414 Nicollet Mall
Minneapolis, MN 55401

November 19, 2025

—Via Electronic Filing—

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

RE: REPLY COMMENTS
DISTRIBUTION COST SHARING FOR INTERCONNECTION
DOCKET NO. E002,E015,E017/CI-24-288

Dear Ms. Bergman:

Northern States Power Company, doing business as Xcel Energy, submits the enclosed Reply Comments in response to the September 26, 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 list. Please contact Nathan Kostiuk at nathan.c.kostiuk@xcelenergy.com or contact me at brian.t.monson@xcelenergy.com if you have any questions regarding this filing.

Sincerely,

/s/

BRIAN MONSON
MANAGER, REGULATORY AFFAIRS

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 ESTABLISHING TARIFFS FOR DISTRIBUTION SYSTEM COST SHARING FOR INTERCONNECTION IN CONSTRAINED AREAS	DOCKET NO. E002,E015,E017/CI-24-288 **REPLY COMMENTS**

INTRODUCTION

Northern States Power Company, doing business as Xcel Energy, submits these Reply Comments in response to comments submitted by several parties on November 7, 2025, consistent with the Commission's September 26, 2025 Notice of Comment Period in the above-referenced docket. The Notice follows the conclusion of a Commission-led workgroup process. The Distributed Energy Resources (DER) Cost Sharing Workgroup met over a series of meetings to develop draft generic standards for the Distribution System Reactive Upgrade Process (DSRUP). The process results from Minnesota Session Laws – 2024, Regular Session, Chapter 126, Article 6, Section 53 (DSRUP law).[1] The law requires the Commission to establish generic standards:

> *for the sharing of utility costs necessary to upgrade a utility's distribution system by increasing hosting capacity or applying other necessary distribution system upgrades at a congested or constrained location in order to allow for the interconnection of distributed generation facilities.*

The Comments indicate that the efforts of the DER Cost Sharing Workgroup have led to many areas of consensus within the draft generic Standards. We appreciate the work and Comments from the Department of Commerce, Office of the Attorney General (OAG), Joint Solar Commenters/Cooperative Energy Futures (JSC/CEF), Minnesota Solar Energy Industries Association (MnSEIA), Otter Tail Power, and Minnesota Power.

[1] Available at https://www.revisor.mn.gov/laws/2024/0/126/laws.6.53.0#laws.6.53.0.

In these Reply Comments, we focus on our priority areas of the Standards where our positions differ from parties. Our goal is to support DSRUP generic Standards that protect non-participating customers, enable timely and fulsome recovery of all costs in a way that aligns with established cost allocation and recovery principles, and ensure process efficiency for smooth and streamlined implementation.

We also emphasize that while the generic Standards should aim to be clear yet flexible enough that frequent modifications are not necessary, DSRUP is a new program, and it is likely that all parties will learn from early implementation and discover areas of the generic Standards that work well or could be improved. The Commission and parties can and should take stock of how DSRUP is working in its early stages and make adjustments as needed. Therefore, we request the Commission to adopt clear yet flexible generic Standards with the understanding that the process will likely benefit from iterative improvements over time.

The following attachments are provided with this filing:

Attachment 1: Xcel Energy's Updated Preferred DSRUP Standards
Attachment 2: Xcel Energy's Preferred DSRUP Dispute Resolution Process
Attachment 3: Xcel Energy's Updated, Expanded Position Matrix for DSRUP

Attachment 3 provides an expanded version of the matrix provided with our Initial Comments. In Attachment 3, we address each proposed Requirement, including any modifications or new Requirements proposed by parties in Initial Comments. Attachment 3 also denotes the Requirements that we understand to be consensus items unopposed by any party. We largely maintain the positions provided in our Initial Comments, but note where we offer additional minor modifications or support others' modifications. Attachments 1 and 2 provide an updated version of our preferred generic Standards and Dispute Resolution Process, respectively.

We respectfully request that the Commission:

- Adopt the Company's updated preferred DSRUP generic Standards and preferred DSRUP Dispute Resolution Process in Attachments 1 and 2 to these Reply Comments, respectively.
- Set a procedural schedule for the filing of proposed tariffs such that a Commission hearing to set the terms of the tariffs can be scheduled no sooner than the third quarter of 2026.

REPLY COMMENTS

I. A CLEAR PATH TO COST RECOVERY IS ESSENTIAL FOR THIS MANDATORY, MARKET-DRIVEN PROGRAM

The Company has a long history of supporting and contributing to Minnesota's clean energy goals; DSRUP is no different. We are pleased to have the opportunity to help shape this program in support of Minnesota policy and our interconnection customers. That said, DSRUP is a mandatory, market-driven program over which the Company has, by design, limited control. As such, we agree with the JSC/CEF that "there needs to be some amount of assurance that the utility will be able to recover the cost of" Upgrades.[2] Without such assurance, JSC/CEF notes the utility could be hesitant and cautious "and it would defeat the ultimate purpose of the DSRUP: to relieve grid congestion and get more distributed generation on the grid in order to offset increasing load and achieve Minnesota's stated climate goals."[3]

A. A Rebuttable Presumption of Prudence Is Imperative

JSC/CEF's reasoning supports adoption of Requirement G.5, which would provide a rebuttable presumption of prudence. We strongly support Requirement G.5 for the reasons JSC/CEF noted, as we explain further below.

G.5 is imperative for the Company. DSRUP is a mandatory, market-driven program under which neither the Commission nor the Company will directly control or approve the Upgrades that move forward; rather, the generic Standards must provide a robust prioritization and selection framework under which Upgrades are constructed. Use of this prioritization process in Requirement G.1 and the Standards overall should create a rebuttal presumption of prudence in future cost recovery proceedings. The OAG asserts that as written, under Requirement G.5 the utility would not be required to provide any information about upgrades when seeking cost recovery.[4] We respectfully disagree. As JSC/CEF notes, parties must have sufficient information in a cost recovery proceeding to be able to rebut the presumption of prudence if needed.[5] In any cost recovery proceeding, the Company provides robust accounting; further, the Company supports the regular, detailed data publication and reporting in Requirements M.1 and Section N. The OAG offers a modified version of Requirement G.5, but we continue to support the original language that references a rebuttable presumption of prudence:

[2] JSC/CEF Comments at p. 8.
[3] *Id.*
[4] OAG Comments at p. 16.
[5] JSC/CEF Comments at p. 8.

G.5 Approval through the prioritization process chosen in Section G shall create a rebuttable presumption of prudence in any cost recovery proceeding.

That said, OAG's modified G.5 includes an important and reasonable edit to change the first word – "Approval" – to "Selection." As we explain here and in our Initial Comments, neither the Company nor the Commission will "approve" the Upgrades, so "selection" is a more accurate reflection of how the prioritization process functions. As such, we offer a modification of Requirement G.5:

Xcel G.5 ~~Approval~~ Selection through the prioritization process chosen in Section G shall create a rebuttable presumption of prudence in any cost recovery proceeding.

We also note that Requirement G.5 is consistent with the Proactive Distribution Upgrades Framework.[6]

B. Timely and Fulsome Cost Recovery is the Law

Some commenters support Requirements that would effectively punish the Company for implementing this mandatory, market-driven program in good faith. Specifically, Requirements K.1, K.2, K.3.b would harm the Company and should be rejected.

The Department supports Requirement K.1 that would prohibit the Company from recovering its costs for five years after a project reaches its Mobilization Threshold. This requirement would be punitive and not consistent with Minnesota law, which allows the Company "to recover on a timely basis the costs of upgrades that are not allocated to participating distributed generation facilities under the commission order issued in" this docket.[7] In the past, deferred recovery has been used to mitigate large impacts or rate shocks on customers. To be sure, mitigating rate impacts is a priority for the Company, and our preferred Standards accomplish that in a way that is consistent with the law.

Requirement K.2 would further punish the Company during the five-year waiting period by not allowing accrual of carrying costs. The Company's understanding is that no parties support Requirement K.2 as a first choice. The Department supports

[6] Docket No. E002/CI-24-318, ORDER ESTABLISHING FRAMEWORK FOR PROACTIVE DISTRIBUTION GRID UPGRADES (September 2, 2025), Requirement I.7: "The Commission's Proactive Distribution Upgrade Proposal decision creates a rebuttable presumption, in a cost-recovery proceeding, that upgrades completed consistent with the decision are prudent."
[7] Minn. Stat. 216B.16, subd. 7b(b)(6).

Requirement K.3.b,[8] which would allow carrying costs during the five-year waiting period calculated using the utility's long-term cost of debt, instead of the authorized weighted average cost of capital (WACC) in Requirement K.3.a. DSRUP capital projects proposed within this framework are comparable to other utility investments, and therefore, the capital allocated by the Company for these projects will be financed under the same financing costs as its broader capital portfolio. Under Requirement K.3.b, not only would the Company be unable to recover net project costs in a timely manner, but it would also face the additional challenge of receiving carrying costs at a rate below its standard financing rate (WACC). K.1 and K.3.b are misaligned with the law, Commission precedent, and the regulatory compact and should not be adopted.

Requirements D.3 and D.4 would also be unnecessarily punitive and counter to the DSRUP law, which allows recovery of utility's *total* cost of upgrades. Requirements D.3 and D.4 would disallow recovery of costs above 125 percent of the indicative estimated cost of an Upgrade. The Department suggests that this would incentivize the Company to ensure that cost estimates are accurate; on the contrary, this requirement would have the opposite effect, requiring the Company to ensure that additional, sufficiently conservative contingencies are in place to cover any manner of unforeseen circumstances that could conceivably increase costs. As the past five-plus years have demonstrated, many factors outside the Company's control can impact actual costs compared to an early indicative estimate, and the Company – as JSC/CEF noted – needs assurance that we will be able to fully recover the cost of a market-driven Upgrade. Requirements D.3 and D.4 should not be adopted.

The Commission can achieve robust ratepayer protections by adopting a higher Mobilization Threshold alongside a balanced Annual Ratepayer Cost Cap and Upgrade Cost Threshold, as we discuss further below. These Requirements are the appropriate and lawful levers to protect customers, not the punitive policies in Requirements K.1, K.2, K.3.b, D.3, and D.4.

Requirements K.5.a, K.5.b, and K.6.a are straightforward and enable timely and fulsome recovery consistent with the law, and should be adopted.

C. Contributions Should be Returned to Customers as an Offset to Revenue Requirements

Requirement K.6 offers two options for the mechanism by which Reactive Cost Share Contributions from Participants would be returned to ratepayers:

[8] OAG and JSC/CEF also support K.3.b if K.1 is adopted.

K.6. All Reactive Cost Share Contributions collected from Reactive Cost Share Participants shall be collected during the Payback Period and shall be:

a. Returned to ratepayers as an offset to the revenue requirements of Reactive Cost Share Distribution Upgrade.
   OR
b. Used to offset the rate base amount of the Upgrade until the upgraded assets are fully paid down, or the Payback Window closes.

The Department, OAG, and JSC/CEF support K.6.b.

The Department and OAG state that K.6.b is consistent with how Contributions In Aid of Construction (CIAC) are treated. The Company acknowledges that this market-driven reactive framework is more closely aligned with current CIAC procedures it currently uses for its load customers. However, given the pent up demand for DG interconnection and associated upgrades on the Company's system, significant, immediate capital is likely to be required to facilitate those Upgrades. To impair the Company's ability to earn on those investments may pose hardship and financial risk because the Company would be required to raise capital through normal business processes to fulfill the upfront obligations of serving this program, without the ability to earn a fair and reasonable return on these capital investments. As such, K.6.a is more appropriate in recognition of the scale of the program.

OAG goes further and asserts that K.6.a would amount to double-recovery, analogizing that K.6.a is "like allowing a bank to continue charging interest on a loan that was already paid off."[9] This analogy is misplaced and the Company rejects the assertion that returning Reactive Cost Share Contributions to customers as a offset to revenue requirements would result in double recovery. The Company would flow back all Reactive Cost Share Contributions as a credit to ratepayers through its TCR Rider. Using the OAG's analogy, the principal balance of the loan would be returned to rate paying customers, leaving only the interest *balance* which would be recovered over the life of the asset – which is not double recovery. We continue to support K.6.a.

The Commission can achieve robust ratepayer protections through other Standards, as we explain below.

[9] OAG Comments at pp. 24-25.

II. OUR PREFERRED STANDARDS PROTECT CUSTOMERS

As discussed in our Initial Comments, the Mobilization Threshold, Annual Ratepayer Cost Cap, and Upgrade Cost Thresholds are the most consequential requirements to consider in pursuit of customer protection. We support a Mobilization Threshold of 80 percent, an Annual Ratepayer Cost Cap set in a subsequent tariff filing, and an Upgrade Cost Threshold of $2.5 million – Requirements F.1.b, J.1, and C.1.c, respectively. The Payback Period duration is also an important consideration for customer protection, as we explain below. We support a Payback Period duration no longer than 10 years – Requirement I.1.d.

Most commenters recognize that an 80 percent Mobilization Threshold is an important way to reduce the risk of stranded assets and protect non-participating customers.[10] Setting the Annual Ratepayer Cost Cap in a future tariff filing is appropriate and supported by most parties.[11] As discussed in our Initial Comments and explained by other commenters, the Annual Ratepayer Cost Cap and the Mobilization Threshold together create an "operational budget" for Upgrades. This "operational budget" should be manageable for the utility and accomplish the policy goal of deploying more DG. We strongly support an 80 percent Mobilization Threshold in Requirement F.1.b, and setting the Annual Ratepayer Cost Cap in utility-specific tariff filings after the generic Standards are adopted (Requirement J.1).

In the remainder of this section, we focus on the Upgrade Cost Threshold and explain why a higher Upgrade Cost Threshold better aligns with the goal of DSRUP and protects customers. We also discuss the Payback Period duration as another important customer protection and its importance in enabling the smooth function of DSRUP.

JSC/CEF supports a minimum Upgrade Cost Threshold of $1. As explained by the OAG, this is effectively no threshold. OAG further explains:

> *If even the cheapest upgrades are eligible, a developer who would have simply paid for the upgrade themselves under the status quo could choose instead to reduce their costs by pursuing DSRUP. This is possible because if the upgrade cost is low enough, it is easier for a developer to simply meet the Mobilization Threshold by itself. The result would be a price discount equal to: (1 minus the Mobilization Threshold percentage).* [12]

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[10] The Department, OAG, Otter Tail Power, and the Company support a Mobilization Threshold of 80 percent (Requirement F.1.b).

[11] The Department, OAG, Minnesota Power, and the Company support or prefer setting the Annual Ratepayer Cost Cap in a tariff filing upon approval of the utility's DSRUP (Requirement J.1).

[12] OAG Comments at p. 9.

OAG's logic applies to Upgrade Cost Thresholds of $100,000 and $250,000 as well,[13] because the developer community has covered such costs in the past (for Legacy community solar garden [CSG] projects up to 1 MW), demonstrating that cost sharing and subsidies are not required for all projects. This threshold at which cost sharing and subsidies are required is amplified for low- and moderate-income (LMI) Accessible CSG projects, which can be up to 5 MW, or five times larger than Legacy CSG projects. A higher Upgrade Cost Threshold – such as the Company's preferred $2.5 million in Requirement C.1.c – is an important customer protection because it helps ensure the DSRUP is used to clear the largest roadblocks to interconnection by enabling system upgrades that would not otherwise be feasible, and it ensures that the most beneficial Upgrades move forward within the Annual Ratepayer Cost Cap. Also, a lower Upgrade Cost Threshold would lead to the Annual Ratepayer Cost Cap being met more quickly, and more projects that really need DSRUP cost sharing would not be able to move forward unless 100 percent of Upgrade costs were covered by Reactive Cost Share Participants.

The Payback Period is another form of customer protection. The Payback Period is the period, after the Mobilization Threshold is reached, during which the value of the Upgrade can be paid by Reactive Cost Share Participants. In other words, the Payback Period is the time in which other Interconnection Applicants can seek to use an Upgrade and contribute to the remaining (1 – Mobilization Threshold) percent of Upgrade costs.

Commenters support a minimum duration for the Payback Period. We understand why Commenters may think a required minimum duration for the Payback Period is appropriate – to ensure sufficient time for follow-on projects to participate and cover the remaining Upgrade costs and seek to ensure ratepayers are made whole, to the extent possible. That said, a maximum Payback Period is more appropriate for four reasons.

First, a minimum Payback Period alone does not allow for a situation in which the remaining Hosting Capacity created by an Upgrade is *never* used or paid for by a Reactive Cost Share Participant.

[13] Requirements C.1.d and C.1.a, respectively.

Requirement I.2 addresses how the Payback Period ends:

I.2 The Payback Period shall end if:

Xcel I.2.a The Hosting Capacity created by the Upgrade is fully utilized by Reactive Cost Share Participants and all over-payers have been fully refunded the amounts above their Reactive Cost Share Contribution~~.~~, or

b. The duration of the Payback Period defined in I.1 has elapsed.

As shown above, our modification to I.2.a clarifies that both parts of Requirement I.2 are necessary. I.2.a closes the Payback Period when the Upgrade is fully paid for and utilized by Reactive Cost Share Participants. If the Hosting Capacity created by the Upgrade is fully utilized and the costs have been fully covered by Reactive Cost Share Participants, there is no reason to keep the Payback Period open, making a required minimum duration for the Payback Period moot. However, if such a scenario never happens, there must be a maximum Payback Period duration, as contemplated in I.2.b.

The OAG supports only I.2.b. JSC/CEF and the Department support both parts of I.2, with the Department noting that both parts are necessary. However, no parties support a maximum Payback Period duration in I.1 that would elapse and trigger the close of the Payback Period in Requirement I.2.b. In practice, setting *only* a minimum Payback Period duration (as in Requirements I.1.a or I.1.b) is the same as keeping the Payback Period open until 100 percent of Upgrade costs are recovered from Interconnection Customers, as in Requirement I.1.c. Yet no parties indicated that they support Requirement I.1.c.

In order for DSRUP and the generic Standards to function logically, there must be a maximum duration for the Payback Period. A minimum duration for the Payback Period is unnecessary particularly if both parts of Requirement I.2. are adopted.

The second reason a maximum Payback Period duration is needed is to enable the function of the Annual Ratepayer Cost Cap. Under Requirement J.4. – which no parties oppose – after the Payback Period closes, costs of Upgrades that have not been paid by Reactive Cost Share Participants will no longer count toward the Annual Ratepayer Cost Cap. Without a maximum Payback Period duration, as noted above, in practice the Payback Period remains open until 100 percent of the Upgrade costs are paid by Reactive Cost Share Participants. In that case, the Annual Ratepayer Cost Cap could eventually be "filled" by Outstanding Costs from years- or decades-old

Upgrades. A maximum Payback Period duration is needed to open up space for new Upgrades in the Annual Ratepayer Cost Cap.

Thirdly, a maximum Payback Period duration is more appropriate because the distribution system is dynamic. Keeping the Payback Period open potentially indefinitely by only setting a minimum duration would create a situation where the distribution system has changed (e.g., new load, different load shapes, feeder and substation reconfigurations, other projects, etc.) such that the Upgrade may no longer be benefiting or needed for future projects.

Finally, long Payback Periods would create administrative burden and be impracticable to implement and maintain long term. Without a maximum duration, we would need to track and segment our system based on whether the Upgrade was initiated by DSRUP or by traditional distribution planning. We would need two sets of accounting books for our distribution system. While managing this process for up to 10 years is possible, this process would become particularly onerous after 10 years as the program grows and the administrative burden compounds. We support Requirement I.1.d – which would keep the Payback Period open for no more than 10 years from the Upgrade's in-service date – and both parts of Requirement I.2 including our modified I.2.a. Together these Requirements effectively protect customers and reflect practical realities of the distribution system and implementation of DSRUP.

Taken together, an 80 percent Mobilization Threshold, an Upgrade Cost Threshold of $2.5 million, an Annual Ratepayer Cost Cap that is flexible and set in future tariff filings – along with a balanced approach to the Payback Period – are effective customer protections.

III. OTHER ISSUES

MnSEIA and JSC/CEF raise two additional issues: the Company's proposed capacity reservation for small DG, and recommendations regarding costs, cost estimates, and acceptable payments. We briefly address these items below and believe that the Commission can adopt DSRUP requirements that reference the capacity reservation while that topic is being addressed in a separate proceeding. The Commission should not adopt JSC/CEF's recommended additional requirements for the reasons we discuss below.

A. Small DER Capacity Reservation

We appreciate MnSEIA's support of our proposed capacity reservation concept for small DG less than 40 kWac. As directed by the Commission, the framework and details regarding a potential capacity reservation are being addressed through Phase 2 of the Proactive Distribution Grid Upgrades (PDGU) workgroup,[14] but as explained in our Initial Comments, the concept of a capacity reservation has broader implications for proactive upgrades, reactive cost sharing, and queue processing. Requirements E.8.d and H.11 specifically reference the capacity reservation. The Commission can adopt these requirements as written without prejudging the outcome of Phase 2 of the proactive grid upgrades workgroup.[15]

B. Other JSC/CEF Recommendations

JSC/CEF makes four additional recommendations regarding costs and cost estimates; reconciliation statements, and allowable funding mechanisms for interconnection deposits. As an initial matter, these suggestions are broadly applicable to the interconnection process and should be considered within the broader context of MN DIP. The Commission should not adopt them, and should particularly not adopt them in this docket, which does not include all utilities and parties subject to MN DIP. Indeed, these issues have been considered at various points and in various dockets, including MN DIP, and the Commission has declined to impose similar requirements, as we discuss below.

In their Comments in this docket, JSC/CEF suggests that utilities be required "to provide itemized, equipment-level cost breakdowns (including labor, materials, and allowable contingency) in their cost estimates for distribution upgrades.[16] Relatedly, they suggest directing Minnesota's utilities to publish and update matrices with itemized actual costs for common distribution upgrades and to provide interconnection customers with a detailed, itemized, clear statement of final costs for all distribution upgrades, including explanations for variances exceeding 125 percent of the original estimate.[17]

Providing or publishing this detail would violate our contractual obligations with

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[14] Docket No. E002/CI-24-318. See ORDER ESTABLISHING FRAMEWORK FOR PROACTIVE DISTRIBUTION GRID UPGRADES (September 2, 2025), Order Point Nos. 4 and 5.

[15] JSC/CEF suggests a modification to E.8.d to strike the reference to a capacity reservation. In practice, we believe this modified requirement would have the same effect as the original E.8.d, so we do not oppose it, but we continue to prefer and support the original E.8.d.

[16] JSC/CEF Comments at p. 15.

[17] *Id.*

vendors – which also provide equipment enterprise-wide, not solely for DER interconnection projects – which is nonpublic data and would ultimately harm the Company's ability to maintain prices. Further, existing systems and tools do not track this level of detail, as many of the invoices received from vendors lump various activities together. We provide several details to interconnection customers, including technical rationale and costs for applications that require a supplemental review as well as a Scope of Work for small DER interconnections.

The topic of cost breakdowns and itemization has been raised before. In 2021, the Commission opened up MN DIP and MN DIA for suggested changes. At that time, parties suggested more "detailed itemization" for interconnection projects. At the hearing in January 2022, the Commission did not accept these proposals to change the MN DIP or MN DIA and did not require Xcel Energy to change its practices. Subsequently, in 2022, parties made similar requests in Docket No. E002/M-18-714. The Commission's December 19, 2022 Order in that docket stated that the proposals requesting more detail were "cumulative … and … arguably excessive."[18]

The Company's concerns regarding these recommendations have not changed, and circumstances have not changed such that the Commission should consider these requirements again, whether in this proceeding or elsewhere.

Lastly, JSC/CEF recommends the Commission require acceptance of both letters of credit and bonds for interconnection deposits. This is inconsistent with MN DIP and is also inconsistent with the Company's credit policy as allowed under MN DIP. Bonds provide less certainty to the Company and would increase our costs. For example, the financial institution that has issued the bond can raise defenses to making payment. For example, they might argue that more detailed billing needs to be provided. This could necessitate litigation and associated expense to collect on the bond. This would be vesting with a court, instead of the Commission, the interpretation on how MN DIP should operate. Further, JSC/CEF argues that developers should not incur costs until final billing. But the Company incurs costs to construct an upgrade well ahead of the final billing, and should not need to incur carrying costs from the time the upgrade costs are incurred until the time for payment, as proposed by JSC/CEF, which may be well after our upgrade costs have been incurred. For these reasons, the JSC/CEF recommendation should not be adopted.

