenergyfutures.com	Cooperative Energy Futures		3500 Bloomington Ave. S Minneapolis MN, 55407 United States	Electronic Service		No	24-318E002-CI-24-318
15	James	Denniston	james.r.denniston@xcelenergy.com	Xcel Energy Services, Inc.		414 Nicollet Mall, 401-8 Minneapolis MN, 55401 United States	Electronic Service		No	24-318E002-CI-24-318
16	Diane	Dietz	diane.dietz@state.mn.us		Department of Commerce	Suite 280 85 Seventh Place East St. Paul MN, 55101-2198 United States	Electronic Service		No	24-318E002-CI-24-318
17	William	Ehrlich	wehrlich@tesla.com	Tesla, Inc.		3500 Deer Creek Rd Palo Alto CA, 94304 United States	Electronic Service		No	24-318E002-CI-24-318
18	John	Farrell	jfarrell@ilsr.org	Institute for Local Self-Reliance		2720 E. 22nd St Institute for Local Self-Reliance Minneapolis MN, 55406 United States	Electronic Service		No	24-318E002-CI-24-318
19	Sharon	Ferguson	sharon.ferguson@state.mn.us		Department of Commerce	85 7th Place E Ste 280 Saint Paul MN, 55101-2198 United States	Electronic Service		No	24-318E002-CI-24-318
20	Allen	Gleckner	agleckner@elpc.org	Environmental Law & Policy Center		35 E. Wacker Drive, Suite 1600 Suite 1600 Chicago IL, 60601 United States	Electronic Service		No	24-318E002-CI-24-318
21	Tim	Gross	tgross@fuelingmn.com	Fueling Minnesota		3244 Rice Street St. Paul MN, 55126 United States	Electronic Service		No	24-318E002-CI-24-318
22	Nicholas	Haeg	haeg@fresh-energy.org			12298 Bass Trail Sauk Centre MN, 56378 United States	Electronic Service		No	24-318E002-CI-24-318
23	Joe	Halso	joe.halso@sierraclub.org	Sierra Club		1536 Wynkoop St Ste 200 Denver CO, 80202 United States	Electronic Service		No	24-318E002-CI-24-318
24	Kim	Havey	kim.havey@minneapolismn.gov	City of Minneapolis		350 South 5th Street, Suite 315M Minneapolis MN, 55415 United States	Electronic Service		No	24-318E002-CI-24-318
25	Amber	Hedlund	amber.r.hedlund@xcelenergy.com	Northern States Power Company dba Xcel Energy-Elec		414 Nicollet Mall, 401-7 Minneapolis MN, 55401 United States	Electronic Service		No	24-318E002-CI-24-318
26	Adam	Heinen	aheinen@dakotaelectric.com	Dakota Electric Association		4300 220th St W Farmington	Electronic Service		No	24-318E002-CI-24-318

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
						MN, 55024 United States				
27	Mari	Hernandez	mari@irecusa.org	IREC		null null, null United States	Electronic Service		No	24-318E002-CI-24-318
28	Katherine	Hinderlie	katherine.hinderlie@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	445 Minnesota St Suite 1400 St. Paul MN, 55101-2134 United States	Electronic Service		No	24-318E002-CI-24-318
29	Casey	Horan	choran@edf.org	Environmental Defense Fund		123 Mission St San Francisco CA, 94105 United States	Electronic Service		No	24-318E002-CI-24-318
30	Samantha	Houston	shouston@ucsusa.org	Union of Concerned Scientists		1825 K St. NW Ste 800 Washington DC, 20006 United States	Electronic Service		No	24-318E002-CI-24-318
31	Philip	Jones	phil@evtransportationalliance.org			1402 Third Ave Ste 1315 Seattle WA, 98101 United States	Electronic Service		No	24-318E002-CI-24-318
32	William	Kenworthy	will@votesolar.org			1 South Dearborn St Ste 2000 Chicago IL, 60603 United States	Electronic Service		No	24-318E002-CI-24-318