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[18] ORDER APPROVING IMPLEMENTATION OF COST SHARING PLAN AS MODIFIED, Docket No. E002/M-18-714 (December 19, 2022) at p. 6.

CONCLUSION

There are many areas of consensus within the draft generic Standards. The Company is pleased to support the DSRUP to advance Minnesota's energy policy goals and meet market needs while protecting non-participating customers. The Commission should adopt generic Standards that protect non-participating customers and provide the Company with a clear path to timely, fulsome recovery of costs for this market-driven program. The Company's preferred standards accomplish these goals while supporting Minnesota energy policy.

We respectfully request that the Commission:

- Adopt the Company's updated preferred DSRUP generic Standards and preferred DSRUP Dispute Resolution Process in Attachments 1 and 2 to these Reply Comments, respectively.
- Set a procedural schedule for the filing of proposed tariffs such that a Commission hearing to set the terms of the tariffs can be scheduled no sooner than the third quarter of 2026.

Dated: November 19, 2025

Northern States Power Company

Attachment 1: Xcel Energy Updated Preferred Standards for the Distribution System Reactive Upgrade Process (DSRUP)

Reactive DER Upgrade Cost Sharing Standards

B. Definitions

Defined terms from the MN DIP have the same meanings here and are capitalized throughout the Standards below. Additionally, the Commission adopts the following definitions for the purposes of this proceeding:

1. Annual Ratepayer Cost Cap: The total rolling annual cost of Upgrades that are not paid for by Reactive Cost Share Participants and that may be recovered from ratepayers under Commission-approved cost recovery methods.

JSC/CEF 2. Distributed Generation Project (Project): An energy generating system connected to the distribution system with a capacity no greater than ten megawatts.

3. Distribution System Reactive Upgrade Process (DSRUP or Process): The process and operation of the "generic standards" envisioned by Section 53 of the 2024 Minnesota Session Laws, Regular Session, Chapter 126, Article 6 and approved by the Minnesota Public Utilities Commission.

4. Distribution System Reactive Upgrade Process Cost Share Agreement (DSRUP Agreement): The agreement between an Interconnection Customer and the Utility providing the Interconnection Customer's intention to participate in an Upgrade and to provide a Reactive Cost Share Contribution for an Upgrade with an open Mobilization Window.

5. Hosting Capacity: The maximum capacity of a utility distribution system to transport electricity at a specific location without compromising the safety or reliability of the distribution system.

6. Interconnection Application: An application that has been submitted to a utility for interconnection under MNDIP.

Modifications proposed by the Company or other parties in Initial Comments are denoted in redline. Additional modifications we propose are denoted in blue redline format.

7. Interconnection Customer: A Distributed Generation Project owner that has submitted an Interconnection Application.

8. Minnesota Distributed Energy Resource Interconnection Agreement (MN DIA): The Agreement intended to provide for the Interconnection Customer to interconnect at the Point of Common Coupling and operate a Distributed Energy Resource with a Nameplate Rating of 10 Megawatts (MW) or less in parallel with the Area EPS at the location identified above and in the Interconnection Application. MN DIP Section 1.1.5 details when the Uniform Statewide Contract may replace the need for the MN DIA.

9. Minnesota Distributed Energy Resource Interconnection Process (MN DIP): The generic, statewide standards for the interconnection and parallel operation of distributed energy resources of no more than 10 MW. All regulated Area Electrical Power System (EPS) Operators are subject to the MN DIP.

10. Mobilization Threshold: The percentage of the estimated total Upgrade cost that must be committed in order for construction of the Upgrade to move forward.

11. Mobilization Window: When the Trigger Project by itself does not meet the Mobilization Threshold, the time period during which additional projects can commit to pay for Upgrade costs and those commitments will count towards the Upgrade's Mobilization Threshold.

12. Outstanding Costs: Any Reactive Cost Share Distribution Upgrade costs that are unrecovered from Reactive Cost Share Participants at any given time, after a Mobilization Threshold has been met and before the Payback Period has been closed.

13. Payback Period: The period of time, after the Mobilization Threshold has been met, allotted for the full value of the Upgrade to be paid for by Reactive Cost Share Participants.

14. Pro Rata Cost: The $/kWac rate calculated by dividing the total costs of the eligible Upgrade by the total kilowatts of Hosting Capacity created by the Upgrade.

15. Reactive Cost Share Contribution: The contribution made by an Interconnection Customer toward an Upgrade. The amount is determined by multiplying the Pro Rata Cost by the kWac capacity of the facility seeking interconnection.

16. Reactive Cost Share Distribution Upgrade (Upgrade): A distribution Upgrade made under the DSRUP. This type of Upgrade must be a modification of a Utility's distribution system at a specific location that is necessary to allow the interconnection of Distributed Generation Projects by increasing Hosting Capacity at the applicable location, including but not limited to installing or modifying equipment at a substation or along a distribution line. Upgrade does not mean an expansion of hosting capacity dedicated solely to the interconnection of a single Distributed Generation Project. Upgrade does not mean construction of a new substation for the sole purpose of allowing the interconnection of Distributed Generation Projects or other upgrades that do not align with MN DIP.

17. Reactive Cost Share Participant: An Interconnection Customer who elects to participate in a Reactive Cost Share Distribution Upgrade with an open cost-share window and is responsible for paying a cost-share contribution.

18. Reactive Upgrade Workgroup: The workgroup created in Docket 24-288 to create the draft standards of the DSRUP.

19. Trigger Project: The initial Interconnection Application for interconnection for a Distributed Generation Project that alerted a Utility that an Upgrade is needed in order to accommodate the Trigger Project and any future interconnections at the applicable location.

20. Utility: A public utility, as defined in Minnesota Statutes, section 216B.02, subdivision 4, that provides electric service.

C. Upgrade Cost Thresholds

1. To qualify for the DSRUP, an Upgrade must have total project costs of at least

   c. $2,500,000.

D. Pro Rata Cost Calculation

1. When a Trigger Project elects to initiate the DSRUP and become a Reactive Cost Share Participant, the Utility shall calculate the estimated Pro Rata Cost defined as the total estimated costs of the eligible Upgrade divided by the total kilowatts of Hosting Capacity created by the Upgrade.

2. The estimated Pro Rata Cost shall be considered an estimate in the calculation of a particular Reactive Cost Share Customer's Reactive Cost Share Contribution until a final Pro Rata Cost is determined after the final bill of actual costs for the Upgrade is issued consistent with MN DIP 5.6.4.1. The Utility shall either refund any excess fees paid or assess each Reactive Cost Share Participant the remaining amount, based on the final Pro Rata Cost of the Upgrade. Refunded amounts shall be issued by the Utility within 30 Business Days after the issuance of the final bill of actual costs. Additional assessments shall be paid by Reactive Cost Share Participants within 30 Business Days after the issuance of the final bill of actual costs. Interconnection Customers that elect to become a Reactive Cost Share Participant following construction of the Upgrade will be assessed a Reactive Cost Share Contribution based on the final Pro Rata Costs.

E. Interconnection Process

1. The DSRUP can only be initiated when a Distributed Energy Project completes a Facilities Study, and the results of the study indicate an eligible Upgrade is required. The Interconnection Customer will be given 20 Business Days after a signature-ready MN DIA and signature-ready DSRUP Agreement

are provided to the Interconnection Customer to choose one of the following options:

a. Participate in the DSRUP and act as a Trigger Project by signing and funding the DSRUP Agreement; or
b. Pay the full cost of the Upgrade as described in Section F2 by signing and funding the DSRUP Agreement; or
c. Withdraw its application

2. An Interconnection Application that triggers an Upgrade shall have the option to pay for the full Upgrade, foregoing the cost sharing process and thus paying in full for the additional capacity beyond their project's need. Should the Interconnection Customer choose to fund the full Upgrade cost and forgo the cost sharing process they shall not be entitled to use excess capacity created by the Upgrade or receive any compensation from future Interconnection Customers utilizing the capacity created by the Upgrade.

3. Interconnection Applications with capacity no greater than 40 kWac and do not have available Hosting Capacity to interconnect shall be informed prior to Initial Review of the likely need ~~offered the opportunity~~ to participate in the DSRUP ~~prior to Initial Review~~. These projects are still subject to the MN DIP process for reviewing, studying, and processing their Interconnection Application.

4. An Interconnection Application with a nameplate rating more than 40 kWac is eligible to participate in an active Mobilization Window:

   b. After all applicable MN DIP studies have been completed.

5. Utilities shall streamline System Impact Studies for Interconnection Applications in queue behind a Trigger Project in Upgrades with an active Mobilization Window to the extent practicable. For Interconnection Applications starting a System Impact Study after a Mobilization Threshold has been met, the Utility shall utilize the Trigger Project's System Impact Study to the extent practicable.

6. Interconnection Agreements for Reactive Cost Share Participants shall not be tendered for signature until after the Mobilization Threshold has been met and any applicable cluster studies have been completed.

7. Utility shall countersign all Interconnection Agreements within 5 business days after receiving all signed Interconnection Agreements from all Reactive Cost Share Participants that are participating in the Upgrade.

8. Interconnection customers that elect to be a Reactive Cost Share Participant shall have their queue status updated to "Awaiting Cost Share Upgrade Selection" until the Interconnection Agreements for all Reactive Cost Share Participants that are participating in the Upgrade have been signed and countersigned by the Utility.

    a. Interconnection Applications in the "Awaiting Cost Share Upgrade Selection" status will maintain their queue position, and the next-in-queue project will be processed and studied through MN DIP. After completion of the System Impact Study and, if necessary, Facilities Study, next-in-queue projects will be notified by the Utility with a signature-ready DSRUP agreement. Next-in-queue projects must sign the DSRUP Agreement and pay the administrative fee within 10 Business Days of receiving notification from the Utility, or withdraw
    b. Next-in-queue projects will not be allowed to pay the entire cost of the upgrade under section E.2.
    c. If the System Impact Study and Facilities Study for a next-in-queue project determines that a new eligible Upgrade is required that does not fit within the scope of the existing Upgrade, then that next-in-queue project may choose to become a Trigger Project for the new upgrade following E.1 of the Standards.
    d. Interconnection Applications that are processed as a next-in-queue project and have a capacity no greater than 40 kWac may proceed with interconnection if no upgrades are required and Hosting Capacity is available for applications with a capacity no greater than 40 kWac through a capacity reservation.

9. After all Interconnection Agreements for all Reactive Cost Share Participants that are participating in an Upgrade are countersigned by the Utility, the Upgrade will proceed to detailed design and construction. Reactive Cost Share Participants will have their queue status updated to "Cost Share Upgrade In Progress." Until the Upgrade has been placed in-service. Interconnection Applications will have the estimated Reactive Cost Share Contribution included as an interconnection upgrade cost in the Interconnection Agreement. The Interconnection Agreement must be signed and timely paid consistent with MN DIP timelines.

10. ~~After an Upgrade has been placed in-service and before~~ Before the Payback Period has closed, the queue will be processed following MN DIP. Interconnection Applications that are Deemed Complete during this time will have the estimated Reactive Cost Share Contribution, or the final Reactive Cost Share Contribution if available, included as an interconnection upgrade cost in the Interconnection Agreement. The Interconnection Agreement must be signed and timely paid consistent with MN DIP timelines.

F. Mobilization Threshold and Window

1. The Mobilization Threshold for an individual Upgrade is set at:

    b. 80 percent of total Upgrade costs.

2. The Mobilization Window for an Upgrade shall remain open until an alteration in the electric distribution system requires a new distribution System Impact Study to confirm the accuracy or necessity of the previously identified Upgrade. When the Mobilization Threshold is met the Utility may conduct a new mandatory cluster study with the costs assigned to the relevant Cost Share Participants consistent with a Utility's Cluster Study guidelines and timelines. Refusal by a Reactive Cost Share Participant to pay for its share of the study cost will constitute withdrawal.

3. If either of the scenarios described in 3a or 3b occurs in the steps following an Upgrade being selected in the Upgrade prioritization process, the Utility will issue notice to the Reactive Cost Share Participants participating in the

Upgrade that the Upgrade will be moved back to an open Mobilization Window. Within 20 Business days from the issuance of the notice by the Utility, the Reactive Cost Share Participants may elect to pay more than their project's Reactive Cost Share Contribution in order to reach the Mobilization Threshold, or the Upgrade will be moved back to an open Mobilization Window. After an Upgrade is moved back to an open Mobilization Window, when the Mobilization Threshold has been met again, the Upgrade will advance to the prioritization selection process.

a. A Reactive Cost Share Participant withdraws such that the mobilization threshold is no longer reached.
b. The final cluster study cost estimate varies from the previous estimate such that the mobilization threshold is no longer reached.

4. If either of the scenarios described in 4a or 4b occurs in the steps following an Upgrade being selected in the Upgrade prioritization process, the Upgrade will be reprioritized against the criteria in G.1 of the Standards. If the reprioritization results in the Upgrade no longer maintaining its priority, it will be reconsidered in the next prioritization process as described in G.4 of the Standards before proceeding.

    a. A Reactive Cost Share Participant withdraws.
    b. The final cluster study cost estimate varies from the previous estimate by more than 20%.

5. If an Upgrade is moved back to an open Mobilization Window after estimated Reactive Cost Share Contributions have been paid by a Reactive Cost Share Participant, the Utility shall issue refunds of the estimated Reactive Cost Share Contributions within 30 Business Days from the date the Utility notifies the Reactive Cost Share Participants that the Mobilization Window is being reopened.

7. The Mobilization Window shall close if the Mobilization Threshold is not reached within two years.

8. The Mobilization Window shall close if all Reactive Cost Share Participants withdraw.

G. Upgrade Prioritization

1. When there are multiple eligible Upgrades that have reached the Mobilization Threshold, their construction shall be prioritized based on the below-listed criteria. In the case different upgrades are tied or equal in a given criterion, the upgrade will be prioritized by the next following criterion. The criteria used to evaluate the upgrades shall adhere to the following order:

    a. The Upgrade with the highest percentage of developer-funded Upgrade cost
    b. Lowest cost per megawatt of capacity added by the Upgrade
    c. Most capacity constraints
    d. Clear optimization benefits for the grid

2. Notwithstanding the criteria listed in G1, where supply chain issues, permitting issues, or other issues that may delay an Upgrade by one year or longer are encountered, the Utility may remove the Upgrade from consideration until the next Upgrade prioritization review, and instead select the next highest priority Upgrade using the prioritization criteria.

3. Following tariffed process initiation, every ____ the Utility shall review Upgrades that have met the Mobilization Threshold during the previous ____ months and prioritize them based on criteria in G1.

    b. Six Months

5. ~~Approval~~ Selection through the prioritization process chosen in Section G shall create a rebuttable presumption of prudence in any cost recovery proceeding.

H. Payment Details

1. Interconnection Customers that have elected to participate in an Upgrade during an open Mobilization Window shall have an executed DSRUP

Agreement to pay their Reactive Cost Share Contribution at the time the Interconnection Agreement is signed and paid consistent with MN DIP timelines.

2. Interconnection Customers shall pay a non-refundable administrative fee with each executed DSRUP Agreement to participate in an Upgrade during an open Mobilization Window. The Interconnection Customer may exit the DSRUP Agreement at any time but will not be refunded the administrative fee.

3. A DSRUP Agreement shall not be contingent upon any other DSRUP Agreement for another Upgrade.

4. Reactive Cost Share Participants may withdraw after all Interconnection Agreements for all Reactive Cost Share Participants that are participating in an Upgrade are countersigned by the Utility but shall not receive a refund of their Reactive Cost Share Contribution.

OAG 8. Any Reactive Cost Share Participant may pay more than their project's Reactive Cost Share Contribution in order to reach the Mobilization Threshold of an Upgrade. This payment beyond their project's calculated Reactive Cost Share Contribution shall be refunded if additional Reactive Cost Share Contributions are received prior to the Payback Period closing. A refund shall be issued to the overpaying Reactive Cost Share Participant within 30 business days from the date a new Reactive Cost Share Contribution is collected by the Utility. The amount refunded to overpaying Reactive Cost Share Participant is determined by the Reactive Cost Share Contribution collected from the new Reactive Cost Share Participant, not exceeding the amount of excess payment remaining to be refunded. Any remaining excess payment is not refundable once the Payback Period closes. Once ~~the Payback Period closes or~~ the over-payer has been fully refunded the excess payment, all funds from subsequent Reactive Cost Share Participants shall be credited to ratepayers.

9. If two or more Reactive Cost Share Participants pay more than their projects' Reactive Cost Share Contribution obligations for a single Upgrade, the Utility

shall refund such excess amounts in the order in which the excess payments were received. The reactive cost Share Participant whose excess payment was received first shall be refunded in full prior to the issuance of any refund to the Participant whose excess payment was received subsequently, and this sequence shall continue accordingly until all excess payments have been refunded.

10. There may be cases where a Utility collects greater than 100% of the final Upgrade costs and over-paying Reactive Cost Share Participants have already been refunded. If this occurs the excess will be returned to ratepayers by reducing the Utility's total recovery of distribution capital costs of the DSRUP the next time it seeks recovery for Process's costs.

11. Interconnection Applications under 40 kWac are exempt from paying a Reactive Cost Share Contribution if Hosting Capacity is available for Interconnection Applications under 40 kWac through a capacity reservation.

12. Reactive Cost Share Participants may use other, Utility-specific, cost sharing programs to fund their Reactive Cost Share Contribution where applicable and with subsequent approval in those relevant Utility-specific cost sharing program docket proceedings.

I. Payback Period

1. The Payback Period shall remain open once the Mobilization Threshold is reached and remains open for:

    d. No more than ten years from the Upgrade's in-service date

2. The Payback Period shall end if:

    a. The Hosting Capacity created by the Upgrade is fully utilized by Reactive Cost Share Participants and all over-payers have been fully refunded the amounts above their Reactive Cost Share Contribution, or~~.~~
    b. The duration of the Payback Period defined in I.1 has elapsed.

3. All Interconnection Applications that are in the Deemed Complete state, as defined in MN DIP, within the Payback Period shall be subject to paying their Reactive Cost Share Contribution, unless otherwise exempted under section H.

J. Annual Ratepayer Cost Cap

1. The Commission shall decide the Annual Ratepayer Cost Cap for Utility in a tariff filing upon approval of that Utility's DSRUP.

3. The Commission intends that the Annual Ratepayer Cost Cap will remain in place for at least 24 months since the most recent change to the cost cap went into effect before the Commission considers modifications. A Utility, prospective Trigger Projects, and ratepayer advocates may request a modification to the Annual Ratepayer Cost Cap. In determining whether to change the Annual Ratepayer Cost Cap, the Commission shall consider, at a minimum, previous and future ratepayer costs and risks arising from the Utility's DSRUP, total pending cost share contributions, and the demand for new Upgrades.

4. The Outstanding Costs of constructed Upgrades that have not been paid for by Reactive Cost Share Contributions shall count towards the Annual Ratepayer Cost Cap.

    a. Costs of Upgrades that have not been paid for by Reactive Cost Share Participants upon the Payback Period closing shall be removed from the Annual Ratepayer Cost Cap.

5. Once the Annual Ratepayer Cost Cap is reached, the Mobilization Threshold for all pending Upgrades is set to 100 percent until the total amount recoverable from ratepayers drops below the cap. ~~As available space opens up within the cost cap, projects transitioning back to the standard Mobilization Threshold shall follow existing prioritization processes.~~

K. Cost Recovery

5. A Utility may petition to recover outstanding costs through any or all of the following (but without any double recovery):

    a. Through a general rate case.
    b. Through its Transmission Cost Recovery Rider pursuant to Minn. Stat. 216B.16, Subd. 7b, paragraph (b), clause 6.

6. All Reactive Cost Share Contributions collected from Reactive Cost Share Participants shall be collected during the Payback Period and shall be:

    a. Returned to ratepayers as an offset to the revenue requirements of Reactive Cost Share Distribution Upgrade.

L. Cost Allocation

1. Costs recovered from ratepayers shall be treated consistent with the most recently approved rate case allocators and established revenue requirement procedures. Parties to a Utility's rate case or other cost recovery proceeding may request that the Commission establish a different cost allocation and procedures for DSRUP Upgrades.

M. Publication of DSRUP Information and Data

1. Utilities shall make all reasonable efforts to publish the feeders and/or substations that have an open Mobilization Window and the availability of potential Upgrades where there is an open Mobilization Window as well as where there is an Upgrade already constructed that still has available hosting capacity remaining. Utilities shall publish the following information on a monthly basis for each active Upgrade location:

    a. The $/kW Pro Rata Cost to participate in the Upgrade[1]
    b. Start and end dates of the Mobilization Window
    c. Start and end dates of the Payback Period
    d. The feeders and/or substations that have an open Mobilization Window

[1] This does not include any upgrades in addition to the DSRUP Upgrade an individual DER project may require

e. The maximum amount of distribution capacity that could be created by the Upgrade
f. Status of the Mobilization Threshold
    i. How many projects have opted in
    ii. The capacity they have taken up
    iii. The progress, in percentage, towards the Mobilization Threshold

3. The information in M1 shall be listed on a spreadsheet.

N. Reporting and Process Evaluation

1. Utilities shall file an annual compliance filing in Docket 24-288 the following reporting requirements:

    a. List of ongoing projects by feeder and status (waiting for Mobilization Threshold to be reached, Upgrades in progress, post-construction Mobilization Window)
    b. Status of the Annual Ratepayer Cost Cap (how much $ space is available)
    c. Revenue requirements
    d. Impact to the Annual Ratepayer Cost Cap from each project including a forecast of cap space (assuming no new cost share customers interconnect)
    e. Total costs allocated to ratepayers by the DSRUP
    f. Total capacity (kWac) added by the DSRUP
    g. Total cumulative capacity (kWac) added by DSRUP
    h. Total amount funded by Reactive Cost Share Contributions
    i. Details about each individual Upgrade made, including
        i. Capacity added
        ii. Total Cost (estimated, final), Pro Rata Cost (estimated, final)
        iii. Trigger date, construction date, etc. (length to Mobilization Threshold)
        iv. How many projects were involved, their sizes
    j. The monetary benefit to ratepayers as a result of Upgrades that were more than 100% funded.
    k. The results of upgrade prioritization process for each Upgrade.

2. Utilities must file reports that include the preceding ~~following~~ information and data to the greatest extent practicable. Where a Utility is not able to provide the required information, the Company shall explain why it is unable to do so. Such reports must be filed annually on March 1st in the current docket, 24-288. Where applicable, Utilities must include data in spreadsheet (.xlsx) format as well as in tabulated form. If a 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.

4. After four years of DSRUP tariffed operation, each Utility shall file an evaluation of the Standards and any recommended changes with its annual report in Docket 24-288.

5. In addition to Utility evaluations, the DSRUP Standards are subject to refinement through Commission Order or through the Reactive Upgrade Workgroup with subsequent Commission approval. The Reactive Upgrade Workgroup shall be convened by Commission Staff and shall meet as necessary to refine and improve the Standards. Workgroup participants may reach out to Commission Staff to raise issues or concerns that may require the workgroup to reconvene.

6. The DSRUP shall be evaluated based on the proposed reporting requirements.

O. Dispute Resolution

1. Dispute resolution shall be consistent with the highlighted portions of Attachment B.

P. Tariff Implementation

1. These standards shall be implemented with each Utility through tariffs filed by each Utility.
2. The tariff filing shall include a Utility's DSRUP Agreement.

Attachment 2: Xcel Energy's Preferred Dispute Resolution Process for the DSRUP

Dispute Resolution Process for the Distribution System Reactive Upgrade Process (DSRUP)[1]

For Disputes Between Interconnection Customers (and Developers) and the Public Utility

Generally, follow the MN DIP process, except where shown in highlight below:

5.3 Disputes

5.3.1 The Parties agree to attempt to resolve all disputes arising out of the interconnection process (and the DSRUP) and associated study and Interconnection Agreements according to the provisions of this article and Minnesota Administrative Rules 7829.1500-7829.1900. More information on the Commission's Consumer Affairs Office dispute resolution services is available on the Commission's website: https://mn.gov/puc/consumers/help/complaint/

5.3.2 Prior to a written Notice of Dispute, the Party shall contact the other Party and raise the issue and the relief sought in an attempt to resolve the issue immediately.

5.3.3 In the event of a dispute, the disputing Party shall provide the other Party a written Notice of Dispute containing the relevant known facts pertaining to the dispute, the specific dispute and the relief sought, and express notice by the disputing Party that it is invoking the procedures under this article. The Interconnection Customer may utilize the Commission's Consumer Affairs Office's complaint/inquiry form and Informal Complaint dispute resolution process to assist with the written Notice of Dispute. The notice shall be sent to the non-disputing Party's email address and physical address set forth in the Interconnection Agreement or Interconnection Application, if there is no Interconnection Agreement. If the Interconnection Customer chooses not to utilize the Commission's Consumer Affair Office dispute resolution process, the Interconnection Customer shall provide an informational electronic copy of the Notice of Dispute to the Consumer Affairs Office at the Commission at consumer.puc@state.mn.us.

For Disputes relating to the DSRUP, it is mandatory to either complete the Commission's Consumer Affairs Office complaint/inquiry form or provide an informational copy to the CAO and this will provide notice to the Ombudsperson of the Dispute. ~~For the first three years of DSRUP implementation, a~~Any Dispute

[1] The process and standards approved by the Commission and outlined in Docket 24-288.

Xcel Energy modifications noted in red.

Attachment 2: Xcel Energy's Preferred Dispute Resolution Process for the DSRUP

regarding the DSRUP will not be logged as a complaint so that the Dispute will not count towards triggering service quality payments. Also, any Dispute relating to the DSRUP must be timely brought ("Timely Brought") in such a way so as to not further adversely impact other Interconnection Applications compared to if the Dispute had been brought in a timelier manner.

5.3.4 The non-disputing Party shall acknowledge the notice within three (3) Business Days of its receipt and identify a representative with the authority to make decisions for the non-disputing Party with respect to the dispute.

For Disputes relating to the DSRUP, if resolution of the Dispute might have a material impact on any other Interconnection Application, then that impacted Interconnection Application may be placed on hold until the Dispute is resolved.

5.3.5 The non-disputing Party shall provide the disputing Party with relevant regulatory and/or technical details and analysis regarding the Area EPS Operator interconnection requirements under dispute within ten (10) Business Days of the date of the Notice of Dispute.

If the Area EPS Operator believes that one or more other Interconnection Customers would be materially impacted by the resolution of a Dispute relating DSRUP, then the Area EPS Operator may as part of the 10 Business Day response above make any such Interconnection Customer a Party to the Dispute, and may provide pertinent details about the dispute to any Party to the Dispute including but not limited to as to any Party's position in the queue, name of any Party to the Dispute, and any such Party's assigned feeder and substation, date application was Deemed Complete, nameplate capacity of the Interconnection Application, etc. and an explanation of how each Party may be materially impacted by the resolution of the Dispute.

Within twenty (20) Business Days of the date of the Notice of Dispute, the Parties' authorized representatives will be required to meet and confer to try to resolve the dispute. Parties shall operate in good faith and use best efforts to resolve the dispute.

5.3.6 If a resolution is not reached in the thirty (30) Business Days from the date of the notice described in section 5.3.3, the Parties may 1) if mutually agreed, continue negotiations for up to an additional twenty (20) Business Days; or 2) either Party may request the Commission's Consumer Affairs Office provide mediation in an attempt to resolve the dispute within twenty (20) Business Days with the opportunity to extend this timeline upon mutual agreement. Alternatively, both Parties by mutual agreement may request mediation from an outside third-party mediator with costs to be shared equally between the Parties.

Xcel Energy modifications noted in red.

Attachment 2: Xcel Energy's Preferred Dispute Resolution Process for the DSRUP

In the case of a Dispute relating to the DSRUP, any Party may bring dispute relating to Reactive Cost Sharing to the Ombudsperson at the Commission's CAO office for mediation.

5.3.7 If the results of the mediation are not accepted by one or more Parties (or by any Party for a Dispute in the case of a and there is still disagreement, the dispute shall proceed to the Commission's Formal Complaint process as described in Minn. Rules 7829.1700-1900 unless mutually agreed to continue with informal dispute resolution.

5.3.8 At any time, either Party may file a complaint before the Commission pursuant to Minn. Stat. §216B.164, if applicable, and Commission rules outlined in Minn. Rules Ch. 7829.

Additional steps for Disputes relating to the DSRUP:

If the Dispute is not resolved following the above steps 5.3.1 to 5.3.6, then any Party may bring any Timely Brought Dispute relating to the DSRUP to the Commission for Expedited Dispute Resolution in the following way: File in a new Docket a Petition for Resolution of Dispute Relating to the DSRUP, include in that Petition all Parties to the Dispute as set forth above, and include in that Petition all pertinent facts. All Parties that are not Petitioners may be allowed 20 Business Days to submit their positions on the issue to the Commission, including where applicable a discussion on whether the Dispute has been Timely Brought. The Executive Secretary will determine if further rounds of comments are appropriate and will then set the matter for hearing. At hearing, the Commission may use its judgment on how the Dispute should be resolved, or whether further investigation is necessary. The Commission may determine whether the Dispute has not been Timely Brought and therefore is time barred.

Xcel Energy modifications noted in red.

Requirement No.	Requirement	Position	Reply Comments	Justification from Initial Comments
	Modifications proposed by the Company or other parties in Initial Comments are denoted in redline. Additional modifications we propose with these Reply Comments are denoted in blue redline format.			
B. Definitions				
Defined terms from the MN DIP have the same meanings here and are capitalized throughout the Standards below. Additionally, the Commission adopts the following definitions for the purposes of this proceeding:				
B.1	Annual Ratepayer Cost Cap: The total rolling annual cost of Upgrades that are not paid for by Reactive Cost Share Participants and that may be recovered from ratepayers under Commission-approved cost recovery methods.	Support		
B.2	Distributed Generation Project (Project): An energy generating system with a capacity no greater than ten megawatts.	Do not oppose	We supported this original definition in the draft generic Standards, but believe JSC/CEF's proposed modification below is reasonable and preferable.	
JSC/CEF B.2	Distributed Generation Project (Project): An energy generating system connected to the distribution system with a capacity no greater than ten megawatts.	Support	We prefer JSC/CEF's modified definition.	*n/a - new*
B.3	Distribution System Reactive Upgrade Process (DSRUP or Process): The process and operation of the "generic standards" envisioned by Section 53 of the 2024 Minnesota Session Laws, Regular Session, Chapter 126, Article 6 and approved by the Minnesota Public Utilities Commission.	Support		
B.4	Distribution System Reactive Upgrade Process Cost Share Agreement (DSRUP Agreement): The agreement between an Interconnection Customer and the Utility providing the Interconnection Customer's intention to participate in an Upgrade and to provide a Reactive Cost Share Contribution for an Upgrade with an open Mobilization Window.	Support		
B.5	Hosting Capacity: The maximum capacity of a utility distribution system to transport electricity at a specific location without compromising the safety or reliability of the distribution system.	Support		
B.6	Interconnection Application: An application that has been submitted to a utility for interconnection under MNDIP.	Support		
B.7	Interconnection Customer: A Distributed Generation Project owner that has submitted an Interconnection Application.	Support		
B.8	Minnesota Distributed Energy Resource Interconnection Agreement (MN DIA): The Agreement intended to provide for the Interconnection Customer to interconnect at the Point of Common Coupling and operate a Distributed Energy Resource with a Nameplate Rating of 10 Megawatts (MW) or less in parallel with the Area EPS at the location identified above and in the Interconnection Application. MN DIP Section 1.1.5 details when the Uniform Statewide Contract may replace the need for the MN DIA.	Support		
B.9	Minnesota Distributed Energy Resource Interconnection Process (MN DIP): The generic, statewide standards for the interconnection and parallel operation of distributed energy resources of no more than 10 MW. All regulated Area Electrical Power System (EPS) Operators are subject to the MN DIP.	Support		
B.10	Mobilization Threshold: The percentage of the estimated total Upgrade cost that must be committed in order for construction of the Upgrade to move forward.	Support		
B.11	Mobilization Window: When the Trigger Project by itself does not meet the Mobilization Threshold, the time period during which additional projects can commit to pay for Upgrade costs and those commitments will count towards the Upgrade's Mobilization Threshold.	Support		
B.12	Outstanding Costs: Any Reactive Cost Share Distribution Upgrade costs that are unrecovered from Reactive Cost Share Participants at any given time, after a Mobilization Threshold has been met and before the Payback Period has been closed.	Support		
B.13	Payback Period: The period of time, after the Mobilization Threshold has been met, allotted for the full value of the Upgrade to be paid for by Reactive Cost Share Participants.	Support		
B.14	Pro Rata Cost: The $/kWac rate calculated by dividing the total costs of the eligible Upgrade by the total kilowatts of Hosting Capacity created by the Upgrade.	Support		

Requirement No.	Requirement	Position	Reply Comments	Justification from Initial Comments
B.15	Reactive Cost Share Contribution: The contribution made by an Interconnection Customer toward an Upgrade. The amount is determined by multiplying the Pro Rata Cost by the kWac capacity of the facility seeking interconnection.	Support		
B.16	Reactive Cost Share Distribution Upgrade (Upgrade): A distribution Upgrade made under the DSRUP. This type of Upgrade must be a modification of a Utility's distribution system at a specific location that is necessary to allow the interconnection of Distributed Generation Projects by increasing Hosting Capacity at the applicable location, including but not limited to installing or modifying equipment at a substation or along a distribution line. Upgrade does not mean an expansion of hosting capacity dedicated solely to the interconnection of a single Distributed Generation Project.	Do not oppose		
Xcel B.16	Reactive Cost Share Distribution Upgrade (Upgrade): A distribution Upgrade made under the DSRUP. This type of Upgrade must be a modification of a Utility's distribution system at a specific location that is necessary to allow the interconnection of Distributed Generation Projects by increasing Hosting Capacity at the applicable location, including but not limited to installing or modifying equipment at a substation or along a distribution line. Upgrade does not mean an expansion of hosting capacity dedicated solely to the interconnection of a single Distributed Generation Project. Upgrade does not mean construction of a new substation for the sole purpose of allowing the interconnection of Distributed Generation Projects or other upgrades that do not align with MN DIP.	Support as modified	We suggest a further addition to our original modification, noted in blue. We offer this additional modification in the spirit of maintaining ongoing alignment with MN DIP in the future.	New substations driven exclusively by new DG should be excluded from reactive cost-sharing because substation costs would have an outsize adverse impact on non-participating customers. Ratepayers should not pay for decades of O&M for a substation that exists solely to serve DG interconnections and from which they are not necessarily benefiting. A new substation would include transmission-related cost components that we believe would not qualify for cost-sharing under the DSRUP statute. A new substation likely would take several years to plan and build, and those behind in queue would likely need to be placed on hold during this time period. Construction of a new substation would take up a considerable amount of the Company's limited design and construction resources that would otherwise be used on projects and initiatives identified through the Company's robust planning process. We offer this modification to the definition of "Upgrade" to reflect this exclusion.
B.17	Reactive Cost Share Participant: An Interconnection Customer who elects to participate in a Reactive Cost Share Distribution Upgrade with an open cost-share window and is responsible for paying a cost-share contribution.	Support		
B.18	Reactive Upgrade Workgroup: The workgroup created in Docket 24-288 to create the draft standards of the DSRUP.	Support		
B.19	Trigger Project: The initial Interconnection Application for interconnection for a Distributed Generation Project that alerted a Utility that an Upgrade is needed in order to accommodate the Trigger Project and any future interconnections at the applicable location.	Support		
B.20	Utility: A public utility, as defined in Minnesota Statutes, section 216B.02, subdivision 4, that provides electric service.	Support		
C. Upgrade Cost Thresholds				
1 must be adopted, and the Commission must choose one subpart.				
C.1	To qualify for the DSRUP, an Upgrade must have total project costs of:			
	a. at least $250,000	Oppose		Offering cost sharing for all Upgrades is not necessary; the market has shown its ability and willingness to cover upgrade costs, which is aligned with cost-causation principles. Small Upgrades generally do not create additional capacity that could benefit many different projects, limiting the benefits of cost-sharing. By making more Upgrades eligible for DSRUP, a lower Upgrade Cost Threshold would cause the Annual Ratepayer Cost Cap to be reached through a higher number of less impactful Upgrades that may not need cost sharing to move forward.
	OR			
	b. at least $1	Oppose		
	OR			
	c. at least $2,500,000	Support		The DSRUP should be used to clear the largest roadblocks to interconnection by enabling system upgrades that would generally not be feasible under the standard interconnection process due to high costs. A lower threshold would lead to more DSRUP-qualifying Upgrade projects, resulting in the Company reaching its Annual Ratepayer Cost Cap more quickly and thus precluding future, potentially more beneficial Upgrades from participating in DSRUP. A higher threshold of $2.5 million would serve as an important customer protection, ensuring that customers contribute only to larger upgrades that create additional capacity on the system for future projects (e.g., transformer upgrades, new feeders).
	OR			

Requirement No.	Requirement	Position	Reply Comments	Justification from Initial Comments
	d. $100,000	Oppose		See above
2 may be adopted with one subpart. If the Commission does not wish to set a maximum limit, it may simply not adopt 2.				
C.2	To qualify as an eligible Reactive Cost Share Distribution Upgrade, an Upgrade must cost no more than:			
	a. $300,000/MW$_{AC}$	Do Not Oppose	We reiterate our justification from Initial Comments and further note that setting a maximum limit would preclude larger projects from accessing cost sharing at all, even if 100% of the costs are covered by Reactive Cost Share Participants. In addition, setting a maximum cost would create uncertainty for the Company and participants if an Upgrade estimate is near this limit. Costs could increase for a variety of reasons during construction; the draft generic Standards do not contemplate what would happen if the final cost of an Upgrade came in above this maximum. It is not clear if such a scenario would create cost recovery risk for the Company, stranded assets, or sunk costs for Reactive Cost Share Participants. Further process would need to be developed.	
	OR			
	b. $600,000/MW	Do Not Oppose		
	OR			
	c. No maximum	Support		While the statute states that the tariff standards must establish a minimum level of upgrade costs, a maximum cost is not contemplated in the law and is not necessary. The prioritization process (section G) will serve to prevent the most costly, lower-benefit Upgrades from moving forward with ratepayer funds. The Commission need not adopt C.2.
D. Pro Rata Cost Calculation				
D.1	When a Trigger Project elects to initiate the DSRUP and become a Reactive Cost Share Participant, the Utility shall calculate the estimated Pro Rata Cost defined as the total estimated costs of the eligible Upgrade divided by the total kilowatts of Hosting Capacity created by the Upgrade.	Support	The Company's understanding is that this is a consensus item and no parties oppose this Requirement.	Provides important process clarity.
D.2	The estimated Pro Rata Cost shall be considered an estimate in the calculation of a particular Reactive Cost Share Customer's Reactive Cost Share Contribution until a final Pro Rata Cost is determined after the final bill of actual costs for the Upgrade is issued consistent with MN DIP 5.6.4.1. The Utility shall either refund any excess fees paid or assess each Reactive Cost Share Participant the remaining amount, based on the final Pro Rata Cost of the Upgrade. Refunded amounts shall be issued by the Utility within 30 Business Days after the issuance of the final bill of actual costs. Additional assessments shall be paid by Reactive Cost Share Participants within 30 Business Days after the issuance of the final bill of actual costs. Interconnection Customers that elect to become a Reactive Cost Share Participant following construction of the Upgrade will be assessed a Reactive Cost Share Contribution based on the final Pro Rata Costs.	Support	The Company's understanding is that this is a consensus item and no parties oppose this Requirement.	Consistent with MN DIP. Provides important process clarity.
D.3	Final Reactive Cost Share Contributions shall not exceed 125% of the estimated Reactive Cost Share Contribution assigned to a Reactive Cost Share Customer in an executed interconnection agreement	Oppose		The Company provides a good-faith, best estimate ("indicative estimate"). The indicative estimate is provided before the detailed design process, during which the Company talks to local Authorities Having Jurisdiction (AHJs) and completes other design details that affect cost. A variety of factors outside the Company's control can cause deviations from the indicative estimate (e.g., local mandates, supply chain constraints, etc.). If included, this requirement could require the Company to become more conservative in the indicative estimate stage. The Company must be able to plan and complete Upgrade projects to its safety, quality, and reliability standards. If the final cost contributions are capped, we would not be able to recover those costs from the cost share customer, causing the Company's overall cost of service to increase even if that extra cost could not be recovered directly from customers (as contemplated by Requirement D.4), violating cost-causation principles.
D.4	Final total costs of an Upgrade in excess of 125% of the estimated total Upgrade cost shall be borne by Utility shareholders rather than recovered through rates.	Oppose		
E. Interconnection Process				
E.1	The DSRUP can only be initiated when a Distributed Energy Project completes a Facilities Study, and the results of the study indicate an eligible Upgrade is required. The Interconnection Customer will be given 20 Business Days after a signature-ready MN DIA and signature-ready DSRUP Agreement are provided to the Interconnection Customer to choose one of the following options: a. Participate in the DSRUP and act as a Trigger Project by signing and funding the DSRUP Agreement; or b. Pay the full cost of the Upgrade as described in Section F2 by signing and funding the DSRUP Agreement; or c. Withdraw its application	Support		Provides important process clarity.

Requirement No.	Requirement	Position	Reply Comments	Justification from Initial Comments
JSC/CEF E.1	The DSRUP can only be initiated when a Distributed Energy Project completes a Facilities Study, and the results of the study indicate an eligible Upgrade is required. The Interconnection Customer will be given 20 Business Days after a signature-ready MN DIA and signature-ready DSRUP Agreement are provided to the Interconnection Customer to choose one of the following options: a. Participate in the DSRUP and act as a Trigger Project by signing and funding the DSRUP Agreement; or b. pay more than their project's Reactive Cost Share Contribution in order to reach the Mobilization Threshold; ~~b~~c. Pay the full cost of the Upgrade as described in Section F2 by signing and funding the DSRUP Agreement; or ~~c~~d. Withdraw its application	Oppose	We support Reactive Cost Share Participants being able to overpay, but this modification is unclear. This modification implies that if a Trigger Project pays more than its Reactive Cost Share Contribution, it does not need to sign the DSRUP Agreement. We do not believe that is the intent of the modification. Requirement H.8 states, "Any Reactive Cost Share Participant may pay more than their project's Reactive Cost Share Contribution in order to reach the Mobilization Threshold of an Upgrade." With Requirement H.8 [or OAG's modified H.8], a modification to this requirement is not necessary.	*n/a - new*
E.2	An Interconnection Application that triggers an Upgrade shall have the option to pay for the full Upgrade, foregoing the cost sharing process and thus paying in full for the additional capacity beyond their project's need. Should the Interconnection Customer choose to fund the full Upgrade cost and forgo the cost sharing process they shall not be entitled to use excess capacity created by the Upgrade or receive any compensation from future Interconnection Customers utilizing the capacity created by the Upgrade.	Support		Provides important process clarity.
JSC/CEF E.2	An Interconnection Application that triggers an Upgrade shall have the option to pay for the full Upgrade, foregoing the cost sharing process and thus paying in full for the additional capacity beyond their project's need. Should the Interconnection Customer choose to fund the full Upgrade cost and forgo the cost sharing process they shall not be entitled to use excess capacity created by the Upgrade or receive any compensation from future Interconnection Customers utilizing the capacity created by the Upgrade. However, within 20 Business days from the issuance of the notice by the Utility, the Reactive Cost Share Participants may elect to pay more than their project's Reactive Cost Share Contribution in order to reach the Mobilization Threshold.	Oppose	This modification is not clear and could create confusion by blending DSRUP Participants and projects that choose not to participate in DSRUP. Requirement H.8 states, "Any Reactive Cost Share Participant may pay more than their project's Reactive Cost Share Contribution in order to reach the Mobilization Threshold of an Upgrade." With Requirement H.8 [or OAG's modified H.8], a modification to this requirement is not necessary.	*n/a - new*
E.3	Interconnection Applications with capacity no greater than 40 kWac and do not have available Hosting Capacity to interconnect shall be offered the opportunity to participate in the DSRUP prior to Initial Review. These projects are still subject to the MN DIP process for reviewing, studying, and processing their Interconnection Application.	Oppose		The Company's understanding is that the goal of this requirement is to ensure that Interconnection Applications for small DG projects are alerted early in the process if the project is seeking to interconnect at a location where the DSRUP has been initiated. The language "offered the opportunity" to participate lacks clarity and alignment with the other requirements - specifically Requirement E.8.a, under which the small DG project would be required to participate in DSRUP or withdraw their application. The wording in this requirement implies that the applicant can decline to participate in the DSRUP but still move their application forward. Xcel E.3 seeks to add clarity and alignment with other requirements.
Xcel E.3	Interconnection Applications with capacity no greater than 40 kWac and do not have available Hosting Capacity to interconnect shall be informed prior to Initial Review of the likely need ~~offered the opportunity~~ to participate in the DSRUP ~~prior to Initial Review~~. These projects are still subject to the MN DIP process for reviewing, studying, and processing their Interconnection Application.	Support as modified		See above. This modification seeks to clarify - in alignment with Requirement E.8.a - that the Applicant would need to participate in DSRUP or withdraw their application if DSRUP had been initiated. This modification accomplishes the aim of alerting Applicants early in the process, while adding important clarity. We note that if a capacity reservation for small projects is adopted in the future, this scenario would be less likely.
The Commission must choose either subpart 4a or 4b.				
E.4	An Interconnection Application with a nameplate rating more than 40 kWac is eligible to participate in an active Mobilization Window:			
	a. Once its Interconnection Application has completed a System Impact Study and, if necessary, a Facilities Study as required by MN DIP.	Oppose		This requirement does not offer sufficient flexibility for the utility to complete all studies that could be necessary, such as an Internal Transmission Study or one required by the Midcontinent Independent System Operator (MISO).
	OR			
	b. After all applicable MN DIP studies have been completed.	Support	These Studies provide the Applicant with all the information they need to determine whether to proceed. Ensuring that the Applicant has the estimated cost information at this stage reduces the likelihood that a project may withdraw later in the process.	This requirement provides flexibility to conduct necessary studies such as an Internal Transmission Study or MISO study. Consistency with MN DIP is an important way to "future-proof" the DSRUP - limiting the potential need for DSRUP updates if MN DIP evolves.