33	Bobby	King	bking@solarunitedneighbors.org	Solar United Neighbors		3140 43rd Ave S Minneapolis MN, 55406 United States	Electronic Service		No	24-318E002-CI-24-318
34	Nathan	Kostiuk	nathan.c.kostiuk@xcelenergy.com	Xcel Energy		414 Nicollet Mall, 401-07 Minneapolis MN, 55401 United States	Electronic Service		No	24-318E002-CI-24-318
35	Becky	Li	bli@rmi.org			17 State St 25th floor unit 2500 New York NY, 10004 United States	Electronic Service		No	24-318E002-CI-24-318
36	Jody	Londo	jody.l.londo@xcelenergy.com	Xcel Energy		414 Nicillet Mall 7th Floor Minneapolis MN, 55401-1993 United States	Electronic Service		No	24-318E002-CI-24-318
37	Madeline	Lydon	madeline.k.lydon@xcelenergy.com	Xcel Energy		401 NICOLLET MALL Floor 7 Minneapolis MN, 55401 United States	Electronic Service		No	24-318E002-CI-24-318
38	Tom	Mammen	thomas.j.mammen@xcelenergy.com	Xcel Energy		null null, null United States	Electronic Service		No	24-318E002-CI-24-318
39	Gregg	Mast	gmast@cleanenergyeconomymn.org	Clean Energy Economy Minnesota		4808 10th Avenue S Minneapolis MN, 55417 United States	Electronic Service		No	24-318E002-CI-24-318

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
40	Erica	McConnell	emcconnell@elpc.org	Environmental Law & Policy Center		35 E. Wacker Drive, Suite 1600 Chicago IL, 60601 United States	Electronic Service		No	24-318E002-CI-24-318
41	Matthew	Melewski	matthew@theboutiquefirm.com	Nokomis Energy LLC & Ole Solar LLC		2639 Nicollet Ave Ste 200 Minneapolis MN, 55408 United States	Electronic Service		No	24-318E002-CI-24-318
42	Brian	Monson	brian.t.monson@xcelenergy.com	Xcel Energy		null null, null United States	Electronic Service		No	24-318E002-CI-24-318
43	Susan	Mudd	smudd@elpc.org	Environmental Law and Policy Center		35 E. Wacker Drive, Suite 1600 Chicago IL, 60601 United States	Electronic Service		No	24-318E002-CI-24-318
44	Pouya	Najmaie	najm0001@gmail.com	Cooperative Energy Futures		3416 16th Ave S Minneapolis MN, 55407 United States	Electronic Service		No	24-318E002-CI-24-318
45	Alex	Nelson	anelson@dakotaelectric.com	Dakota Electric Association		4300 220nd St Farmington MN, 55024 United States	Electronic Service		No	24-318E002-CI-24-318
46	Logan	O'Grady	logrady@mnseia.org	Minnesota Solar Energy Industries Association		2288 University Ave W St. Paul MN, 55114 United States	Electronic Service		No	24-318E002-CI-24-318
47	Ryan	Pierce	ryan.m.pierce@xcelenergy.com	Xcel Energy		null null, null United States	Electronic Service		No	24-318E002-CI-24-318
48	Matt	Privratsky	matt@nokomisenergy.com	Nokomis Energy		2639 Nicollet Ave Suite 200 Minneapolis MN, 55408 United States	Electronic Service		No	24-318E002-CI-24-318
49	Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	1400 BRM Tower 445 Minnesota St St. Paul MN, 55101-2131 United States	Electronic Service		Yes	24-318E002-CI-24-318
50	Kwadwo	Safo	ksafo@dakotaelectric.com	Dakota Electric Association		null null, null United States	Electronic Service		No	24-318E002-CI-24-318
51	Dean	Schiro	dean.e.schiro@xcelenergy.com	Xcel Energy		null null, null United States	Electronic Service		No	24-318E002-CI-24-318
52	Peter	Scholtz	peter.scholtz@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	Suite 1400 445 Minnesota Street St. Paul MN, 55101-2131 United States	Electronic Service		No	24-318E002-CI-24-318