Requirement No.	Requirement	Position	Reply Comments	Justification from Initial Comments
JSC/CEF E.4.c (New)	c. After it is deemed complete.	Oppose	Under this Requirement, the Interconnection Application would be able to participate as a Reactive Cost Share Participant before all studies are completed to determine the scope of that specific project's portion of the Upgrade, or other costs that may be required. The applicable MN DIP studies for that project could identify additional costs needed that do not qualify for DSRUP, such as line extension costs or transmission system upgrades, potentially making the project uneconomic. If these additional costs are not studied, identified, and made known to the Reactive Cost Share Participant until after the Mobilization Threshold has already been reached, the Participant may withdraw their project, dropping the percentage of committed funds below the Mobilization Threshold. In short, this Requirement would create complications in the process and increase administrative burden, and increase risk.	*n/a - new*
E.5	Utilities shall streamline System Impact Studies for Interconnection Applications in queue behind a Trigger Project in Upgrades with an active Mobilization Window to the extent practicable. For Interconnection Applications starting a System Impact Study after a Mobilization Threshold has been met, the Utility shall utilize the Trigger Project's System Impact Study to the extent practicable.	Support		Provides important process clarity.
E.6	Interconnection Agreements for Reactive Cost Share Participants shall not be tendered for signature until after the Mobilization Threshold has been met and any applicable cluster studies have been completed.	Support	The Company's understanding is that this is a consensus item and no parties oppose this Requirement.	Provides important process clarity.
E.7	Utility shall countersign all Interconnection Agreements within 5 business days after receiving all signed Interconnection Agreements from all Reactive Cost Share Participants that are participating in the Upgrade.	Support	The Company's understanding is that this is a consensus item and no parties oppose this Requirement.	Provides important process clarity.
E.8	Interconnection customers that elect to be a Reactive Cost Share Participant shall have their queue status updated to "Awaiting Cost Share Upgrade Selection" until the Interconnection Agreements for all Reactive Cost Share Participants that are participating in the Upgrade have been signed and countersigned by the Utility.	Support	The Company's understanding is that this is a consensus item and no parties oppose the first part of Requirement E.8; there are varying positions on the subparts of E.8.	Provides important process clarity.
	a. Interconnection Applications in the "Awaiting Cost Share Upgrade Selection" status will maintain their queue position, and the next-in-queue project will be processed and studied through MN DIP. After completion of the System Impact Study and, if necessary, Facilities Study, next-in-queue projects will be notified by the Utility with a signature-ready DSRUP agreement. Next-in-queue projects must sign the DSRUP Agreement and pay the administrative fee within 10 Business Days of receiving notification from the Utility, or withdraw	Support		Provides important process clarity.
JSC/CEF E.8.a	a. Interconnection Applications in the "Awaiting Cost Share Upgrade Selection" status will maintain their queue position, and the next-in-queue project will be processed and studied through MN DIP. After completion of the System Impact Study and, if necessary, Facilities Study, next-in-queue projects will be notified by the Utility with a signature-ready DSRUP agreement. Next-in-queue projects must sign the DSRUP Agreement and pay the administrative fee within 10 Business Days of receiving notification from the Utility, elect to pay more than their project's Reactive Cost Share Contribution in order to reach the Mobilization Threshold, or withdraw	Oppose	Participants that elect to pay more than their project's Reactive Cost Share Contribution will still need to sign the DSRUP Agreement and pay the administrative fee. As written, this requirement would exempt projects from the DSRUP Agreement and administrative fee if they elect to overpay. We do not believe this is the intent of the modification. Requirement H.8 states, "Any Reactive Cost Share Participant may pay more than their project's Reactive Cost Share Contribution in order to reach the Mobilization Threshold of an Upgrade." With Requirement H.8 [or OAG's modified H.8], a modification to this requirement is not necessary.	*n/a - new*
	b. Next-in-queue projects will not be allowed to pay the entire cost of the upgrade under section E.2.	Support	The Company's understanding is that this is a consensus item and no parties oppose this Requirement.	Provides important process clarity.
	c. If the System Impact Study and Facilities Study for a next-in-queue project determines that a new eligible Upgrade is required that does not fit within the scope of the existing Upgrade, then that next-in-queue project may choose to become a Trigger Project for the new upgrade following E.1 of the Standards.	Support	The Company's understanding is that this is a consensus item and no parties oppose this Requirement.	Provides important process clarity.
	d. Interconnection Applications that are processed as a next-in-queue project and have a capacity no greater than 40 kWac may proceed with interconnection if no upgrades are required and Hosting Capacity is available for applications with a capacity no greater than 40 kWac through a capacity reservation.	Support	"Capacity reservation" in this context refers to allowing small DER to exceed the Company's planning limit. The implementation of a system-wide capacity reservation is a topic that was deferred to Phase 2 of the proactive grid upgrade workgroup (Docket No. E002/CI-24-318). While this requirement mentions a capacity reservation, the Commission can adopt this requirement now without prejudging the outcome of Phase 2 of the proactive grid upgrades workgroup; should a capacity reservation not become reality (or if it is not applicable to all utilities), this requirement would simply become moot. (See below.)	Provides important process clarity.
JSC/CEF E.8.d	d. Interconnection Applications that are processed as a next-in-queue project and have a capacity no greater than 40 kWac may proceed with interconnection if no upgrades are required and Hosting Capacity is available for applications with a capacity no greater than 40 kWac ~~through a capacity reservation~~.	Do not oppose	JSC/CEF notes that this modification seeks to avoid potential conflict with future Commission decisions and process changes -- in other words, if a capacity reservation is not instituted. In practice, if a capacity reservation were not instituted, this scenario would not happen, so we do not believe JSC/CEF's modification changes the function of the requirement. As such, we do not oppose it.	

Requirement No.	Requirement	Position	Reply Comments	Justification from Initial Comments
E.9	After all Interconnection Agreements for all Reactive Cost Share Participants that are participating in an Upgrade are countersigned by the Utility, the Upgrade will proceed to detailed design and construction. Reactive Cost Share Participants will have their queue status updated to "Cost Share Upgrade In Progress." Until the Upgrade has been placed in-service. Interconnection Applications will have the estimated Reactive Cost Share Contribution included as an interconnection upgrade cost in the Interconnection Agreement. The Interconnection Agreement must be signed and timely paid consistent with MN DIP timelines.	Support		Provides important process clarity.
E.10	After an Upgrade has been placed in-service and before the Payback Period has closed, the queue will be processed following MN DIP. Interconnection Applications that are Deemed Complete during this time will have the estimated Reactive Cost Share Contribution, or the final Reactive Cost Share Contribution if available, included as an interconnection upgrade cost in the Interconnection Agreement. The Interconnection Agreement must be signed and timely paid consistent with MN DIP timelines.	Oppose	As we reviewed JSC/CEF's modification, we realized that this requirement should be applicable to any time before the Payback Period closes, not just between the Upgrade in-service date and the close of the Payback Period. We offer a modification as Xcel E.10 below.	[Support] Provides important process clarity.
JSC/CEF E.10	After an Upgrade has been placed in-service and before the Payback Period has closed, the queue will be processed following MN DIP. Interconnection Applications in queue following an Upgrade ~~that are Deemed Complete during this time~~ will have the estimated Reactive Cost Share Contribution, or the final Reactive Cost Share Contribution if available, included as an interconnection upgrade cost in the Interconnection Agreement. The Interconnection Agreement must be signed and timely paid consistent with MN DIP timelines.	Oppose	JSC/CEF notes that this modification is for clarity only, but we believe the second sentence is correct as originally written. A project could be in a long queue such that it would not be interconnecting after the Payback Period closes; therefore, the project should be in the Deemed Complete stage to be required to pay the Reactive Cost Share Contribution.	*n/a - new*
Xcel E.10	~~After an Upgrade has been placed in-service and before~~ Before the Payback Period has closed, the queue will be processed following MN DIP. Interconnection Applications that are Deemed Complete during this time will have the estimated Reactive Cost Share Contribution, or the final Reactive Cost Share Contribution if available, included as an interconnection upgrade cost in the Interconnection Agreement. The Interconnection Agreement must be signed and timely paid consistent with MN DIP timelines.	Support as modified	As we reviewed JSC/CEF's modification, we realized that this requirement should be applicable to any time before the Payback Period closes - not just between the Upgrade in-service date and the close of the Payback Period - because the queue will continue to be processed following MN DIP while the Upgrade is being constructed. As originally written, the requirement implies that queue processing would stop before the Upgrade is placed in service. We offer this modification to correctly reflect how the queue should continue to be processed.	*n/a - new*
F. Mobilization Threshold and Window				
The Commission must choose one subpart of 1.				
F.1	The Mobilization Threshold for an individual Upgrade is set at:			
	a. 25 percent of total Upgrade costs.	Oppose		This lower Mobilization Threshold creates the risk of stranded or underutilized assets that increase costs for non-participating customers. With a 25% mobilization threshold, an Upgrade would be constructed with 75% of the costs remaining. If sufficient follow-on projects do not arise to use the additional capacity and cover the remaining costs, customers would be left bearing a larger burden, paying up to 75% of the costs of an underutilized Upgrade. In addition, under a 25% Mobilization Threshold, up to 75% of the cost of each Upgrade would contribute to the Annual Ratepayer Cost Cap, which would lead to the cap being reached more quickly, thus reducing the number of Upgrades that could be covered under DSRUP.
	OR			
	b. 80 percent of total Upgrade costs.	Support		An 80% Mobilization Threshold ensures that most Upgrades are nearly fully utilized and funded through Reactive Cost Sharing Contributions, before ratepayer funds would be needed. Under an 80% threshold, more Upgrades could be funded under the same Annual Ratepayer Cost Cap, and the risk of stranded or underutilized assets would be reduced.
	OR			
	c. The Mobilization Thresholds shall be tiered based on cost per MW of capacity added by the Upgrade as follows: • $1/MW - $149,999/MW: 30% • $150,000/MW - $249,999/MW: 45% • $250,000/MW - $349,999/MW: 60% • $350,000/MW - $449,999/MW: 75% • $450,000/MW - $600,000/MW: 80%	Oppose		A tiered approach would be overly complex to administer and implement, particularly if and when cost estimates shift. As an example, if an Upgrade estimate is $325,000 and the Mobilization Threshold of 60% is reached, construction could begin. During construction, an unanticipated change could increase the cost estimate above $350,000, but the Upgrade has not reached the next-tier threshold of 75% of project costs committed; thus, the Upgrade would retroactively fall out of the Mobilization Threshold - yet in this example, construction has already begun. F.1.c is unnecessarily complex and would create complications, necessitating additional requirements and processes to clarify. In addition, as noted above, we have concerns about the risk to customers of underutilized assets at lower Mobilization Thresholds.
F.2	The Mobilization Window for an Upgrade shall remain open until an alteration in the electric distribution system requires a new distribution System Impact Study to confirm the accuracy or necessity of the previously identified Upgrade. When the Mobilization Threshold is met the Utility may conduct a new mandatory cluster study with the costs assigned to the relevant Cost Share Participants consistent with a Utility's Cluster Study guidelines and timelines. Refusal by a Reactive Cost Share Participant to pay for its share of the study cost will constitute withdrawal.	Support	The Company's understanding is that this is a consensus item and no parties oppose this Requirement.	This requirement is an important acknowledgment of the dynamic nature of the distribution system. New studies may be necessary to ensure accuracy and necessity of the Upgrade and to provide Cost Share Participants with the most up-to-date information. If the Commission chooses to allow the mobilization window to remain open indefinitely (i.e., if Requirement Xcel F.7 is not adopted), then this requirement becomes especially important.

Modifications proposed by the Company or other parties in Initial Comments are denoted in redline. Additional modifications we propose with these Reply Comments are denoted in blue redline format.

Requirement No.	Requirement	Position	Reply Comments	Justification from Initial Comments
F.3	If either of the scenarios described in 3a or 3b occurs in the steps following an Upgrade being selected in the Upgrade prioritization process, the Utility will issue notice to the Reactive Cost Share Participants participating in the Upgrade that the Upgrade will be moved back to an open Mobilization Window. Within 20 Business days from the issuance of the notice by the Utility, the Reactive Cost Share Participants may elect to pay more than their project's Reactive Cost Share Contribution in order to reach the Mobilization Threshold, or the Upgrade will be moved back to an open Mobilization Window. After an Upgrade is moved back to an open Mobilization Window, when the Mobilization Threshold has been met again, the Upgrade will advance to the prioritization selection process. a. A Reactive Cost Share Participant withdraws such that the mobilization threshold is no longer reached. b. The final cluster study cost estimate varies from the previous estimate such that the mobilization threshold is no longer reached.	Support	The Company's understanding is that this is a consensus item and no parties oppose this Requirement.	Provides important process clarity.
F.4	If either of the scenarios described in 4a or 4b occurs in the steps following an Upgrade being selected in the Upgrade prioritization process, the Upgrade will be reprioritized against the criteria in G.1 of the Standards. If the reprioritization results in the Upgrade no longer maintaining its priority, it will be reconsidered in the next prioritization process as described in G.4 of the Standards before proceeding.	Support		Provides important process clarity.
	a. A Reactive Cost Share Participant withdraws.	Support	The Company's understanding is that this is a consensus item and no parties oppose this Requirement.	Provides important process clarity.
	b. The final cluster study cost estimate varies from the previous estimate by more than 20%.	Support	This part of the requirement is necessary to ensure that the correct and latest information is used to prioritize the project, and also ensure that the amount of funds committed still reaches the Mobilization Threshold (if the estimate increases). JSC/CEF notes that the language in F.4.b could cause Upgrades to be stalled in a cycle of study and restudy due to basic accounting or estimation errors. While we believe basic accounting and estimation errors are uncommon and unlikely, an Upgrade should always be prioritized based on the most accurate information available and it is appropriate to re-prioritize if a cost estimate changes. When viewed together with Requirement G.5 (which creates a rebuttable presumption of prudence for upgrades selected through the prioritization process), this part of F.4 becomes particularly important, because it may no longer be prudent to go forward with an Upgrade for which costs have increased drastically, so the Company should not be required to go forward with such an Upgrade.	Provides important process clarity.
F.5	If an Upgrade is moved back to an open Mobilization Window after estimated Reactive Cost Share Contributions have been paid by a Reactive Cost Share Participant, the Utility shall issue refunds of the estimated Reactive Cost Share Contributions within 30 Business Days from the date the Utility notifies the Reactive Cost Share Participants that the Mobilization Window is being reopened.	Support	The Company's understanding is that this is a consensus item and no parties oppose this Requirement.	Provides important process clarity.
F.6	If a Mobilization Window remains open for more than two years, the Utility may consider Upgrade as a potential Proactive Upgrade in its next Proactive Upgrade Proposal under the framework established in Docket E002/CI-24-318.	Oppose		Any potential relationship or overlap between Proactive and Reactive Upgrades should be considered in the next phase of the Proactive Upgrades docket (Docket No. E002/CI-24-318). This requirement would functionally redefine "proactive" upgrade and thus needs to be considered in the Proactive Upgrades docket.
Xcel F.7 (New)	The Mobilization Window shall close if the Mobilization Threshold is not reached within two years.	Support		Under Requirement E.8.a, Interconnection Applications in queue after a Trigger Project would be required to participate in DSRUP or withdraw their application. If the Mobilization Window remains open indefinitely, an Upgrade could be "stuck" in an open Mobilization Window indefinitely due to a cost-prohibitive Upgrade not moving forward.
Xcel F.8 (New)	The Mobilization Window shall close if all Reactive Cost Share Participants withdraw.	Support		We believe this requirement should be explicit to help ensure consistency and clarity.
G. Upgrade Prioritization				
Some areas of the distribution system have long queues of interconnection projects trying to interconnect into systems that are capacity constrained. Utilities have a finite number of resources that can be allocated towards Upgrade construction. Since there will likely be several areas of the distribution system that will meet the mobilization threshold around the same time and there are limited construction resources, prioritization can help parse which upgrades should be constructed first. In the future, when there are not more upgrades than available resources, this DSRUP will have upgrades completed in a market-driven way. In other words, chronologically as upgrades meet their mobilization thresholds. These prioritization criteria will only be in effect when there are multiple upgrades to choose from that can't all be started in the same period.				We believe it is imperative that all Upgrades go through the prioritization process outlined in G.1.

Requirement No.	Requirement	Position	Reply Comments	Justification from Initial Comments
G.1	When there are multiple eligible Upgrades that have reached the Mobilization Threshold, their construction shall be prioritized based on the below-listed criteria. In the case different upgrades are tied or equal in a given criterion, the upgrade will be prioritized by the next following criterion. The criteria used to evaluate the upgrades shall adhere to the following order: a. The Upgrade with the highest percentage of developer-funded Upgrade cost b. Lowest cost per megawatt of capacity added by the Upgrade c. Most capacity constraints d. Clear optimization benefits for the grid	Support		
G.2	Notwithstanding the criteria listed in G1, where supply chain issues, permitting issues, or other issues that may delay an Upgrade by one year or longer are encountered, the Utility may remove the Upgrade from consideration until the next Upgrade prioritization review, and instead select the next highest priority Upgrade using the prioritization criteria.	Support	We continue to support this requirement as written because it is preferable to have an Upgrade move forward rather than be stalled by a delayed Upgrade. JSC/CEF suggests that this language is too ambiguous. We believe it provides sufficient clarity with a degree of flexibility for the Company to keep moving projects forward.	This requirement would limit delays for other Upgrades and projects; if one Upgrade is delayed for issues outside the Company's control, that delay would not need to cause delays for other Upgrades.
G.3	Following tariffed process initiation, every ____ the Utility shall review Upgrades that have met the Mobilization Threshold during the previous ____ months and prioritize them based on criteria in G1.			
	a. Three months	Oppose		A longer interval is appropriate to enable necessary studies to be completed and for the prioritization process to be more meaningful. (See comments below.)
	OR			
	b. Six Months	Support		Six months provides needed flexibility and ensures sufficient time to complete needed studies. At shorter intervals, studies may still be in progress. Conducting prioritization reviews every six months may also lead to more Upgrades being prioritized (versus a single Upgrade moving forward simply because no other Upgrades have reached this step), which would provide further assurance that the most beneficial and cost-effective Upgrades move forward first.
G.4	An initial prioritization shall occur utilizing the criteria in G1 within six months of tariffed DSRUP approval. Following initial prioritization governed by G1, Upgrades shall move forward on a first come, first serve basis. Prioritization shall only be used when Upgrades meet the Mobilization Threshold during the same period as set in Section G3.	Oppose		The prioritization process outlined in G.1 should be used continuously; a solely first-come, first-serve approach to upgrades may lead to a higher number of less effective Upgrades being constructed and funded in part by customers. (We note that in a scenario where only one Upgrade meets the Mobilization Threshold in the time period under G.3, the prioritization process would be moot.)
G.5	Approval through the prioritization process chosen in Section G shall create a rebuttable presumption of prudence in any cost recovery proceeding.	Do not oppose	We supported this Requirement in Initial Comments and continue to strongly support the creation of a rebuttable presumption of prudence; however, the first word "Approval" is not correct, as OAG's modification identifies. We offer a modified G.5 below to accurately reflect the function of the prioritization process.	[Support] DSRUP should use clearly established criteria -- as in G.1 -- for selecting Upgrades. Because the Company will have limited opportunity to control what Upgrades we build through the market-driven program, the Company needs to have a reasonable certainty for cost recovery. A rebuttable presumption of prudence is consistent with the Proactive Grid Upgrades framework approved by the Commission in Docket No. E002/CI-24-318 and is appropriate for DSRUP; we note a key difference between the Proactive framework and DSRUP is that the Commission will not approve these Upgrades before they move forward, because they are driven by the market. This further increases the importance of cost recovery certainty.
OAG G.5	~~Approval~~ Selection through the prioritization process chosen in Section G shall create a rebuttable presumption ~~of prudence~~ that pursuing construction of an approved Upgrade was prudent in any cost recovery proceeding. The utility retains the burden of proof.	Oppose	We disagree with OAG that a rebuttable presumption of prudence means that the utility would not be required to provide any information about upgrades when seeking cost recovery. The language in G.5 is not an advance determination of prudence. A rebuttable presumption of prudence is imperative for the Company for this market-driven program.	
Xcel G.5	~~Approval~~ Selection through the prioritization process chosen in Section G shall create a rebuttable presumption of prudence in any cost recovery proceeding.	Support as modified	OAG's modified G.5 includes an important correction to reflect the practical function of the prioritization process. The prioritization process leads to the selection of an Upgrade, not approval - the Company nor the Commission will specifically approve any Upgrade. We appreciate this edit from OAG and offer this modified version of G.5 to reflect that change, while retaining the rest of the original language.	

Modifications proposed by the Company or other parties in Initial Comments are denoted in redline. Additional modifications we propose with these Reply Comments are denoted in blue redline format.

Requirement No.	Requirement	Position	Reply Comments	Justification from Initial Comments
G.6	Complaints regarding the prioritization results shall be addressed through the Formal Complaint process as subject to Minn. Rules 7829.1700-.1900 rather than the DSRUP dispute resolution process.	Oppose		If adopted, this requirement would function as a *prohibition* on any other avenue for resolving disputes regarding prioritization. Minn. Stat. 216B.172, subd. 2, states that "A complainant must first attempt to resolve a dispute with a public utility[.]" Under the MN DIP dispute resolution process - on which the DSRUP dispute resolution process is based - any party can file a formal complaint at any time during the process, so the Formal Complaint avenue would still be available to parties. The Commission should not preclude parties from being able to work through the dispute resolution process in the case of a complaint regarding the prioritization process. Many disputes can be resolved between parties and without the need for any party to file a formal complaint.
H. Payment Details				
H.1	Interconnection Customers that have elected to participate in an Upgrade during an open Mobilization Window shall have an executed DSRUP Agreement to pay their Reactive Cost Share Contribution at the time the Interconnection Agreement is signed and paid consistent with MN DIP timelines.	Support	The Company's understanding is that this is a consensus item and no parties oppose this Requirement.	Consistent with MN DIP. Provides important process clarity.
H.2	Interconnection Customers shall pay a non-refundable administrative fee with each executed DSRUP Agreement to participate in an Upgrade during an open Mobilization Window. The Interconnection Customer may exit the DSRUP Agreement at any time but will not be refunded the administrative fee.	Support	The Company's understanding is that this is a consensus item and no parties oppose this Requirement.	Provides important process clarity. The Administrative Fee is an important component of the process that enables the Company to cover its costs. The Administrative Fee will be set as part of a subsequent tariff filing.
H.3	A DSRUP Agreement shall not be contingent upon any other DSRUP Agreement for another Upgrade.	Support	The Company's understanding is that this is a consensus item and no parties oppose this Requirement.	This requirement is relevant if a single project requires two Upgrades that are each subject to DSRUP. In that case, under this requirement the two DSRUP processes move independently.
The Commission must select 4 or 5.				
H.4	Reactive Cost Share Participants may withdraw after all Interconnection Agreements for all Reactive Cost Share Participants that are participating in an Upgrade are countersigned by the Utility but shall not receive a refund of their Reactive Cost Share Contribution.	Support	The Company's understanding is that this is a consensus item and no parties oppose this Requirement or support H.5 over H.4.	H.4 aligns with MN DIP and the current cluster study guidelines. H.4 is also consistent with an amendment to the MN Distributed Energy Resources Interconnection Agreement (MN DIA) filed in Docket No. E002/M-18-714 on May 29, 2023 and which is authorized to be used as no participant filed an objection to this amendment within 30 days of its filing. This authorized amendment can also be used for the Reactive Cost Share program and its provisions do not need to be changed to do so.
OR				
H.5	Reactive Cost Share Participants are not allowed to withdraw after all Interconnection Agreements for all Reactive Cost Share Participants that are participating in an Upgrade are countersigned by the Utility and shall be assessed a penalty by the Utility if they do.	Oppose	The Company's understanding is that this is a consensus item and no parties support this Requirement over H.4.	This requirement does not align with MN DIP. The Company believes that H.4 provides sufficient customer protection and disincentive for Reactive Cost Share Participants to withdraw; would be more administratively streamlined; and is - appropriately - consistent with MN DIP.
H.6	Reactive Cost Share Participants may choose to use surety bonds and/or letters of credit to pay for their cost share contribution with cash payments becoming due in alignment with utilities' actual spending/costs incurred.	Oppose		At the time the Cost Share Contribution would be due, each Reactive Cost Share Participant would have a signed Interconnection Agreement; that is, the Cost Share Contribution is paid at a relatively late stage in the process: After the Mobilization Threshold has been met, the Upgrade has been prioritized, and the final cluster study is complete. Receiving payment before construction begins is a reasonable and standard practice. MN DIP Section 5.6.4 provides an option for the Area EPS Operator to use the "Traditional Security" or "Modified Security" methods to pay; similarly for DSRUP, such option should be at the Area EPS Operator's discretion. MN DIP has no provision for acceptance of a surety bond as a method of security for payment of any amount due; requiring the Company to accept surety bonds would increase risk to customers and is not reasonable, particularly for a market-driven program.
H.7	The Utility shall track the funds via the initial invoice deposit and issue refunds to those that overpay.	Oppose		We support a requirement that ensures refunds are issued to those that overpay. This concept is well captured in H.8. The language in H.7 lacks clarity -- e.g., we are unsure what "initial invoice deposit" refers to -- and is unnecessary if H.8 is adopted.
H.8	Any Reactive Cost Share Participant may pay more than their project's Reactive Cost Share Contribution in order to reach the Mobilization Threshold of an Upgrade. This payment beyond their project's calculated Reactive Cost Share Contribution shall be refunded if additional Reactive Cost Share Contributions are received prior to the Payback Period closing. A refund shall be issued to the overpaying Reactive Cost Share Participant within 30 business days from the date a new Reactive Cost Share Contribution is collected by the Utility. The amount refunded to overpaying Reactive Cost Share Participant is determined by the Reactive Cost Share Contribution collected from the new Reactive Cost Share Participant, not exceeding the amount of excess payment remaining to be refunded. Any remaining excess payment is not refundable once the Payback Period closes. Once the Payback Period closes or the over-payer has been fully refunded the excess payment, all funds from subsequent Reactive Cost Share Participants shall be credited to ratepayers.	Oppose	We supported this requirement in Initial Comments, but now support OAG's modified H.8.	[Support] This requirement provides important process clarity, including specifying that refunds shall be issued to those that overpay.
OAG H.8	Any Reactive Cost Share Participant may pay more than their project's Reactive Cost Share Contribution in order to reach the Mobilization Threshold of an Upgrade. This payment beyond their project's calculated Reactive Cost Share Contribution shall be refunded if additional Reactive Cost Share Contributions are received prior to the Payback Period closing. A refund shall be issued to the overpaying Reactive Cost Share Participant within 30 business days from the date a new Reactive Cost Share Contribution is collected by the Utility. The amount refunded to overpaying Reactive Cost Share Participant is determined by the Reactive Cost Share Contribution collected from the new Reactive Cost Share Participant, not exceeding the amount of excess payment remaining to be refunded. Any remaining excess payment is not refundable once the Payback Period closes. Once ~~the Payback Period closes or~~ the over-payer has been fully refunded the excess payment, all funds from subsequent Reactive Cost Share Participants shall be credited to ratepayers.	Support	We support OAG's modification as it is more precise. As OAG noted in its Initial Comments, once the Payback Period closes, costs would no longer be collected from Reactive Cost Share Participants, so it is appropriate to delete the reference to the Payback Period in the last sentence. We still believe this requirement in general is necessary as it provides important process clarity. We also note that this requirement covers JSC/CEF's modifications to allow overpayments: the first sentence states that any Participant may pay more than their Reactive Cost Share Contribution.	*n/a - new*

Requirement No.	Requirement	Position	Reply Comments	Justification from Initial Comments
H.9	If two or more Reactive Cost Share Participants pay more than their projects' Reactive Cost Share Contribution obligations for a single Upgrade, the Utility shall refund such excess amounts in the order in which the excess payments were received. The reactive cost Share Participant whose excess payment was received first shall be refunded in full prior to the issuance of any refund to the Participant whose excess payment was received subsequently, and this sequence shall continue accordingly until all excess payments have been refunded.	Support	The Company's understanding is that this is a consensus item and no parties oppose this Requirement.	Provides important process clarity.
H.10	There may be cases where a Utility collects greater than 100% of the final Upgrade costs and over-paying Reactive Cost Share Participants have already been refunded. If this occurs the excess will be returned to ratepayers by reducing the Utility's total recovery of distribution capital costs of the DSRUP the next time it seeks recovery for Process's costs.	Support	The Company's understanding is that this is a consensus item and no parties oppose this Requirement.	Provides important process clarity.
H.11	Interconnection Applications under 40 kWac are exempt from paying a Reactive Cost Share Contribution if Hosting Capacity is available for Interconnection Applications under 40 kWac through a capacity reservation.	Support		"Capacity reservation" in this context refers to allowing small DER to exceed the Company's planning limit. The implementation of a system-wide capacity reservation is a topic that was deferred to Phase 2 of the proactive grid upgrade workgroup (Docket No. E002/CI-24-318). The Commission can adopt this requirement now without prejudging the outcome of Phase 2 of the proactive grid upgrades workgroup; should a capacity reservation not become reality (or if it is not applicable to all utilities), Requirement H.11 would simply be moot.
H.12	Reactive Cost Share Participants may use other, Utility-specific, cost sharing programs to fund their Reactive Cost Share Contribution where applicable and with subsequent approval in those relevant Utility-specific cost sharing program docket proceedings.	Support	The Company's understanding is that this is a consensus item and no parties oppose this Requirement.	While this requirement is not specific to small DER as written, this requirement is designed to account for programs like the small DER cost sharing program. A capacity reservation will help limit when small DG projects would need to bear a share of the Upgrade cost, but in cases where a small project would need to contribute to an Upgrade, this requirement leaves open options to ease the burden on small projects.
I. Payback Period				
The Commission must choose one of the subparts of 1 and of 2.				
I.1	The Payback Period shall remain open once the Mobilization Threshold is reached and remains open for:			
	a. A minimum of five years from the Upgrade's in-service date.	Oppose		Requiring a minimum Payback Period duration is unnecessary and counterproductive; there is no need to keep the Payback Period open if the Upgrade costs have been fully recovered from Reactive Cost Share Participants. In practice, a minimum Payback Period would create variable Payback periods, which would introduce unnecessary complexity and burden in administration, and is less consistent and clear for Reactive Cost Share Participants.
	i. If at least 75% of the costs of the Reactive Distribution Upgrade have not been recovered after five years, the Payback Period is automatically extended by an additional three years.	Oppose	While we oppose 1.a overall, we oppose this sub-requirement particularly because it would be unnecessarily complicated to administer, and it would be less clear to Reactive Cost Share Participants and other Interconnection Customers trying to plan for projects and participation in DSRUP.	
	OR			
	b. A minimum of ten years from the Upgrade's in-service date.	Oppose		Requiring a minimum Payback Period duration is unnecessary and counterproductive; there is no need to keep the Payback Period open if the Upgrade costs have been fully recovered from Reactive Cost Share Participants.
	OR			
	c. Until 100% of Upgrade costs are recovered from Interconnection Customers.	Oppose		100% of upgrade costs may never be recovered from Interconnection Customers. Under this requirement, the Payback Period would effectively be open for the life of the Upgrade. There is a high likelihood that the distribution system will evolve and be reconfigured over that period. In that case, participants may be paying pro rata fees even when the Upgrade no longer provides the benefit as originally designed. due to ongoing changes in the system.
	OR			
	d. No more than ten years from the Upgrade's in-service date	Support		The Payback Period should be long enough to give sufficient time for new projects to participate and contribute to the Upgrade costs, but not so long that the system has changed (e.g., new load, different load shapes, other projects, etc.) such that the Upgrade may no longer be benefiting future projects. This requirement is also consistent with the process for Proactive Upgrades (Docket No. E002/CI-24-318).
I.2	The Payback Period shall end if:			The Payback Period should end if *either* I.2.a *or* I.2.b is true. We provide a modification to I.2.a below to add one terminology clarification and clarify that either part should be true before the Payback Period ends.
	a. The Hosting created by the Upgrade is fully utilized by Reactive Cost Share Participants and all over-payers have been fully refunded the amounts above their Reactive Cost Share Contribution.	Do not oppose	OAG opposes this Requirement as conflicting with Requirement H.10 and states that it may not make ratepayers whole. We disagree and believe Requirement H.10 effectively stands on its own, and other Requirements -- namely H.8 and K.6 -- would ensure that Reactive Cost Share Contributions are credited to ratepayers. Both parts of I.2 are necessary to enable the Payback Period to function logically and ensure space in the Annual Ratepayer Cost Cap can open up per Requirement J.4. As noted below, OAG (and others) supports part b of I.2, but OAG does not support a maximum duration in I.1, rendering the Payback Period meaningless under OAG's recommendation.	As noted above, Xcel I.2.a modification reflects a terminology clarification (Hosting Capacity), and clarifies that either I.2.a or I.2.b must be true for the Payback Period to end.
Xcel I.2.a	a. The Hosting Capacity created by the Upgrade is fully utilized by Reactive Cost Share Participants and all over-payers have been fully refunded the amounts above their Reactive Cost Share Contribution~~.~~, or	Support as modified		

Requirement No.	Requirement	Position	Reply Comments	Justification from Initial Comments
	b. The duration of the Payback Period defined in I.1 has elapsed.	Support	The Company's understanding is that this is a consensus item and no parties oppose this Requirement. However, we note that other parties support *minimum* Payback Periods in I.1, so the Payback Period would never elapse under I.1 alone. In order for this Requirement to function, there must be a maximum Payback Period defined in I.1.	See above
I.3	All Interconnection Applications that are in the Deemed Complete state within the Payback Period shall be subject to paying their Reactive Cost Share Contribution.	Support	OAG states this requirement is unclear and "Deemed Complete" lacks definition. We offer a modification as Xcel I.3 to refer to MN DIP. JSC/CEF states that this requirement lacks clarity and an Interconnection Applicant may choose not to opt in. On the contrary, as in E.8.a, an Applicant must participate or withdraw (unless the project is 40 kW or less and there is capacity available under a capacity reservation, as in Requirement H.11), and cannot choose *not* to participate. Our modified I.3 seeks to clarify this as well.	Provides important process clarity and eliminates ambiguity surrounding when a project is subject to paying its Reactive Cost Share Contribution: If there is any Hosting Capacity sill available when the Payback Period closes, Interconnection Applications that in the Deemed Complete state will not be able to access that capacity at no cost.
Xcel I.3	All Interconnection Applications that are in the Deemed Complete state, as defined in MN DIP, within the Payback Period shall be subject to paying their Reactive Cost Share Contribution, unless otherwise exempted under Section [H].	Support	We offer a modification as Xcel I.3 to refer to MN DIP, in response to OAG's comment that the original requirement is unclear with regard to the definition of "Deemed Complete". This modification also seeks to clarify that all Interconnection Applications in the Deemed Complete state during the Payback Period must participate unless exempt through a capacity reservation.	*n/a - new*
J. Annual Ratepayer Cost Cap				
The Annual Ratepayer Cost Cap is only referring to the total annual amount of potential Upgrade costs that may be allocated to ratepayers. It is not the "operational budget" of the DSRUP as a whole. The "Operational Budget" is theoretically how much money, on an annual rolling basis, is being spent on reactive distribution upgrades assuming the Annual Ratepayer Cost Cap is met.				
The Commission must choose either 1 or 2. If it chooses 2, it must select either 2.a or 2.b.				
J.1	The Commission shall decide the Annual Ratepayer Cost Cap for Utility in a tariff filing upon approval of that Utility's DSRUP.	Support		Keeping the Annual Ratepayer Cost Cap in the utility's tariff filings provides important flexibility for all utilities. Procedurally, we also believe this approach better aligns with J.3 below.
OR				
J.2	The Annual Ratepayer Cost Cap shall not exceed _____ % of the annual average of the Utility's forecasted 5-year distribution capital budget from its most recent Integrated Distribution Plan.			Should the Commission choose to adopt J.2, we prefer J.2.a.
	a. 2 percent	Do not oppose		While we believe 2 percent is reasonable for Xcel Energy at this time, it may not be appropriate for all utilities or at all points in the future. As a point of reference, this amount would be approximately $17.9 million if DSRUP began today. The annual average of the Company's forecasted five-year distribution capital budget from our most recent Integrated Resource Plan, filed October 31, 2025 in Docket No. E002/M-25-142, is $896.7 million.
	OR			
	b. 11 percent; or a percent that will equal $95 million for Xcel	Oppose		An Annual Ratepayer Cost Cap at $95 million presents a high ratepayer risk and is impracticable to implement. $95M is a significant amount of the Company's finite design and construction resources that would be dedicated to building these Upgrades. This would effectively pull resources away from other important investments we have budgeted, as shown in our 2025 IDP.
J.3	The Commission intends that the Annual Ratepayer Cost Cap will remain in place for at least 24 months since the most recent change to the cost cap went into effect before the Commission considers modifications. A Utility, prospective Trigger Projects, and ratepayer advocates may request a modification to the Annual Ratepayer Cost Cap. In determining whether to change the Annual Ratepayer Cost Cap, the Commission shall consider, at a minimum, previous and future ratepayer costs and risks arising from the Utility's DSRUP, total pending cost share contributions, and the demand for new Upgrades.	Support		This requirement best aligns with J.1. An update to the Annual Ratepayer Cost Cap in the utility's DSRUP tariff would require a Petition to the Commission. Leaving the Cost Cap in place for at least 24 months is a reasonable approach to limit administrative burden while managing risk to the Company and customers.
J.4	The Outstanding Costs of constructed Upgrades that have not been paid for by Reactive Cost Share Contributions shall count towards the Annual Ratepayer Cost Cap.	Support	The Company's understanding is that this is a consensus item and no parties oppose this Requirement.	Provides important clarification on how the Cost Cap functions.
	a. Costs of Upgrades that have not been paid for by Reactive Cost Share Participants upon the Payback Period closing shall be removed from the Annual Ratepayer Cost Cap.	Support		Provides important clarification on how the Cost Cap functions.
J.5	Once the Annual Ratepayer Cost Cap is reached, the Mobilization Threshold for all pending Upgrades is set to 100 percent until the total amount recoverable from ratepayers drops below the cap. As available space opens up within the cost cap, projects transitioning back to the standard Mobilization Threshold shall follow existing prioritization processes.	Oppose		Under the Standards as outlined to this point, once an Upgrade reaches the Mobilization Threshold (regardless of what the Threshold is), it would go through the prioritization process in G.1. We support the Mobilization Threshold increasing to 100 percent once the Cost Cap is reached, but the second sentence is not necessary and lacks clarity. An Upgrade that reaches a 100 percent Mobilization Threshold should not need to transition back to the Standard Mobilization threshold in order to go through the prioritization process. Alternatively, J.5 as

Requirement No.	Requirement	Position	Reply Comments	Justification from Initial Comments
Xcel J.5	Once the Annual Ratepayer Cost Cap is reached, the Mobilization Threshold for all pending Upgrades is set to 100 percent until the total amount recoverable from ratepayers drops below the cap. ~~As available space opens up within the cost cap, projects transitioning back to the standard Mobilization Threshold shall follow existing prioritization processes.~~	Support as modified		Mobilization threshold in order to go through the prioritization process. Alternatively, J.5 as written could be read as implying that any Upgrade that reaches the 100 percent Mobilization Threshold would *not* go through the prioritization process, and would move straight to construction after completion of the cluster study. The Standards should require *all* Upgrades to go through the prioritization process once they reach the Mobilization Threshold - regardless of what the Mobilization Threshold is set at. This is an important Standard that serves to ensure the most beneficial Upgrades move to construction first. In practice, an Upgrade with a higher percentage (i.e., 100%) of committed developer funds would result in a higher priority based on the process outlined in G.1, but we think it is important to ensure that J.5 does not imply that any Upgrade would *not* go through the prioritization process. Striking the last sentence of this requirement would be clearer while maintaining the integrity of the Cost Cap. We offer a modification to this effect as Xcel J.5.
K. Cost Recovery				
If the Commission chooses 1, it must also choose 2 or 3. If the Commission chooses 3, it must choose 3a or 3b. 3c is optional.				
K.1	Outstanding costs will not be eligible for rate recovery for the first five years of the Payback Period. After five years, the remainder of the outstanding costs shall be eligible for cost recovery.	Oppose	We reiterate that this Requirement is not in line with the language in statute. The Annual Ratepayer Cost Cap and Mobilization Threshold, along with the Upgrade Cost Threshold, are the appropriate and statute-aligned ways to mitigate impacts -- including near-term impacts -- on non-participating customers.	This requirement does not align with the statutory language, which "allows the utility to recover *on a timely basis* the costs of upgrades that are not allocated to participating distributed generation facilities under the commission order issued in docket No. E002, E015, or E017/CI-24-288" (emphasis added). (Minn. Stat. 216B.16, subd. 7b(b)(6).) Consistent with the law, the Company should be able to recover costs without delay or deferral. Deferred accounting should be applied in limited, extenuating circumstances, as the Commission has done in the past. Applying deferred accounting to individual Upgrades would not only be counter to Minnesota law, but it would be inconsistent with ratemaking principles and Commission precedent.
AND				
K.2	The Utility will not accrue carrying costs during the first five years of the Payback Period.	Oppose		As noted above, this requirement is not aligned with Minnesota law. The Company should be able to recover on a timely basis all costs associated with implementing this market-driven program.
OR				
K.3	The utility will accrue carrying costs during the first five years of the Payback Period. The percentage rate for calculating carrying costs shall be the ______.			
	a. utility's authorized Weighted Average Cost of Capital from the most recently approved rate case	Do not oppose		While we strongly oppose K.1, should the Commission choose K.1, the Company should be able to recover carrying costs and we prefer K.3.a.
	OR			
	b. utility's long-term cost of debt	Oppose		While we strongly oppose K.1, should the Commission choose K.1, the Company should be able to recover carrying costs, but using long-term cost of debt is not appropriate because it is not representative of the entire capital mix that the Company deploys to raise capital for its utility investments.
	c. Carrying costs shall not be capitalized. Carrying costs may be recovered through the Utility's Transmission Cost Recovery rider petition.	Do not oppose		While we strongly oppose K.1, should the Commission choose K.1, the Company should be able to recover carrying costs and we prefer K.3.a. K.3.c is not necessary because Minnesota law allows recovery through the Transmission Cost Recovery Rider and carrying costs are not capitalized.
K.4	Projects enabled by Upgrades that interconnect after the initial five years of the Payback Period has closed shall still be required to pay a Reactive Cost Share Contribution until the close of the Payback Period. Reactive Cost Share Contributions paid after the initial five years of the Payback Period shall be returned to ratepayers by paying down the remaining rate base of the Upgrade.	Oppose		This requirement is duplicative and unnecessary. The first sentence is unclear and unnecessary because all Reactive Cost Share Participants would be required to pay their Reactive Cost Share Contribution under Section I; it is not clear what is meant by "...after the initial five years of the Payback Period has closed." Costs would be collected during the Payback Period regardless of the status of cost recovery from ratepayers. The second sentence is unnecessary because the method of returning costs to ratepayers is covered under K.6.

Requirement No.	Requirement	Position	Reply Comments	Justification from Initial Comments
The Commission must choose at least one of the options under 5.				
K.5	A Utility may petition to recover outstanding costs through any or all of the following (but without any double recovery):			
	a. Through a general rate case.	Support		Remaining DSRUP costs after the Payback Period closes would be rolled into our rate base and included in a rate case, and no longer recovered through the Transmission Cost Recovery Rider.
	b. Through its Transmission Cost Recovery Rider pursuant to Minn. Stat. 216B.16, Subd. 7b, paragraph (b), clause 6.	Support	The Company's understanding is that this is a consensus item and no parties oppose this Requirement.	Necessary and allowed by Minnesota law.
	c. Through deferred accounting.	Oppose		Deferred accounting is unnecessary and would add complexity and cost. Minnesota law allows for timely recovery of DSRUP costs. As noted above, deferred accounting should be applied in limited, extenuating circumstances, as the Commission has done in the past. Applying deferred accounting to individual Upgrades would not only be counter to Minnesota law, but it would be inconsistent with ratemaking principles and Commission precedent.
	d. Through invoices for DER projects.	Oppose		This approach is unnecessary, unclear, and overly complex, and would undermine the spirit of the DSRUP itself. Reactive Cost Share Participants would cover their pro rata share of at least 80% of the upgrade costs (under the Company's preferred Mobilization Threshold in F.1.b); it is not clear if this requirement is suggesting that *non-participating* DER projects would cover the remaining costs (or how such requirement would function). Furthermore, a utility petitioning to recover outstanding costs through project invoices would be burdensome for the utility, parties, and the Commission, which would need to then conduct a procedural process and issue an Order on each invoice.
The Commission must choose 6a or 6b				
K.6	6. All Reactive Cost Share Contributions collected from Reactive Cost Share Participants shall be collected during the Payback Period and shall be:			
	a. Returned to ratepayers as an offset to the revenue requirements of Reactive Cost Share Distribution Upgrade.	Support		This requirement is consistent with the Proactive Upgrades Framework (Docket No. E002/CI-24-318) and provides needed clarity on the mechanism under which costs would be returned to ratepayers.
	OR			
	b. Used to offset the rate base amount of the Upgrade until the upgraded assets are fully paid down, or the Payback Window closes.	Oppose		The Company prefers K.6.a over this pathway, which would require the Company to establish new accounting procedures and add a level of complexity that would create administrative burden compared to K.6.a.
L. Cost Allocation				
1 and 2 are alternatives. 3 can be adopted with either combination				
L.1	Costs recovered from ratepayers shall be treated consistent with the most recently approved rate case allocators and established revenue requirement procedures. Parties to a Utility's rate case or other cost recovery proceeding may request that the Commission establish a different cost allocation and procedures for DSRUP Upgrades.	Support		This requirement is consistent with standard practice and procedures and thus would be straightforward to administer. While we do not believe a different cost allocation or procedure will be necessary for DSRUP, a rate case is the appropriate venue in which to review these issues.
OR				

Requirement No.	Requirement	Position	Reply Comments	Justification from Initial Comments
L.2	For Reactive Cost Share Distribution Upgrades primarily serving large commercial and/or industrial customers, Upgrades shall be tracked separately from other rate-base assets and costs not paid for by Cost Share Contributions shall be allocated to the large commercial and industrial classes contributing to the need for or benefiting from the Upgrade. For all Upgrades that do not primarily serve large commercial and/or industrial customers, costs will be allocated according to the most recently approved rate case allocators and revenue requirement procedures. Parties to a Utility's rate case may request that the Commission establish a different cost allocation and procedures for DSRUP Upgrades.	Oppose	We continue to support using cost allocators consistent with the most recently approved rate case as in L.1. JSC/CEF suggests that project-specific allocations could be updated in a rate case; however, under our preferred generic Standards and as allowed by law, recovery of Outstanding Costs would begin in the TCR Rider as the Company incurs costs, so if this requirement is adopted, it would necessitate revisions to cost allocations outside of the rate case process, which is inconsistent with longstanding Commission precedent and is inefficient. OAG and DOC support this requirement but do not opine on the mechanism that could be used to update cost allocations over time. As emphasized in our Initial Comments, this raises procedural questions and issues that would complicate the administration of the program.	We oppose this requirement for two reasons: First, the requirement is unclear and would create policy uncertainty. Defining "primarily serving" would be difficult in because the Upgrade would include multiple projects likely serving multiple customers or purposes. This lack of definition could also add an unnecessary level of contentiousness and complexity to the process if there is a disagreement on whether a project "primarily serves" commercial and/or industrial customers. Allocators should be updated in a rate case. Second, tracking these Upgrades separately on a project level raises several questions as to how a project-specific cost allocation procedure would be administered at the Commission and if each Upgrade project's cost allocation would require Commission approval. It is also unclear at what interval the Company would need to re-assess project-specific cost allocation. Approval of L.2 would add another layer of new process and administration that may further delay and complicate the DSRUP program administration process.
L.3	To the extent that DSRUP Upgrade costs are allocated to ratepayers, the Utility shall identify and mitigate adverse bill impacts on under-resourced customers and/or small businesses.	Oppose		We support mitigating adverse bill impacts on under-resourced customers and small businesses; this requirement is unnecessary. The Mobilization Threshold and Annual Ratepayer Cost Cap are the appropriate instruments to consider and use to mitigate adverse bill impacts. As a practical matter and as noted above, all costs allocated to ratepayers should only use existing cost allocators from an approved rate case. There is no practical way to change the allocation of costs in this docket, so in that context, it is not clear what "mitigating" would mean for or require of the Company.
M. Publication of DSRUP Information and Data				
M.1	Utilities shall make all reasonable efforts to publish the feeders and/or substations that have an open Mobilization Window and the availability of potential Upgrades where there is an open Mobilization Window as well as where there is an Upgrade already constructed that still has available hosting capacity remaining. Utilities shall publish the following information on a monthly basis for each active Upgrade location: a. The $/kW Pro Rata Cost to participate in the Upgrade b. Start and end dates of the Mobilization Window c. Start and end dates of the Payback Period d. The feeders and/or substations that have an open Mobilization Window e. The maximum amount of distribution capacity that could be created by the Upgrade f. Status of the Mobilization Threshold i. How many projects have opted in ii. The capacity they have taken up iii. The progress, in percentage, towards the Mobilization Threshold	Support	The Company's understanding is that this is a consensus item and no parties oppose this Requirement.	We support publishing this information, and the Requirement language provides sufficient flexibility.
M.2	The information in M1 shall be included in Hosting Capacity maps.	Oppose		The Company's hosting capacity map includes a significant amount of data that can be difficult to navigate and locate the most relevant data (We plan to host additional training sessions in the future to help users navigate the map most effectively.) Putting this data into the hosting capacity map would require investment of time and money that we believe is unnecessary because the information can be provided in a spreadsheet, consistent with the presentation of the monthly MN DIP queue report. Not including this requirement in the Standards would not preclude the Company from including this information in Hosting Capacity maps in the future if appropriate, but it should not be a requirement.
M.3	The information in M1 shall be listed on a spreadsheet.	Support	The Company's understanding is that this is a consensus item and no parties oppose this Requirement.	Listing this information in a publicly available spreadsheet is straightforward and consistent with the presentation of the monthly MN DIP queue report.
N. Reporting and Process Evaluation				
N.1	Utilities shall file an annual compliance filing in Docket 24-288 the following reporting requirements:	Support	The Company's understanding is that N.1, with its subparts, is a consensus item and no parties oppose this Requirement.	These reporting requirements are reasonable; we note that much of this information will be reported in the Company's annual Transmission Cost Recovery (TCR) Rider filing. We note below which items we anticipate would be reported in the TCR filing for any Upgrades whose costs are included in the TCR.
	a. List of ongoing projects by feeder and status (waiting for Mobilization Threshold to be reached, Upgrades in progress, post-construction Mobilization Window)	Support		
	b. Status of the Annual Ratepayer Cost Cap (how much $ space is available)	Support		Included in TCR filing
	c. Revenue requirements	Support		Included in TCR filing
	d. Impact to the Annual Ratepayer Cost Cap from each project including a forecast of cap space (assuming no new cost share customers interconnect)	Support		

Modifications proposed by the Company or other parties in Initial Comments are denoted in redline. Additional modifications we propose with these Reply Comments are denoted in blue redline format.