53	Paul	Schroeder	pauls@hourcar.org	HOURCAR		755 Prior Ave. N Suite 301D Saint Paul	Electronic Service		No	24-318E002-CI-24-318

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
						MN, 55104 United States				
54	Christine	Schwartz	regulatory.records@xcelenergy.com	Xcel Energy		414 Nicollet Mall, MN1180-07-MCA Minneapolis MN, 55401-1993 United States	Electronic Service		No	24-318E002-CI-24-318
55	Emma	Searson	esearson@solarunitedneighbors.org	Solar United Neighbors		646 S Barrington Ave Apt 101 Los Angeles CA, 90049 United States	Electronic Service		No	24-318E002-CI-24-318
56	Will	Seuffert	will.seuffert@state.mn.us		Public Utilities Commission	121 7th Pl E Ste 350 Saint Paul MN, 55101 United States	Electronic Service		Yes	24-318E002-CI-24-318
57	Lindsey	Stegall	lindsey.stegall@evgo.com	EVgo Services, LLC		11835 W Olympic Blvd Ste 900E Los Angeles CA, 90064 United States	Electronic Service		No	24-318E002-CI-24-318
58	Chad	Stevenson	chad.stevenson@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	445 Minnesota St. Suite 1400 St. Paul MN, 55101 United States	Electronic Service		No	24-318E002-CI-24-318
59	Tammy	Sundbom	tsundbom@mnpower.com	Minnesota Power		null null, null United States	Electronic Service		No	24-318E002-CI-24-318
60	Boratha	Tan	btan@votesolar.org	Vote Solar		null null, null United States	Electronic Service		No	24-318E002-CI-24-318
61	Dean	Taylor	dtaylor@pluginamerica.org	Plug In America		6380 Wilshire Blvd, Suite 1000 Los Angeles CA, 90048 United States	Electronic Service		No	24-318E002-CI-24-318
62	Daniel	Tikk	daniel.tikk@state.mn.us		Department of Commerce	85 7th Place East Suite 280 Saint Paul MN, 55101 United States	Electronic Service		No	24-318E002-CI-24-318
63	Kate	Tohme	ktohme@newleafenergy.com	New Leaf Energy		null null, null United States	Electronic Service		No	24-318E002-CI-24-318
64	Taige	Tople	taige.d.tople@xcelenergy.com	Northern States Power Company dba Xcel Energy-Elec		414 Nicollet Mall 401 7th Floor Minneapolis MN, 55401 United States	Electronic Service		No	24-318E002-CI-24-318
65	Matt	Van Arkel	mvanarkel@newleafenergy.com			55 Technology Drive Suite 102 Lowell MA, 01851 United States	Electronic Service		No	24-318E002-CI-24-318
66	Curt	Volkmann	curt@newenergy-advisors.com	Fresh Energy		408 St Peter St Saint Paul MN, 55102 United States	Electronic Service		No	24-318E002-CI-24-318

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
67	Sarah	Whebbe	swhebbe@mnseia.org	MnSEIA		445 Minnesota Street Suite 730 St. Paul MN, 55101 United States	Electronic Service		No	24-318E002-CI-24-318
68	Joshua	Williams	joshua@highlandfleets.com	Highland Electric Fleets		200 Cummings Center Suite 273-D Beverly MA, 01915 United States	Electronic Service		No	24-318E002-CI-24-318
69	Laurie	Williams	laurie.williams@sierraclub.org	Sierra Club		Environmental Law Program 1536 Wynkoop St Ste 200 Denver CO, 80202 United States	Electronic Service		No	24-318E002-CI-24-318
70	Anthony	Willingham	anthony.willingham@electrifyamerica.com	Electrify America		1950 Opportunity Way Suite 1500 Reston VA, 20190 United States	Electronic Service		No	24-318E002-CI-24-318
71	Ari	Zwick	ari.zwick@state.mn.us		Department of Commerce	85 7th Place East Suite 280 Saint Paul MN, 55101 United States	Electronic Service		No	24-318E002-CI-24-318