Requirement No.	Requirement	Position	Reply Comments	Justification from Initial Comments
	e. Total costs allocated to ratepayers by the DSRUP	Support		Included in TCR filing
	f. Total capacity (kWac) added by the DSRUP	Support		
	g. Total cumulative capacity (kWac) added by DSRUP	Support		
	h. Total amount funded by Reactive Cost Share Contributions	Support		Included in TCR filing
	i. Details about each individual Upgrade made, including	Support		
	i. Capacity added	Support		
	ii. Total Cost (estimated, final), Pro Rata Cost (estimated, final)	Support		
	iii. Trigger date, construction date, etc. (length to Mobilization Threshold)	Support		
	iv. How many projects were involved, their sizes	Support		
	j. The monetary benefit to ratepayers as a result of Upgrades that were more than 100% funded.	Support		
	k. The results of upgrade prioritization process for each Upgrade.	Support		
N.2	Utilities must file reports that include the preceding ~~following~~ information and data to the greatest extent practicable. Where a Utility is not able to provide the required information, the Company shall explain why it is unable to do so. Such reports must be filed annually on March 1st in the current docket, 24-288. Where applicable, Utilities must include data in spreadsheet (.xlsx) format as well as in tabulated form. If a 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.	Support as modified	The Company's understanding is that this is a consensus item and no parties oppose this Requirement, notwithstanding our friendly amendment.	We support this requirement and offer a minor correction to reflect the latest requirement numbering.
N.3	The Utility shall also include a summary of the DSRUP information in its Integrated Distribution Plan, including total projects triggered, total projects constructed, what portion of the Annual Ratepayer Cost Cap has been used, and other key metrics.	Oppose		This reporting would be duplicative of the report that will be filed annually on March 1 under Requirements N.1 and N.2. As noted above, some of the same information would also be included in the Company's annual Transmission Cost Recovery Rider filing.
N.4	After four years of DSRUP tariffed operation, each Utility shall file an evaluation of the Standards and any recommended changes with its annual report in Docket 24-288.	Support	The Company's understanding is that this is a consensus item and no parties oppose this Requirement.	Evaluating the Standards is important. Four years is an appropriate length of time to allow the process to ramp up and achieve consistent operation.
N.5	In addition to Utility evaluations, the DSRUP Standards are subject to refinement through Commission Order or through the Reactive Upgrade Workgroup with subsequent Commission approval. The Reactive Upgrade Workgroup shall be convened by Commission Staff and shall meet as necessary to refine and improve the Standards. Workgroup participants may reach out to Commission Staff to raise issues or concerns that may require the workgroup to reconvene.	Support	The Company's understanding is that this is a consensus item and no parties oppose this Requirement.	We support ongoing convening of the Workgroup.
N.6	The DSRUP shall be evaluated based on the proposed reporting requirements.	Support	The Company's understanding is that this is a consensus item and no parties oppose this Requirement.	Explicit evaluation factors provide important clarity.
O. Dispute Resolution				
O.1	Dispute resolution shall be consistent with the highlighted portions of Attachment B.	Support		See "Att. B - Xcel Energy Position"
P. Tariff Implementation				
P.1	These standards shall be implemented with each Utility through tariffs filed by each Utility.	Support	The Company's understanding is that this is a consensus item and no parties oppose this Requirement.	Important clarification
P.2	The tariff filing shall include a Utility's DSRUP Agreement.	Support	The Company's understanding is that this is a consensus item and no parties oppose this Requirement.	Important clarification
Other Issues				
			As a threshold matter, these topics are broader than the issue at hand in this proceeding - interconnection cost sharing - and would impact MN DIP and other parties not involved in this docket. As such, these suggested requirements should not be considered as part of this docket.	
JSC/CEF 1	Increase Detail in Impact Study Cost Estimates: Require utilities to provide itemized, equipment level cost breakdowns (including labor, materials, and allowable contingency) in their cost estimates for distribution upgrades.	Oppose	Providing or publishing this detail would violate our contractual obligations with vendors. Existing systems and tools do not track this level of detail, as many of the invoices received from vendors lump various activities together. We provide several details to interconnection customers, including technical rationale and costs for applications that require a supplemental review as well as a Scope of Work for small DER	*n/a - new*
JSC/CEF 2	Establish Annual Cost Matrix Filings: Direct Minnesota's utilities to publish and update matrices with itemized actual costs for common distribution upgrades.	Oppose		*n/a - new*

Modifications proposed by the Company or other parties in Initial Comments are denoted in redline. Additional modifications we propose with these Reply Comments are denoted in blue redline format.

Requirement No.	Requirement	Position	Reply Comments	Justification from Initial Comments
JSC/CEF 3	Require Itemization on Reconciliation Statements: Direct Minnesota's utilities to provide interconnection customers with a detailed, itemized, clear statement of final costs for all distribution upgrades, including explanations for variances exceeding 125% of the original estimate.	Oppose	interconnections. Finally, providing this level of detail would be administratively burdensome, siphoning resources that would be better spent elsewhere. Parties have raised these types of recommendations in the past and the Commission has deemed them excessive, as discussed in our Reply Comments.	*n/a - new*
JSC/CEF 4	Require Acceptance of Both Letters of Credit and Bonds for Interconnection Deposits.	Oppose	As noted above regarding Requirement H.6, this is inconsistent with MN DIP. It is also inconsistent with the Company's credit policy as allowed under MN DIP. Bonds provide less certainty to the Company and would increase our costs. For example, the financial institution that has issued the bond can raise defenses to making payment. For example, they might argue that more detailed billing needs to be provided. This could necessitate litigation and associated expense to collect on the bond. This would be vesting with a court, instead of the Commission, the interpretation on how MN DIP should operate. Further, JSC/CEF argues that developers should not incur these costs until final billing. But, we are incurring costs well ahead of the final billing and should not be incurring carrying costs from the time the costs are incurred until the time for payment as proposed by JSC/CEF which may be well after our costs have been incurred. For these reasons, the JSC/CEF position should not be adopted.	*n/a - new*

Requirement No.	**Requirement**	**Position**	**Justification [No Change from Initial Comments]**
Dispute Resolution Process for the Distribution System Reactive Upgrade Process (DSRUP)			
For Disputes Between Interconnection Customers (and Developers) and the Public Utility			
Generally, follow the MN DIP process, except where shown in yellow highlight *italics* below:			
5.3	Disputes	*n/a - MN DIP*	
5.3.1	The Parties agree to attempt to resolve all disputes arising out of the interconnection process	*n/a - MN DIP*	
	(and the DSRUP)	Support	
	and associated study and Interconnection Agreements according to the provisions of this article and Minnesota Administrative Rules 7829.1500-7829.1900. More information on the Commission's Consumer Affairs Office dispute resolution services is available on the Commission's website: https://mn.gov/puc/consumers/help/complaint/	*n/a - MN DIP*	
5.3.2	Prior to a written Notice of Dispute, the Party shall contact the other Party and raise the issue and the relief sought in an attempt to resolve the issue immediately.	*n/a - MN DIP*	
5.3.3	In the event of a dispute, the disputing Party shall provide the other Party a written Notice of Dispute containing the relevant known facts pertaining to the dispute, the specific dispute and the relief sought, and express notice by the disputing Party that it is invoking the procedures under this article. The Interconnection Customer may utilize the Commission's Consumer Affairs Office's complaint/inquiry form and Informal Complaint dispute resolution process to assist with the written Notice of Dispute. The notice shall be sent to the non-disputing Party's email address and physical address set forth in the Interconnection Agreement or Interconnection Application, if there is no Interconnection Agreement. If the Interconnection Customer chooses not to utilize the Commission's Consumer Affair Office dispute resolution process, the Interconnection Customer shall provide an informational electronic copy of the Notice of Dispute to the Consumer Affairs Office at the Commission at consumer.puc@state.mn.us.	*n/a - MN DIP*	
	For Disputes relating to the DSRUP, it is mandatory to either complete the Commission's Consumer Affairs Office complaint/inquiry form or provide an informational copy to the CAO and this will provide notice to the Ombudsperson of the Dispute. For the first three years of DSRUP implementation, any Dispute regarding the DSRUP will not be logged as a complaint so that the Dispute will not count towards triggering service quality payments. Also, any Dispute relating to the DSRUP must be timely brought ("Timely Brought") in such a way so as to not further adversely impact other Interconnection Applications compared to if the Dispute had been brought in a timelier manner.	Oppose	
Xcel 5.3.3 part 2	*For Disputes relating to the DSRUP, it is mandatory to either complete the Commission's Consumer Affairs Office complaint/inquiry form or provide an informational copy to the CAO and this will provide notice to the Ombudsperson of the Dispute. ~~For the first three years of DSRUP implementation,~~ Any Dispute regarding the DSRUP will not be logged as a complaint so that the Dispute will not count towards triggering service quality payments. Also, any Dispute relating to the DSRUP must be timely brought ("Timely Brought") in such a way so as to not further adversely impact other Interconnection Applications compared to if the Dispute had been brought in a timelier manner.*	Support as modified	Any complaints should not count toward the Company's complaint threshold because DSRUP is a new process, required by law. DSRUP was not considered when the Company's complaint threshold or penalties were set, based on record development in a dedicated proceeding. Any changes to the Company's Quality of Service Plan tariff should be reviewed holistically in that docket.
5.3.4	The non-disputing Party shall acknowledge the notice within three (3) Business Days of its receipt and identify a representative with the authority to make decisions for the non-disputing Party with respect to the dispute.	*n/a - MN DIP*	
	For Disputes relating to the DSRUP, if resolution of the Dispute might have a material impact on any other Interconnection Application, then that impacted Interconnection Application may be placed on hold until the Dispute is resolved.	Support	
5.3.5	The non-disputing Party shall provide the disputing Party with relevant regulatory and/or technical details and analysis regarding the Area EPS Operator interconnection requirements under dispute within ten (10) Business Days of the date of the Notice of Dispute.	*n/a - MN DIP*	
	If the Area EPS Operator believes that one or more other Interconnection Customers would be materially impacted by the resolution of a Dispute relating DSRUP, then the Area EPS Operator may as part of the 10 Business Day response above make any such Interconnection Customer a Party to the Dispute, and may provide pertinent details about the dispute to any Party to the Dispute including but not limited to as to any Party's position in the queue, name of any Party to the Dispute, and any such Party's assigned feeder and substation, date application was Deemed Complete, nameplate capacity of the Interconnection Application, etc. and an explanation of how each Party may be materially impacted by the resolution of the Dispute.	Support	
	Within twenty (20) Business Days of the date of the Notice of Dispute, the Parties' authorized representatives will be required to meet and confer to try to resolve the dispute. Parties shall operate in good faith and use best efforts to resolve the dispute.	*n/a - MN DIP*	

Requirement No.	Requirement	Position	Justification [No Change from Initial Comments]
5.3.6	If a resolution is not reached in the thirty (30) Business Days from the date of the notice described in section 5.3.3, the Parties may 1) if mutually agreed, continue negotiations for up to an additional twenty (20) Business Days; or 2) either Party may request the Commission's Consumer Affairs Office provide mediation in an attempt to resolve the dispute within twenty (20) Business Days with the opportunity to extend this timeline upon mutual agreement. Alternatively, both Parties by mutual agreement may request mediation from an outside third-party mediator with costs to be shared equally between the Parties.	*n/a - MN DIP*	
	In the case of a Dispute relating to the DSRUP, any Party may bring dispute relating to Reactive Cost Sharing to the Ombudsperson at the Commission's CAO office for mediation.	Support	
5.3.7	If the results of the mediation are not accepted by one or more Parties (or by any Party for a Dispute in the case of a and there is still disagreement, the dispute shall proceed to the Commission's Formal Complaint process as described in Minn. Rules 7829.1700-1900 unless mutually agreed to continue with informal dispute resolution.	*n/a - MN DIP*	
5.3.8	At any time, either Party may file a complaint before the Commission pursuant to Minn. Stat. §216B.164, if applicable, and Commission rules outlined in Minn. Rules Ch. 7829.	*n/a - MN DIP*	
	Additional steps for Disputes relating to the DSRUP:		
	If the Dispute is not resolved following the above steps 5.3.1 to 5.3.6, then any Party may bring any Timely Brought Dispute relating to the DSRUP to the Commission for Expedited Dispute Resolution in the following way: File in a new Docket a Petition for Resolution of Dispute Relating to the DSRUP, include in that Petition all Parties to the Dispute as set forth above, and include in that Petition all pertinent facts. All Parties that are not Petitioners may be allowed 20 Business Days to submit their positions on the issue to the Commission, including where applicable a discussion on whether the Dispute has been Timely Brought. The Executive Secretary will determine if further rounds of comments are appropriate and will then set the matter for hearing. At hearing, the Commission may use its judgment on how the Dispute should be resolved, or whether further investigation is necessary. The Commission may determine whether the Dispute has not been Timely Brought and therefore is time barred.	*Support*	

CERTIFICATE OF SERVICE

I, Victor Barreiro, 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,E015,E017/CI-24-288

Dated this 19th day of November 2025

/s/
____
Victor Barreiro
Regulatory Administrator

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
1	Daniel	Abelson	daniel.abelson@metc.state.mn.us	Metropolitan Council		390 Robert Street N. St. Paul MN, 55101 United States	Electronic Service		No	24-288Official 24-288
2	Brian	Allen	brian.allen@allenergysolar.com	All Energy Solar, Inc		1642 Carroll Ave Saint Paul MN, 55104 United States	Electronic Service		No	24-288Official 24-288
3	Michael	Allen	michael.allen@allenergysolar.com	All Energy Solar		721 W 26th st Suite 211 Minneapolis MN, 55405 United States	Electronic Service		No	24-288Official 24-288
4	Ellen	Anderson	ellena@umn.edu	325 Learning and Environmental Sciences		1954 Buford Ave Saint Paul MN, 55108 United States	Electronic Service		No	24-288Official 24-288
5	Janet	Anderson	jcainstp@icloud.com	-		1799 Sargent St. Paul MN, 55105 United States	Electronic Service		No	24-288Official 24-288
6	Jay	Anderson	jaya@cmpas.org	CMPAS		7550 Corporate Way Suite 100 Eden Prairie MN, 55344 United States	Electronic Service		No	24-288Official 24-288
7	MK	Anderson	anderson@fresh-energy.org	Fresh Energy		408 St Peter Street Saint Paul MN, 55102 United States	Electronic Service		No	24-288Official 24-288
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10	John	Bailey	bailey@ilsr.org	Institute For Local Self-Reliance		1313 5th St SE Ste 303 Minneapolis MN, 55414 United States	Electronic Service		No	24-288Official 24-288
11	Anjali	Bains	bains@fresh-energy.org	Fresh Energy		408 Saint Peter Ste 220 Saint Paul MN, 55102 United States	Electronic Service		No	24-288Official 24-288
12	Mark	Bakk	mbakk@lcp.coop	Lake Country Power		26039 Bear Ridge Drive Cohasset MN, 55721 United States	Electronic Service		No	24-288Official 24-288
13	Jared	Ballew	jared.ballew@ev.energy	EV.ENERGY CORP		726 18th St. Des Moines IA, 50314 United States	Electronic Service		No	24-288Official 24-288
14	Laura	Beaton	beaton@smwlaw.com	Shute, Mihaly & Weinberger LLP		396 Hayes Street San Francisco CA, 94102 United States	Electronic Service		No	24-288Official 24-288
15	Mathias	Bell	mathias@weavegrid.com	WeaveGrid		375 Alabama Street, Suite 325 San Francisco CA, 94110 United States	Electronic Service		No	24-288Official 24-288

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16	Jeff	Benson	jbenson@southcentralelectric.com	South Central Electric Association		PO Box 150 71176 Tiell Drive St. James MN, 56081 United States	Electronic Service		No	24-288Official 24-288
17	Sasha	Bergman	sasha.bergman@state.mn.us		Public Utilities Commission		Electronic Service		No	24-288Official 24-288
18	Derek	Bertsch	derek.bertsch@mrenergy.com	Missouri River Energy Services		3724 West Avera Drive PO Box 88920 Sioux Falls SD, 57109-8920 United States	Electronic Service		No	24-288Official 24-288
19	Barb	Bischoff	barb.bischoff@nngco.com	Northern Natural Gas Co.		CORP HQ, 714 1111 So. 103rd Street Omaha NE, 68124-1000 United States	Electronic Service		No	24-288Official 24-288
20	Ingrid	Bjorklund	ibjorklund@avisenlegal.com	Avisen Legal		901 S. Marquette Ave. #1675 Minneapolis MN, 55402 United States	Electronic Service		No	24-288Official 24-288
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22	William	Black	bblack@mmua.org	MMUA		Suite 200 3131 Fernbrook Lane North Plymouth MN, 55447 United States	Electronic Service		No	24-288Official 24-288
23	Nick	Bowman	nick@communitysolaraccess.org	CCSA		1380 Monroe Street NW #721 Washington DC, 20010 United States	Electronic Service		No	24-288Official 24-288
24	Kenneth	Bradley	kbradley@environmentminnesota.org			2837 Emerson Ave S Apt CW112 Minneapolis MN, 55408 United States	Electronic Service		No	24-288Official 24-288
25	Jon	Brekke	jbrekke@grenergy.com	Great River Energy		12300 Elm Creek Boulevard Maple Grove MN, 55369-4718 United States	Electronic Service		No	24-288Official 24-288
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27	Sydney R.	Briggs	sbriggs@swce.coop	Steele-Waseca Cooperative Electric		2411 W. Bridge St PO Box 485 Owatonna MN, 55060-0485 United States	Electronic Service		No	24-288Official 24-288
28	Mark B.	Bring	mbring@otpco.com	Otter Tail Power Company		215 South Cascade Street PO Box 496 Fergus Falls MN, 56538-	Electronic Service		No	24-288Official 24-288

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
						0496 United States				
29	Matthew	Brodin	mbrodin@allete.com	Minnesota Power		30 West Superior Street Duluth MN, 55802 United States	Electronic Service		No	24-288Official 24-288
30	Christopher	Browning	christopher.browning@nexteraenergy.com			null null, null United States	Electronic Service		No	24-288Official 24-288
31	Christina	Brusven	cbrusven@fredlaw.com	Fredrikson Byron		60 S 6th St Ste 1500 Minneapolis MN, 55402-4400 United States	Electronic Service		No	24-288Official 24-288
32	Mike	Bull	mike.bull@state.mn.us		Public Utilities Commission	121 7th Place East, Suite 350 St. Paul MN, 55101 United States	Electronic Service		Yes	24-288Official 24-288
33	Jessica	Burdette	jessica.burdette@state.mn.us		Department of Commerce	85 7th Place East Suite 500 St. Paul MN, 55101 United States	Electronic Service		No	24-288Official 24-288
34	Jerry	Byer	jbyer@itasca-mantrap.com	Itasca-Mantrap Coop. Electrical Ass'n		PO Box 192 Park Rapids MN, 56470 United States	Electronic Service		No	24-288Official 24-288
35	Jennifer	Cady	jjcady@mnpower.com	Minnesota Power		30 W Superior St Duluth MN, 55802 United States	Electronic Service		No	24-288Official 24-288
36	Daniel T	Carlisle	todd-wad@toddwadena.coop	Todd-Wadena Electric Cooperative		550 Ash Ave NE PO Box 431 Wadena MN, 56482 United States	Electronic Service		No	24-288Official 24-288
37	Douglas M.	Carnival	dcarnival@carnivalberns.com	McGrann Shea Carnival Straughn & Lamb		800 Nicollet Mall Ste 2600 Minneapolis MN, 55402-7035 United States	Electronic Service		No	24-288Official 24-288
38	Pat	Carruth	pat@mnvalleyrec.com	Minnesota Valley Coop. Light & Power Assn.		501 S 1st St. PO Box 248 Montevideo MN, 56265 United States	Electronic Service		No	24-288Official 24-288
39	Gabriel	Chan	gabechan@umn.edu			130 Hubert H. Humphrey Center 301 19th Ave S Minneapolis MN, 55455 United States	Electronic Service		No	24-288Official 24-288
40	Ray	Choquette	rchoquette@agp.com	Ag Processing Inc.		12700 West Dodge Road PO Box 2047 Omaha NE, 68103-2047 United States	Electronic Service		No	24-288Official 24-288
41	City	Clerk	gregg.engdahl@ci.stcloud.mn.us	City of St. Cloud		400 Second St. S St. Cloud MN, 56301 United States	Electronic Service		No	24-288Official 24-288
42	Joshua	Cohen	josh.cohen@swtchenergy.com	SWTCH Energy, Inc.		Greentown Labs 444 Somerville Avenue	Electronic Service		No	24-288Official 24-288

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
						Somerville MA, 02143 United States				
43	Kenneth A.	Colburn	kcolburn@symbioticstrategies.com	Symbiotic Strategies, LLC		26 Winton Road Meredith NH, 32535413 United States	Electronic Service		No	24-288Official 24-288
44	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	24-288Official 24-288
45	Kevin	Cray	kevin@communitysolaraccess.org	CCSA		1644 Platte St Denver CO, 80202 United States	Electronic Service		No	24-288Official 24-288
46	George	Crocker	gwillc@nawo.org	North American Water Office		5093 Keats Avenue Lake Elmo MN, 55042 United States	Electronic Service		No	24-288Official 24-288
47	Stacy	Dahl	sdahl@minnkota.com	Minnkota Power Cooperative, Inc.		5301 32nd Ave S Grand Forks ND, 58201 United States	Electronic Service		No	24-288Official 24-288
48	George	Damian	gdamian@cleanenergyeconomymn.org	Clean Energy Economy MN		13713 Washburn Ave S Burnsville MN, 55337 United States	Electronic Service		No	24-288Official 24-288
49	Lisa	Daniels	lisadaniels@windustry.org	Windustry		201 Ridgewood Ave Minneapolis MN, 55403 United States	Electronic Service		No	24-288Official 24-288
50	James	Darabi	james.darabi@solarfarm.com			2355 Fairview Ave #101 St. Paul MN, 55113 United States	Electronic Service		No	24-288Official 24-288
51	Danielle	DeMarre	danielle.demarre@allenergysolar.com	All Energy Solar		1264 Energy Lane St Paul MN, 55108 United States	Electronic Service		No	24-288Official 24-288
52	Timothy	DenHerder Thomas	timothy@cooperativeenergyfutures.com	Cooperative Energy Futures		3500 Bloomington Ave. S Minneapolis MN, 55407 United States	Electronic Service		No	24-288Official 24-288
53	James	Denniston	james.r.denniston@xcelenergy.com	Xcel Energy Services, Inc.		414 Nicollet Mall, 401-8 Minneapolis MN, 55401 United States	Electronic Service		No	24-288Official 24-288
54	Curt	Dieren	curt.dieren@dgr.com	L&O Power Cooperative		1302 S Union St Rock Rapids IA, 51246 United States	Electronic Service		No	24-288Official 24-288
55	Cheryl	Dietrich	cheryl.dietrich@nexteraenergy.com	NextEra Energy Resources, LLC		700 Universe Blvd E1W/JB Juno Beach FL, 33408 United States	Electronic Service		No	24-288Official 24-288
56	Ian M.	Dobson	ian.m.dobson@xcelenergy.com	Xcel Energy		414 Nicollet Mall, 401-8 Minneapolis MN, 55401 United States	Electronic Service		No	24-288Official 24-288
57	Kristin	Dolan	kdolan@meeker.coop	Meeker Cooperative		1725 US Hwy 12 E. Ste 100	Electronic Service		No	24-288Official

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58	Renee	Doyle	guydoyleelectric@gmail.com	Doyle Electric Inc.		PO Box 295 Amboy MN, 56010 United States	Electronic Service		No	24-288Official 24-288
59	Carlon	Doyle Fontaine	carlon.doyle.fontaine@senate.mn	MN Senate		75 Rev Dr Martin Luther King Jr Blvd Room G-17 St Paul MN, 55155 United States	Electronic Service		No	24-288Official 24-288
60	Adam	Duininck	aduininck@ncsrcc.org	North Central States Regional Council of Carpenters		700 Olive Street St. Paul MN, 55130 United States	Electronic Service		No	24-288Official 24-288
61	Scott	Dunbar	sdunbar@kfwlaw.com	Keyes & Fox LLP		1580 Lincoln St Ste 880 Denver CO, 80203 United States	Electronic Service		No	24-288Official 24-288
62	John R.	Dunlop, P.E.	jdunlop@resminn.com	Renewable Energy Services		Suite 300 448 Morgan Ave. S. Minneapolis MN, 55405-2030 United States	Electronic Service		No	24-288Official 24-288
63	Hannah	Dunn	hannah.dunn@oakdalemn.gov	City of Oakdale		1584 Hadley Ave N Oakdale MN, 55104 United States	Electronic Service		No	24-288Official 24-288
64	Kelly	Dybdahl	kdybdahl@llec.coop	Lyon-Lincoln Electric Cooperative, Inc.		205 W. Hwy. 14 Tyler MN, 56178 United States	Electronic Service		No	24-288Official 24-288
65	Brian	Edstrom	briane@cubminnesota.org	Citizens Utility Board of Minnesota		332 Minnesota St Ste W1360 Saint Paul MN, 55101 United States	Electronic Service		No	24-288Official 24-288
66	Dick	Edwards	dedwards@ci.maple-grove.mn.us	City of Maple Grove		12800 Arbor Lakes Parkway P O Box 1180 Maple Grove MN, 55311-6180 United States	Electronic Service		No	24-288Official 24-288
67	William	Ehrlich	wehrlich@tesla.com	Tesla, Inc.		3500 Deer Creek Rd Palo Alto CA, 94304 United States	Electronic Service		No	24-288Official 24-288
68	Kristen	Eide Tollefson	healingsystems69@gmail.com	R-CURE		28477 N Lake Ave Frontenac MN, 55026-1044 United States	Electronic Service		No	24-288Official 24-288
69	Bob	Eleff	bob.eleff@house.mn	Regulated Industries Cmte		100 Rev Dr Martin Luther King Jr Blvd Room 600 St. Paul MN, 55155 United States	Electronic Service		No	24-288Official 24-288
70	R. Neal	Elliot	rnelliott@aceee.org	American Council for an Energy-Efficient Economy		ACEEE 529 14th St NW Ste 600 Washington DC, 20045 United States	Electronic Service		No	24-288Official 24-288

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
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72	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	24-288Official 24-288
73	Christian	Fenstermacher	christian.fenstermacher@owatonnautilities.com	Owatonna Municipal Public Utilities		PO Box 800 208 S Walnut Ave Owatonna MN, 55060 United States	Electronic Service		No	24-288Official 24-288
74	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	24-288Official 24-288
75	Christine	Fox	cfox@itasca-mantrap.com	Itasca-Mantrap Coop. Electric Assn.		PO Box 192 Park Rapids MN, 56470 United States	Electronic Service		No	24-288Official 24-288
76	Kornbaum	Frank	fkornbaum@mnpower.com			null null, null United States	Electronic Service		No	24-288Official 24-288
77	Nathan	Franzen	nathan@nationalgridrenewables.com	Geronimo Energy, LLC		8400 Normandale Lake Blvd Ste 1200 Bloomington MN, 55437 United States	Electronic Service		No	24-288Official 24-288
78	David	Freestate	dfreestate@epri.com	EPRI		942 Corridor Park Blvd Knoxville TN, 37932 United States	Electronic Service		No	24-288Official 24-288
79	Katelyn	Frye	kfrye@mnpower.com	Minnesota Power		30 W Superiot St Duluth MN, 55802-2093 United States	Electronic Service		No	24-288Official 24-288
80	Jessica	Fyhrie	jfyhrie@otpco.com	Otter Tail Power Company		PO Box 496 Fergus Falls MN, 56538-0496 United States	Electronic Service		No	24-288Official 24-288
81	Edward	Garvey	garveyed@aol.com	Residence		32 Lawton St Saint Paul MN, 55102 United States	Electronic Service		No	24-288Official 24-288
82	Allen	Gleckner	gleckner@fresh-energy.org	Fresh Energy		408 St. Peter Street Ste 350 Saint Paul MN, 55102 United States	Electronic Service		No	24-288Official 24-288
83	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	24-288Official 24-288
84	Jenny	Glumack	jenny@mrea.org	Minnesota Rural Electric Association		11640 73rd Ave N Maple Grove MN, 55369 United States	Electronic Service		No	24-288Official 24-288
85	Sean	Gosiewski	sean@afors.org	Alliance for Sustainability		2801 21st Ave S Ste 100 Minneapolis	Electronic Service		No	24-288Official 24-288

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
						MN, 55407 United States				
86	Scott	Greenbert	scott@nautilussolar.com	Nautilus Solar Energy, LLC		396 Springfield Aver, Ste 2 Summit NJ, 07901 United States	Electronic Service		No	24-288Official 24-288
87	Sarah	Groebner	sgroebner@redwoodelectric.com	Redwood Electric Cooperative		60 Pine St Clements MN, 56224 United States	Electronic Service		No	24-288Official 24-288
88	Tim	Gross	tgross@fuelingmn.com	Fueling Minnesota		3244 Rice Street St. Paul MN, 55126 United States	Electronic Service		No	24-288Official 24-288
89	Cody	Gustafson	cgustafson@mnpower.com			null null, null United States	Electronic Service		No	24-288Official 24-288
90	Tom	Guttormson	tom.guttormson@connexusenergy.com	Connexus Energy		14601 Ramsey Blvd Ramsey MN, 55303 United States	Electronic Service		No	24-288Official 24-288
91	Natalie	Haberman	townsend@fresh-energy.org	Fresh Energy		408 St Peter St # 350 St. Paul MN, 55102 United States	Electronic Service		No	24-288Official 24-288
92	James	Haler	jhaler@southcentralelectric.com	South Central Electric Association		71176 Tiell Dr P. O. Box 150 St. James MN, 56081 United States	Electronic Service		No	24-288Official 24-288
93	Joe	Halso	joe.halso@sierraclub.org	Sierra Club		1536 Wynkoop St Ste 200 Denver CO, 80202 United States	Electronic Service		No	24-288Official 24-288
94	Donald	Hanson	dfhanson@ieee.org			P. O. Box 44579 Eden Prairie MN, 55344 United States	Electronic Service		No	24-288Official 24-288
95	John	Harlander	john.c.harlander@xcelenergy.com	Xcel Energy		null null, null United States	Electronic Service		No	24-288Official 24-288
96	Kim	Havey	kim.havey@minneapolismn.gov	City of Minneapolis		350 South 5th Street, Suite 315M Minneapolis MN, 55415 United States	Electronic Service		No	24-288Official 24-288
97	Todd	Headlee	theadlee@dvigridsolutions.com	Dominion Voltage, Inc.		701 E. Cary Street Richmond VA, 23219 United States	Electronic Service		No	24-288Official 24-288
98	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	24-288Official 24-288
99	Tiana	Heger	theger@mnpower.com	Minnesota Power		30 W. Superior Street Duluth MN, 55802 United States	Electronic Service		No	24-288Official 24-288
100	Adam	Heinen	aheinen@dakotaelectric.com	Dakota Electric Association		4300 220th St W Farmington MN, 55024 United States	Electronic Service		No	24-288Official 24-288
101	Annete	Henkel	mui@mnutilityinvestors.org	Minnesota Utility Investors		413 Wacouta Street	Electronic Service		No	24-288Official

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
						#230 St.Paul MN, 55101 United States				24-288
102	Jessy	Hennesy	jessy.hennesy@avantenergy.com	Avant Energy		220 S. Sixth St. Ste 1300 Minneapolis MN, 55402 United States	Electronic Service		No	24-288Official 24-288
103	Joe	Hoffman	ja.hoffman@smmpa.org	SMMPA		500 First Ave SW Rochester MN, 55902-3303 United States	Electronic Service		No	24-288Official 24-288
104	Michael	Hoppe	lu23@ibew23.org	Local Union 23, I.B.E.W.		445 Etna Street Ste. 61 St. Paul MN, 55106 United States	Electronic Service		No	24-288Official 24-288
105	Ronald	Horman	rhorman@redwoodelectric.com	Redwood Electric Cooperative		60 Pine Street Clements MN, 56224 United States	Electronic Service		No	24-288Official 24-288
106	Samantha	Houston	shouston@ucsusa.org	Union of Concerned Scientists		1825 K St. NW Ste 800 Washington DC, 20006 United States	Electronic Service		No	24-288Official 24-288
107	Lori	Hoyum	lhoyum@mnpower.com	Minnesota Power		30 West Superior Street Duluth MN, 55802 United States	Electronic Service		No	24-288Official 24-288
108	Jan	Hubbard	jan.hubbard@comcast.net			7730 Mississippi Lane Brooklyn Park MN, 55444 United States	Electronic Service		No	24-288Official 24-288
109	Dean	Hunter	dean.hunter@state.mn.us		Minnesota Department of Labor & Industry	443 Lafayette Rd N St. Paul MN, 55155-4341 United States	Electronic Service		No	24-288Official 24-288
110	Reuben	Hunter	bhunter@madisonei.com	Madison Energy Investments		8100 Boone Blvd Suite 430 Vienna VA, 22182 United States	Electronic Service		No	24-288Official 24-288
111	Casey	Jacobson	cjacobson@bepc.com	Basin Electric Power Cooperative		1717 East Interstate Avenue Bismarck ND, 58501 United States	Electronic Service		No	24-288Official 24-288
112	John S.	Jaffray	jjaffray@jjrpower.com	JJR Power		350 Highway 7 Suite 236 Excelsior MN, 55331 United States	Electronic Service		No	24-288Official 24-288
113	Robert	Jagusch	rjagusch@mmua.org	MMUA		3025 Harbor Lane N Minneapolis MN, 55447 United States	Electronic Service		No	24-288Official 24-288
114	Chris	Jarosch	chris@carrcreekelectricservice.com	Carr Creek Electric Service, LLC		209 Sommers Street North Hudson WI, 54016 United States	Electronic Service		No	24-288Official 24-288
115	Alan	Jenkins	aj@jenkinsatlaw.com	Jenkins at Law		2950 Yellowtail Ave. Marathon FL, 33050 United States	Electronic Service		No	24-288Official 24-288

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
116	Richard	Johnson	rick.johnson@lawmoss.com	Moss & Barnett		150 S. 5th Street Suite 1200 Minneapolis MN, 55402 United States	Electronic Service		No	24-288Official 24-288
117	Sarah	Johnson Phillips	sjphillips@stoel.com	Stoel Rives LLP		33 South Sixth Street Suite 4200 Minneapolis MN, 55402 United States	Electronic Service		No	24-288Official 24-288
118	Nate	Jones	njones@hcpd.com	Heartland Consumers Power		PO Box 248 Madison SD, 57042 United States	Electronic Service		No	24-288Official 24-288
119	Philip	Jones	phil@evtransportationalliance.org			1402 Third Ave Ste 1315 Seattle WA, 98101 United States	Electronic Service		No	24-288Official 24-288
120	Julie	Jorgensen	julie@greenmark.us.com	Greenmark Solar		4630 Quebec Ave N New Hope MN, 55428-4973 United States	Electronic Service		No	24-288Official 24-288
121	Kevin	Joyce	kjoyce@tesla.com			null null, null United States	Electronic Service		No	24-288Official 24-288
122	Mahmoud	Kabalan	mahmoud.kabalan@stthomas.edu	University of St Thomas		2115 Summit Ave. Mail OSS100 School of Engineering Saint Paul MN, 55105 United States	Electronic Service		No	24-288Official 24-288
123	Camille	Kadoch	ckadoch@raponline.org	Regulatory Assistance Project		50 State Street Suite 3 Montpelier VT, 05602 United States	Electronic Service		No	24-288Official 24-288
124	Cliff	Kaehler	cliff.kaehler@novelenergy.biz	Novel Energy Solutions LLC		4710 Blaylock Way Inver Grove Heights MN, 55076 United States	Electronic Service		No	24-288Official 24-288
125	Ralph	Kaehler	ralph.kaehler@gmail.com			13700 Co. Rd. 9 Eyota MN, 55934 United States	Electronic Service		No	24-288Official 24-288
126	Michael	Kampmeyer	mkampmeyer@a-e-group.com	AEG Group, LLC		260 Salem Church Road Sunfish Lake MN, 55118 United States	Electronic Service		No	24-288Official 24-288
127	Nick	Kaneski	nick.kaneski@enbridge.com	Enbridge Energy Company, Inc.		11 East Superior St Ste 125 Duluth MN, 55802 United States	Electronic Service		No	24-288Official 24-288
128	Jack	Kegel	jkegel@mmua.org	MMUA		3025 Harbor Lane N Suite 400 Plymouth MN, 55447-5142 United States	Electronic Service		No	24-288Official 24-288
129	William	Kenworthy	will@votesolar.org			1 South Dearborn St Ste 2000 Chicago IL, 60603 United States	Electronic Service		No	24-288Official 24-288
130	Samuel B.	Ketchum	sketchum@kennedy-graven.com	Kennedy & Graven,		150 S 5th St Ste 700	Electronic Service		No	24-288Official

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
				Chartered		Minneapolis MN, 55402 United States				24-288
131	Tom	Key	tkey@epri.com	EPRI		942 Corridor Park Blvd Knoxville TN, 37932 United States	Electronic Service		No	24-288Official 24-288
132	Bobby	King	bking@solarunitedneighbors.org	Solar United Neighbors		3140 43rd Ave S Minneapolis MN, 55406 United States	Electronic Service		No	24-288Official 24-288
133	Jack	Kluempke	jack.kluempke@state.mn.us		Department of Commerce	85 7th Place East Suite 600 St. Paul MN, 55101 United States	Electronic Service		No	24-288Official 24-288
134	Aaron	Knoll	aknoll@greeneespel.com	Greene Espel PLLP		222 South Ninth Street Suite 2200 Minneapolis MN, 55402 United States	Electronic Service		No	24-288Official 24-288
135	Steve	Kosbab	skosbab@meeker.coop	Meeker Cooperative Light and Power		1725 US Hwy 12 E Litchfield MN, 55355 United States	Electronic Service		No	24-288Official 24-288
136	Brian	Krambeer	bkrambeer@mienergy.coop	MiEnergy Cooperative		PO Box 626 31110 Cooperative Way Rushford MN, 55971 United States	Electronic Service		No	24-288Official 24-288
137	Michael	Krause	michaelkrause61@yahoo.com			1200 Plymouth Avenue Minneapolis MN, 55411 United States	Electronic Service		No	24-288Official 24-288
138	Michael	Krikava	mkrikava@taftlaw.com	Taft Stettinius & Hollister LLP		2200 IDS Center 80 S 8th St Minneapolis MN, 55402 United States	Electronic Service		No	24-288Official 24-288
139	Corrina	Kumpe	ckumpe@mysunshare.com			null null, null United States	Electronic Service		No	24-288Official 24-288
140	Matthew	Lacey	mlacey@grenergy.com	Great River Energy		12300 Elm Creek Boulevard Maple Grove MN, 55369-4718 United States	Electronic Service		No	24-288Official 24-288
141	James D.	Larson	james.larson@avantenergy.com	Avant Energy Services		220 S 6th St Ste 1300 Minneapolis MN, 55402 United States	Electronic Service		No	24-288Official 24-288
142	Mark	Larson	mlarson@meeker.coop	Meeker Coop Light & Power Assn		1725 Highway 12 E Ste 100 Litchfield MN, 55355 United States	Electronic Service		No	24-288Official 24-288
143	Burnell	Lauer	blauer.sundial@gmail.com	Sundial Solar		3209 W. 76th St #305 Edina MN, 55435 United States	Electronic Service		No	24-288Official 24-288
144	Dean	Leischow	dean@sunrisenrg.com	Sunrise Energy Ventures		315 Manitoba Ave Ste 200 Wayzata MN, 55391 United States	Electronic Service		No	24-288Official 24-288

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
145	Annie	Levenson Falk	annielf@cubminnesota.org	Citizens Utility Board of Minnesota		332 Minnesota Street, Suite W1360 St. Paul MN, 55101 United States	Electronic Service		No	24-288Official 24-288
146	Benjamin	Levine	blevine@mnpower.com	Minnesota Power		30 West Superior Street Duluth MN, 55802 United States	Electronic Service		No	24-288Official 24-288
147	Amy	Liberkowski	amy.a.liberkowski@xcelenergy.com	Xcel Energy		414 Nicollet Mall 7th Floor Minneapolis MN, 55401-1993 United States	Electronic Service		No	24-288Official 24-288
148	Carl	Linvill	clinvill@raponline.org			50 State Street Suite #3 Montpelier VT, 05602 United States	Electronic Service		No	24-288Official 24-288
149	Phillip	Lipetsky	greenenergyproductsllc@gmail.com	Green Energy Products		PO Box 108 Springfield MN, 56087 United States	Electronic Service		No	24-288Official 24-288
150	Jody	Londo	jody.l.londo@xcelenergy.com	Xcel Energy		414 Nicillet Mall 7th Floor Minneapolis MN, 55401-1993 United States	Electronic Service		No	24-288Official 24-288
151	Susan	Ludwig	sludwig@mnpower.com	Minnesota Power		30 West Superior Street Duluth MN, 55802 United States	Electronic Service		No	24-288Official 24-288
152	Brian	Lydic	brian@irecusa.org	Interstate Renewable Energy Council, Inc.		PO Box 1156 Latham NY, 12110-1156 United States	Electronic Service		No	24-288Official 24-288
153	Richard	Macke	macker@powersystem.org	Power System Engineering, Inc.		10710 Town Square Dr NE Ste 201 Minneapolis MN, 55449 United States	Electronic Service		No	24-288Official 24-288
154	Alice	Madden	alice@communitypowermn.org	Community Power		2720 E 22nd St Minneapolis MN, 55406 United States	Electronic Service		No	24-288Official 24-288
155	Alex	Magerko	amagerko@epri.com	EPRI		942 Corridor Park Blvd Knoxville TN, 37932 United States	Electronic Service		No	24-288Official 24-288
156	Kavita	Maini	kmaini@wi.rr.com	KM Energy Consulting, LLC		961 N Lost Woods Rd Oconomowoc WI, 53066 United States	Electronic Service		No	24-288Official 24-288
157	Discovery	Manager	discoverymanager@mnpower.com	Minnesota Power		30 W Superior St Duluth MN, 55802 United States	Electronic Service		No	24-288Official 24-288
158	Christine	Marquis	regulatory.records@xcelenergy.com	Xcel Energy		414 Nicollet Mall MN1180-07-MCA Minneapolis MN, 55401 United States	Electronic Service		No	24-288Official 24-288

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
159	Gregg	Mast	gmast@cleanenergyeconomymn.org	Clean Energy Economy Minnesota		4808 10th Avenue S Minneapolis MN, 55417 United States	Electronic Service		No	24-288Official 24-288
160	Jason	Maur	jason.maur@renesolapower.com	Renesola Power Holdings, LLC		850 Canal Street 3rd Floor Stamford CT, 06902 United States	Electronic Service		No	24-288Official 24-288
161	Erica	McConnell	emcconnell@elpc.org	Environmental Law & Policy Center		35 E. Wacker Drive, Suite 1600 Chicago IL, 60601 United States	Electronic Service		No	24-288Official 24-288
162	Jess	McCullough	jmccullough@mnpower.com	Minnesota Power		30 W Superior St Duluth MN, 55802 United States	Electronic Service		No	24-288Official 24-288
163	Sara G	McGrane	smcgrane@felhaber.com	Felhaber Larson		220 S 6th St Ste 2200 Minneapolis MN, 55420 United States	Electronic Service		No	24-288Official 24-288
164	Natalie	McIntire	natalie.mcintire@gmail.com	Wind on the Wires		570 Asbury St Ste 201 Saint Paul MN, 55104-1850 United States	Electronic Service		No	24-288Official 24-288
165	Matthew	Melewski	matthew@theboutiquefirm.com	Nokomis Energy LLC & Ole Solar LLC		2639 Nicollet Ave Ste 200 Minneapolis MN, 55408 United States	Electronic Service		No	24-288Official 24-288
166	Thomas	Melone	thomas.melone@allcous.com	Minnesota Go Solar LLC		222 South 9th Street Suite 1600 Minneapolis MN, 55120 United States	Electronic Service		No	24-288Official 24-288
167	Michael	Menzel	mike.m@sagiliti.com	Sagiliti		23505 Smithtown Rd. Suite 280 Excelsior MN, 55331 United States	Electronic Service		No	24-288Official 24-288
168	Tim	Mergen	tmergen@meeker.coop	Meeker Cooperative Light And Power		1725 US Hwy 12 E. Suite 100 PO Box 68 Litchfield MN, 55355 United States	Electronic Service		No	24-288Official 24-288
169	Pontius	Mike	mpontius@mnpower.com			null null, null United States	Electronic Service		No	24-288Official 24-288
170	Brian	Millberg	fwengineering@comcast.net			695 Grand AVe #222 Saint Paul MN, 55105 United States	Electronic Service		No	24-288Official 24-288
171	Luther	Miller	luther.c.miller@xcelenergy.com	Xcel Energy		null null, null United States	Electronic Service		No	24-288Official 24-288
172	Marc	Miller	mmiller@soltage.com	Soltage, LLC		66 York Street, 5th Floor Jersey City NJ, 07302 United States	Electronic Service		No	24-288Official 24-288
173	Stacy	Miller	stacy.miller@minneapolismn.gov	City of Minneapolis		350 S. 5th Street Room M 301	Electronic Service		No	24-288Official 24-288

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
						Minneapolis MN, 55415 United States				
174	Marcus	Mills	marcus@communitypowermn.org	Community Power		2720 E 22nd St Minneapolis MN, 55406 United States	Electronic Service		No	24-288Official 24-288
175	Darrick	Moe	darrick@mrea.org	Minnesota Rural Electric Association		11640 73rd Ave N Maple Grove MN, 55369 United States	Electronic Service		No	24-288Official 24-288
176	David	Moeller	dmoeller@allete.com	Minnesota Power			Electronic Service		No	24-288Official 24-288
177	Dalene	Monsebroten	dalene.monsebroten@nmpagency.com	Northern Municipal Power Agency		123 2nd St W Thief River Falls MN, 56701 United States	Electronic Service		No	24-288Official 24-288
178	Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP		33 South Sixth St Ste 4200 Minneapolis MN, 55402 United States	Electronic Service		No	24-288Official 24-288
179	Susan	Mudd	smudd@elpc.org	Environmental Law and Policy Center		35 E. Wacker Drive, Suite 1600 Chicago IL, 60601 United States	Electronic Service		No	24-288Official 24-288
180	Pouya	Najmaie	najm0001@gmail.com	Cooperative Energy Futures		3416 16th Ave S Minneapolis MN, 55407 United States	Electronic Service		No	24-288Official 24-288
181	Alex	Nelson	anelson@dakotaelectric.com	Dakota Electric Association		4300 220nd St Farmington MN, 55024 United States	Electronic Service		No	24-288Official 24-288
182	Anthony	Nelson	amnelson@otpco.com	Ottertail Power		53233 Sunrise Ln Park Rapids MN, 56470 United States	Electronic Service		No	24-288Official 24-288
183	Ben	Nelson	benn@cmpasgroup.org	CMMPA		459 South Grove Street Blue Earth MN, 56013 United States	Electronic Service		No	24-288Official 24-288
184	Carl	Nelson	cnelson@mncee.org	Center for Energy and Environment		212 3rd Ave N Ste 560 Minneapolis MN, 55401 United States	Electronic Service		No	24-288Official 24-288
185	Darin	Nelson	dnelson@minnetonkamn.gov	City of Minnetonka		14600 Minnetonka Blvd Minnetonka MN, 55345 United States	Electronic Service		No	24-288Official 24-288
186	David	Niles	david.niles@avantenergy.com	Minnesota Municipal Power Agency		220 South Sixth Street Suite 1300 Minneapolis MN, 55402 United States	Electronic Service		No	24-288Official 24-288
187	Sephra	Ninow	sephra.ninow@energycenter.org	Center for Sustainable Energy		426 17th Street, Suite 700 Oakland CA, 94612 United States	Electronic Service		No	24-288Official 24-288
188	Michael	Noble	noble@fresh-energy.org	Fresh Energy		408 Saint Peter St Ste 350	Electronic Service		No	24-288Official 24-288

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
						Saint Paul MN, 55102 United States				
189	Rolf	Nordstrom	rnordstrom@gpisd.net	Great Plains Institute		2801 21ST AVE S STE 220 Minneapolis MN, 55407-1229 United States	Electronic Service		No	24-288Official 24-288
190	Samantha	Norris	samanthanorris@alliantenergy.com	Interstate Power and Light Company		200 1st Street SE PO Box 351 Cedar Rapids IA, 52406-0351 United States	Electronic Service		No	24-288Official 24-288
191	David	O'Brien	david.obrien@navigant.com	Navigant Consulting		77 South Bedford St Ste 400 Burlington MA, 01803 United States	Electronic Service		No	24-288Official 24-288
192	Logan	O'Grady	logrady@mnseia.org	Minnesota Solar Energy Industries Association		2288 University Ave W St. Paul MN, 55114 United States	Electronic Service		No	24-288Official 24-288
193	Patty	O'Keefe	patty.okeefe@sierraclub.org			2525 Emerson Ave S Apt 2 Minneapolis MN, 55405 United States	Electronic Service		No	24-288Official 24-288
194	Timothy	O'Leary	toleary@llec.coop	Lyon-Lincoln Electric Cooperative, Inc		P.O. Box 639 Tyler MN, 56178-0639 United States	Electronic Service		No	24-288Official 24-288
195	Jeff	O'Neill	jeff.oneill@ci.monticello.mn.us	City of Monticello		505 Walnut Street Suite 1 Monticelllo MN, 55362 United States	Electronic Service		No	24-288Official 24-288
196	Matthew	Olsen	molsen@otpco.com	Otter Tail Power Company		215 South Cascade Street Fergus Falls MN, 56537 United States	Electronic Service		No	24-288Official 24-288
197	Russell	Olson	rolson@hcpd.com	Heartland Consumers Power District		PO Box 248 Madison SD, 57042-0248 United States	Electronic Service		No	24-288Official 24-288
198	Wendi	Olson	wolson@otpco.com	Otter Tail Power Company		215 South Cascade Fergus Falls MN, 56537 United States	Electronic Service		No	24-288Official 24-288
199	Carol A.	Overland	overland@legalectric.org	Legalectric - Overland Law Office		1110 West Avenue Red Wing MN, 55066 United States	Electronic Service		No	24-288Official 24-288
200	Bethany	Owen	bowen@mnpower.com	Minnesota Power		30 West Superior Street Duluth MN, 55802 United States	Electronic Service		No	24-288Official 24-288
201	Cezar	Panait	cezar.panait@state.mn.us		Public Utilities Commission	121 7th Place East Suite 350 St. Paul MN, 55101 United States	Electronic Service		No	24-288Official 24-288

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
202	Dan	Patry	dpatry@sunedison.com	SunEdison		600 Clipper Drive Belmont CA, 94002 United States	Electronic Service		No	24-288Official 24-288
203	Jeffrey C	Paulson	jeff.jcplaw@comcast.net	Paulson Law Office, Ltd.		4445 W 77th Street Suite 224 Edina MN, 55435 United States	Electronic Service		No	24-288Official 24-288
204	Dean	Pawlowski	dpawlowski@otpco.com	Otter Tail Power Company		PO Box 496 215 S. Cascade St. Fergus Falls MN, 56537-0496 United States	Electronic Service		No	24-288Official 24-288
205	Susan	Peirce	susan.peirce@state.mn.us		Department of Commerce	85 Seventh Place East St. Paul MN, 55101 United States	Electronic Service		No	24-288Official 24-288
206	Mary Beth	Peranteau	mperanteau@fredlaw.com	Fredrikson & Byron, P.A.		44 East Mifflin Street Suite 1000 Madison WI, 53703 United States	Electronic Service		No	24-288Official 24-288
207	Jennifer	Peterson	jjpeterson@mnpower.com	Minnesota Power		30 West Superior Street Duluth MN, 55802 United States	Electronic Service		No	24-288Official 24-288
208	Wess	Pfaff	wes.pfaff@mrenergy.com			null null, null United States	Electronic Service		No	24-288Official 24-288
209	Morgan	Pitz	morgan.pitz@us-solar.com	US Solar		100 N 6th St #410B Minneapolis MN, 55403 United States	Electronic Service		No	24-288Official 24-288
210	Hannah	Polikov	hpolikov@aee.net	Advanced Energy Economy Institute		1000 Vermont Ave, Third Floor Washington DC, 20005 United States	Electronic Service		No	24-288Official 24-288
211	Crystal	Pomerleau	crystal.r.pomerleau@xcelenergy.com	Xcel		null null, null United States	Electronic Service		No	24-288Official 24-288
212	Kristel	Porter	kristel@mnrenewablenow.org	MN Renewable Now		null null, null United States	Electronic Service		No	24-288Official 24-288
213	Paula	Prahl	paula.prahl@dominiuminc.com	Dominium		2905 Northwest Blvd Ste 150 Plymouth MN, 55441 United States	Electronic Service		No	24-288Official 24-288
214	Kevin	Pranis	kpranis@liunagroc.com	Laborers' District Council of MN and ND		81 E Little Canada Road St. Paul MN, 55117 United States	Electronic Service		No	24-288Official 24-288
215	David G.	Prazak	dprazak@otpco.com	Otter Tail Power Company		P.O. Box 496 215 South Cascade Street Fergus Falls MN, 56538-0496 United States	Electronic Service		No	24-288Official 24-288
216	Elizabeth	Psihos	elizabeth.psihos@idealenergies.com			null null, null United States	Electronic Service		No	24-288Official 24-288

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
217	Bridget	Rathsack	bridget.rathsack@burnsvillemn.gov	City of Burnsville, MN		100 Civic Center Parkway Burnsville MN, 55337 United States	Electronic Service		No	24-288Official 24-288
218	Peter	Reese	preese@sundialsolarenergy.com	Sundial Energy, LLC		3363 Republic Ave Saint Louis Park MN, 55426 United States	Electronic Service		No	24-288Official 24-288
219	Generic Notice	Regulatory	regulatory_filing_coordinators@otpco.com	Otter Tail Power Company		215 S. Cascade Street Fergus Falls MN, 56537 United States	Electronic Service		No	24-288Official 24-288
220	John C.	Reinhardt		Laura A. Reinhardt		3552 26th Ave S Minneapolis MN, 55406 United States	Paper Service		No	24-288Official 24-288
221	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	24-288Official 24-288
222	Kevin	Reuther	kreuther@mncenter.org	MN Center for Environmental Advocacy		26 E Exchange St, Ste 206 St. Paul MN, 55101-1667 United States	Electronic Service		No	24-288Official 24-288
223	Micah	Revell	micah.revell@stinson.com	Stinson LLP		50 South Sixth St Ste 2600 Minneapolis MN, 55402 United States	Electronic Service		No	24-288Official 24-288
224	Michael	Riewer	mriewer@otpco.com	Otter Tail Power Company		PO Box 4496 Fergus Falls MN, 56538-0496 United States	Electronic Service		No	24-288Official 24-288
225	Jonathan	Roberts	jroberts@soltage.com	Soltage		66 York St 5th Floor Jersey City NJ, 07302 United States	Electronic Service		No	24-288Official 24-288
226	Noah	Roberts	nroberts@cleanpower.org	Energy Storage Association		1155 15th St NW, Ste 500 Washington DC, 20005 United States	Electronic Service		No	24-288Official 24-288
227	Kristi	Robinson	krobinson@star-energy.com	STAR Energy Services, LLC		1401 South Broadway Pelican Rapids MN, 56572 United States	Electronic Service		No	24-288Official 24-288
228	Daniel	Rogers	dan@nokomispartners.com			2639 Nicollet Ave Ste 200 Minneapolis MN, 55408 United States	Electronic Service		No	24-288Official 24-288
229	Michael	Ruiz	michael.ruiz@xcelenergy.com	Xcel Energy		null null, null United States	Electronic Service		No	24-288Official 24-288
230	Nathaniel	Runke	nrunke@local49.org			611 28th St. NW Rochester MN, 55901 United States	Electronic Service		No	24-288Official 24-288
231	Darla	Ruschen	d.ruschen@bcrea.coop	Brown County Rural Electrical Association		PO Box 529 24386 State Highway 4	Electronic Service		No	24-288Official 24-288

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
						Sleepy Eye MN, 56085 United States				
232	Delaney	Russell	delaney@mnipl.org	Just Solar Coalition		4407 E Lake Street Minneapolis MN, 55407 United States	Electronic Service		No	24-288Official 24-288
233	Robert K.	Sahr	bsahr@eastriver.coop	East River Electric Power Cooperative		P.O. Box 227 Madison SD, 57042 United States	Electronic Service		No	24-288Official 24-288
234	Ian	SantosMeeker	ians@ips-solar.com	IPS Solar		null null, null United States	Electronic Service		No	24-288Official 24-288
235	Joseph L	Sathe	jsathe@kennedy-graven.com	Kennedy & Graven, Chartered		150 S 5th St Ste 700 Minneapolis MN, 55402 United States	Electronic Service		No	24-288Official 24-288
236	Kenric	Scheevel	kjs@dairynet.com	Dairyland Power Cooperative		3200 East Ave S PO Box 817 La Crosse WI, 54602 United States	Electronic Service		No	24-288Official 24-288
237	Dean	Schiro	dean.e.schiro@xcelenergy.com	Xcel Energy		null null, null United States	Electronic Service		No	24-288Official 24-288
238	Jacob J.	Schlesinger	jschlesinger@keyesfox.com	Keyes & Fox LLP		1580 Lincoln St Ste 880 Denver CO, 80203 United States	Electronic Service		No	24-288Official 24-288
239	Jeff	Schoenecker	jschoenecker@dakotaelectric.com	Dakota Electric Association		4300 220th Street W Farmington MN, 55024 United States	Electronic Service		No	24-288Official 24-288
240	Kay	Schraeder	kschraeder@minnkota.com	Minnkota Power		5301 32nd Ave S Grand Forks ND, 58201 United States	Electronic Service		No	24-288Official 24-288
241	Matthew	Schuerger	matthew.schuerger@state.mn.us		Public Utilities Commission	121 7th Place East Suite 350 St. Paul MN, 55101 United States	Electronic Service		No	24-288Official 24-288
242	Ronald J.	Schwartau	rschwartau@noblesce.com	Nobles Electric Cooperative		22636 U.S. Hwy. 59 Worthington MN, 56187 United States	Electronic Service		No	24-288Official 24-288
243	Rob	Scott Hovland	rob.scott-hovland@mrenergy.com	Missouri River Energy Services		3724 W Avera Dr PO Box 88920 Sioux Falls SD, 57109-8920 United States	Electronic Service		No	24-288Official 24-288
244	Dean	Sedgwick	sedgwick@itascapower.com	Itasca Power Company		PO Box 455 Spring Lake MN, 56680 United States	Electronic Service		No	24-288Official 24-288
245	Maria	Seidler	maria.seidler@dom.com	Dominion Energy Technology		120 Tredegar Street Richmond VA, 23219 United States	Electronic Service		No	24-288Official 24-288
246	David	Shaffer	david.shaffer@novelenergy.biz	Novel Energy Solutions		2303 Wycliff St Ste 300 St. Paul MN, 55114 United States	Electronic Service		No	24-288Official 24-288

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
247	Patricia	Sharkey	psharkey@environmentallawcounsel.com	Midwest Cogeneration Association.		180 N LaSalle St Ste 3700 Chicago IL, 60601 United States	Electronic Service		No	24-288Official 24-288
248	Christopher L.	Sherman	csherman@sherman-associates.com	Solar Holdings LLC		233 Park Ave S Ste 201 Minneapolis MN, 55415 United States	Electronic Service		No	24-288Official 24-288
249	Doug	Shoemaker	dougs@charter.net	Minnesota Renewable Energy		2928 5th Ave S Minneapolis MN, 55408 United States	Electronic Service		No	24-288Official 24-288
250	Felicia	Skaggs	fskaggs@meeker.coop	Meeker Cooperative Light & Power		1725 US Highway 12 E Suite 100 Litchfield MN, 55355 United States	Electronic Service		No	24-288Official 24-288
251	Glen	Skarbakka	glen@s-pllc.com	Skarbakka PLLC		5411 Bartlett Blvd Mound MN, 55364 United States	Electronic Service		No	24-288Official 24-288
252	Anne	Smart	anne.smart@chargepoint.com	ChargePoint, Inc.		254 E Hacienda Ave Campbell CA, 95008 United States	Electronic Service		No	24-288Official 24-288
253	Joshua	Smith	joshua.smith@sierraclub.org			85 Second St FL 2 San Francisco CA, 94105 United States	Electronic Service		No	24-288Official 24-288
254	Ken	Smith	ken.smith@ever-greenenergy.com	Ever Green Energy		305 Saint Peter St Saint Paul MN, 55102 United States	Electronic Service		No	24-288Official 24-288
255	Ken	Smith	ken.smith@districtenergy.com	District Energy St. Paul Inc.		76 W Kellogg Blvd St. Paul MN, 55102 United States	Electronic Service		No	24-288Official 24-288
256	Trevor	Smith	trevor.smith@avantenergy.com	Avant Energy, Inc.		220 South Sixth Street Suite 1300 Minneapolis MN, 55402 United States	Electronic Service		No	24-288Official 24-288
257	Rafi	Sohail	rafi.sohail@centerpointenergy.com	CenterPoint Energy		800 LaSalle Avenue P.O. Box 59038 Minneapolis MN, 55459-0038 United States	Electronic Service		No	24-288Official 24-288
258	Beth	Soholt	bsoholt@cleangridalliance.org	Clean Grid Alliance		570 Asbury Street Suite 201 St. Paul MN, 55104 United States	Electronic Service		No	24-288Official 24-288
259	Marcia	Solie	m.solie@bcrea.coop	Brown County Rural Electrical Association		24386 State Hwy. 4, PO Box 529 Sleepy Eye MN, 56085 United States	Electronic Service		No	24-288Official 24-288
260	Braden	Solum	braden.solum@idealenergies.com	iDEAL Energies		5810 Nicollet Ave Minneapolis MN, 55419 United States	Electronic Service		No	24-288Official 24-288

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
261	Karl	Sonneman	karl17@hbci.com	Law Office of Karl W. Sonneman		111 Riverfront Suite 202 Winona MN, 55987 United States	Electronic Service		No	24-288Official 24-288
262	Brandon	Stamp	brandon.j.stamp@xcelenergy.com	Xcel Energy		401 Nicollet Mall Minneapolis MN, 55401 United States	Electronic Service		No	24-288Official 24-288
263	Sky	Stanfield	stanfield@smwlaw.com	Shute, Mihaly & Weinberger		396 Hayes Street San Francisco CA, 94102 United States	Electronic Service		No	24-288Official 24-288
264	Russ	Stark	russ.stark@ci.stpaul.mn.us	City of St. Paul		Mayor's Office 15 W. Kellogg Blvd., Suite 390 Saint Paul MN, 55102 United States	Electronic Service		No	24-288Official 24-288
265	Byron E.	Starns	byron.starns@stinson.com	STINSON LLP		50 S 6th St Ste 2600 Minneapolis MN, 55402 United States	Electronic Service		No	24-288Official 24-288
266	Kristin	Stastny	kstastny@taftlaw.com	Taft Stettinius & Hollister LLP		2200 IDS Center 80 South 8th Street Minneapolis MN, 55402 United States	Electronic Service		No	24-288Official 24-288
267	Lindsey	Stegall	lindsey.stegall@evgo.com	EVgo Services, LLC		11835 W Olympic Blvd Ste 900E Los Angeles CA, 90064 United States	Electronic Service		No	24-288Official 24-288
268	Cary	Stephenson	cstephenson@otpco.com	Otter Tail Power Company		215 South Cascade Street Fergus Falls MN, 56537 United States	Electronic Service		No	24-288Official 24-288
269	Sherry	Swanson	sswanson@noblesce.com	Nobles Cooperative Electric		22636 US Highway 59 PO Box 788 Worthington MN, 56187 United States	Electronic Service		No	24-288Official 24-288
270	Bryant	Tauer	btauer@whe.org	Wright-Hennepin		6800 Electric Dr Rockford MN, 55373 United States	Electronic Service		No	24-288Official 24-288
271	Dean	Taylor	dtaylor@pluginamerica.org	Plug In America		6380 Wilshire Blvd, Suite 1000 Los Angeles CA, 90048 United States	Electronic Service		No	24-288Official 24-288
272	Whitney	Terrill	whitney@mnipl.org	Minnesota Interfaith Power & Light		null null, null United States	Electronic Service		No	24-288Official 24-288
273	Stuart	Tommerdahl	stommerdahl@otpco.com	Otter Tail Power Company		215 S Cascade St PO Box 496 Fergus Falls MN, 56537 United States	Electronic Service		No	24-288Official 24-288
274	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	24-288Official 24-288

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
275	Jason	Topp	jason.topp@lumen.com	Qwest Communications Company, LLC.		200 S 5th St Ste 2200 Minneapolis MN, 55402 United States	Electronic Service		No	24-288Official 24-288
276	Emma Marshall	Torres	emarshall-torres@convergentep.com			null null, null United States	Electronic Service		No	24-288Official 24-288
277	Zack	Townsend	zachary.townsend@brookfieldrenewable.com	Brookfield Renewable		200 Liberty St FL 14 New York NY, 10281 United States	Electronic Service		No	24-288Official 24-288
278	Pat	Treseler	pat.jcplaw@comcast.net	Paulson Law Office LTD		4445 W 77th Street Suite 224 Edina MN, 55435 United States	Electronic Service		No	24-288Official 24-288
279	Jeff	Triplett	triplettj@powersystem.org	MREA		10710 Town Square Dr NW St 201 Minneapolis MN, 55449 United States	Electronic Service		No	24-288Official 24-288
280	Adam	Tromblay	atromblay@noblesce.com	Nobles Cooperative Electric		22636 US Hwy. 59 P.O. Box 788 Worthington MN, 56187-0788 United States	Electronic Service		No	24-288Official 24-288
281	Lise	Trudeau	lise.trudeau@state.mn.us		Department of Commerce	85 7th Place East Suite 500 Saint Paul MN, 55101 United States	Electronic Service		No	24-288Official 24-288
282	Alan	Urban	alan.m.urban@xcelenergy.com	Xcel Energy		null null, null United States	Electronic Service		No	24-288Official 24-288
283	Gary	Van Winkle	gvanwinkle@mylegalaid.org	Mid-Minnesota Legal Aid		111 N Fifth St Ste 100 Minneapolis MN, 55403 United States	Electronic Service		No	24-288Official 24-288
284	John	Vaughn	nik@rreal.org	Rural Renewable Energy Alliance		3963 8th Street SW Backus MN, 55435 United States	Electronic Service		No	24-288Official 24-288
285	Ellen	Veazey	lveazey@solarunitedneighbors.org	Solar United Neighbors		1350 Connecticut Ave NW Ste 412 Washington DC, 20036 United States	Electronic Service		No	24-288Official 24-288
286	Sam	Villella	sdvillella@gmail.com			10534 Alamo Street NE Blaine MN, 55449 United States	Electronic Service		No	24-288Official 24-288
287	Curt	Volkmann	curt@newenergy-advisors.com	Fresh Energy		408 St Peter St Saint Paul MN, 55102 United States	Electronic Service		No	24-288Official 24-288
288	Wendy	Vorasane	wendy.vorasane@idealenergies.com			null null, null United States	Electronic Service		No	24-288Official 24-288
289	Robert J.V.	Vose	rvose@kennedy-graven.com	Kennedy & Graven, Chartered		150 S 5th St Ste 700 Minneapolis MN, 55402 United States	Electronic Service		No	24-288Official 24-288

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
290	Stacy	Wahlund	swahlund@otpco.com	Otter Tail Power Company		215 S. Cascade St Fergus Falls MN, 56537 United States	Electronic Service		No	24-288Official 24-288
291	Sarah	Walinga	swalinga@solarcity.com	Energy Freedom Coalition		3055 Clearview Way San Mateo MN, 94402 United States	Electronic Service		No	24-288Official 24-288
292	Kevin	Walker	kwalker@beaconinterfaith.org	Beacon Interfaith Housing Collaborative		null null, null United States	Electronic Service		No	24-288Official 24-288
293	Roger	Warehime	roger.warehime@owatonnautilities.com	Owatonna Municipal Public Utilities - Gas		208 S Walnut Ave PO BOX 800 Owatonna MN, 55060 United States	Electronic Service		No	24-288Official 24-288
294	Jenna	Warmuth	jwarmuth@mnpower.com	Minnesota Power		30 W Superior St Duluth MN, 55802-2093 United States	Electronic Service		No	24-288Official 24-288
295	Samantha	Weaver	samantha@communitysolaraccess.org	Coalition for Community Solar Access		1380 Monroe St. Washington DC DC, 20010 United States	Electronic Service		No	24-288Official 24-288
296	Elizabeth	Wefel	eawefel@flaherty-hood.com	Missouri River Energy Services		525 Park St Ste 470 Saint Paul MN, 55103 United States	Electronic Service		No	24-288Official 24-288
297	Joshua	Williams	joshua@highlandfleets.com	Highland Electric Fleets		200 Cummings Center Suite 273-D Beverly MA, 01915 United States	Electronic Service		No	24-288Official 24-288
298	Laurie	Williams	laurie.williams@sierraclub.org	Sierra Club		Environmental Law Program 1536 Wynkoop St Ste 200 Denver CO, 80202 United States	Electronic Service		No	24-288Official 24-288
299	John	Williamson	john.williamson@state.mn.us	Minnesota Department of Labor and Industry		443 Lafayette Rd N St. Paul MN, 55155-4341 United States	Electronic Service		No	24-288Official 24-288
300	Anthony	Willingham	anthony.willingham@electrifyamerica.com	Electrify America		1950 Opportunity Way Suite 1500 Reston VA, 20190 United States	Electronic Service		No	24-288Official 24-288
301	Danielle	Winner	danielle.winner@state.mn.us		Department of Commerce	85 7th Place East Suite 500 Saint Paul MN, 55101 United States	Electronic Service		No	24-288Official 24-288
302	Heidi	Winter	hwinter@co.murray.mn.us	Murray County		2500 28th Street PO Box 57 Slayton MN, 56172 United States	Electronic Service		No	24-288Official 24-288
303	Robyn	Woeste	robynwoeste@alliantenergy.com	Interstate Power and Light Company		200 First St SE Cedar Rapids	Electronic Service		No	24-288Official 24-288

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
						IA, 52401 United States				
304	Terry	Wolf	terry.wolf@mrenergy.com	Missouri River Energy Services		3724 W Avera Dr PO Box Sioux Falls SD, 57109-8920 United States	Electronic Service		No	24-288Official 24-288
305	Curtis	Zaun	curtis@cpzlaw.com			3254 Rice Street Little Canada MN, 55126 United States	Electronic Service		No	24-288Official 24-288
306	Brian	Zavesky	brianz@mrenergy.com	Missouri River Energy Services		3724 West Avera Drive P.O. Box 88920 Sioux Falls SD, 57108-8920 United States	Electronic Service		No	24-288Official 24-288
307	Christopher	Zibart	czibart@atcllc.com	American Transmission Company LLC		W234 N2000 Ridgeview Pkwy Court Waukesha WI, 53188-1022 United States	Electronic Service		No	24-288Official 24-288
308	Kurt	Zimmerman	kwz@ibew160.org	Local Union #160, IBEW		2909 Anthony Ln St Anthony Village MN, 55418-3238 United States	Electronic Service		No	24-288Official 24-288
309	Emily	Ziring	eziring@stlouispark.org	City of St. Louis Park		5005 Minnetonka Blvd St. Louis Park MN, 55416 United States	Electronic Service		No	24-288Official 24-288