414 Nicollet Mall
Minneapolis, MN 55401

March 13, 2025

—Via Electronic Filing—

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

RE: UTILITY RESPONSE
IN THE MATTER OF UPDATING THE GENERIC STANDARDS FOR THE INTERCONNECTION AND OPERATION OF DISTRIBUTED GENERATION FACILITIES ESTABLISHED UNDER MINN. STAT. §216B.1611
DOCKET NO. E999/CI-16-521

Dear Mr. Seuffert:

Northern States Power Company, doing business as Xcel Energy, submits these Utility Comments in response to the February 10, 2025, Notice of Comment Period (Notice). The Notice was issued as a result of a Letter filed by the Joint Solar Associations (JSA) on December 13, 2024, regarding Xcel Energy's internal transmission studies (ITS).

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 Kristen Ruud at Kristen.S.Ruud@xcelenergy.com or 612-216-7979 if you have any questions concerning this filing.

Sincerely,

/s/

JESSICA PETERSON
MANAGER, PROGRAM POLICY

Enclosures
c: Service List

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

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

IN THE MATTER OF UPDATING THE GENERIC STANDARDS FOR THE INTERCONNECTION AND OPERATION OF DISTRIBUTED GENERATION FACILITIES ESTABLISHED UNDER MINN. STAT. §216B.1611	DOCKET NO. E999/CI-16-521 **UTILITY COMMENTS**

INTRODUCTION

Northern States Power Company, doing business as Xcel Energy, submits these Utility Comments in response to the February 10, 2025 Notice of Comment Period (Notice). The Notice was issued as a result of a Letter filed by the Joint Solar Associations (JSA) on December 13, 2024 regarding Xcel Energy's internal transmission studies (ITS).[1]

The Commission Notice identified two main issues and several topics open for comment. The Minnesota Distributed Energy Resources (DER) Interconnection Process (MN DIP) recognizes that when there is potential for transmission system adverse impacts from DER interconnection, then a transmission System Impact Study (SIS) is required.[2] The Transmission Provider then completes the necessary studies to determine if the DER causes any adverse transmission impacts. Indeed, reviewing potential DER applications for adverse impacts to the transmission system is not only required by the MN DIP but also necessary to comply with the reliability standards for transmission grid developed by the North American Electric Reliability Corporation (NERC). The review of adverse impacts on transmission is also prudent for the maintenance of the electric grid –providing safe and reliable service to our customers – including those customers building new DER projects.

[1] JSA included Clean Energy Economy MN (CEEM), the Minnesota Solar Energy Industries Association (MnSEIA), and the Coalition for Community Solar Access (CCSA).
[2] MN DIP 4.3.6 uses obligatory language, stating that the "Area EPS Operator *shall* coordinate with the appropriate Transmission Provider to have the necessary studies completed."

In the remainder of these comments, the Company provides further detail regarding unnecessary suggestions to amend the MN DIP. There is no need to amend the MN DIP to clarify the Affected System study process when the Transmission Owner is also the Area EPS Operator. The MN DIP does not limit the authority to conduct transmission studies to one Transmission Provider, such as the Midcontinent Independent System Operator (MISO), but allows "the appropriate Transmission Provider" to complete the necessary studies, and the MN DIP definition of this term includes the Transmission Owner. As we describe in more detail below, there is no doubt that Xcel Energy qualifies as a Transmission Provider under MN DIP definitions.

The Company has worked with MISO on transmission analysis for several years. In fact, we helped to identify the need for further analysis on the transmission system that led to the subsequent changes in the MISO study process. MISO began implementation of its formal transmission study process as a direct result of the rapid growth of DER interconnections in the Midwest. The current MISO process to evaluate DER transmission system impacts was implemented in October 2023 and is known as the MISO DER Affected Systems Study (MISO DER AFS). This process is documented as part of the MISO Business Practice Manual (MPM-015, Generation Interconnection).[3] Xcel Energy has sent over 30 Minnesota DER applications to MISO for transmission review.

MISO has been clear that the MISO DER AFS process does not preclude other studies of risks to the transmission system from DER projects that do not trigger a MISO review. The MISO process did not remove the need for our internal transmission analysis and we have modified our process to account for the changes at MISO, verifying that the Xcel Energy ITS and MISO DER AFS are non-duplicative, use different triggers that prompt evaluation of potential adverse transmission impacts, and comply with MN DIP 4.3.6. When a MISO DER AFS review is triggered, then the Xcel Energy ITS is not performed.

The Company implemented its ITS process also in fall 2023, starting screening for those interconnection applications that had not yet reached the Facilities Study stage by September 1, 2023. As of March 3, 2025, the Company has undertaken and completed one ITS study comprised of five projects in five separate substations. The findings of that study did not result in any transmission upgrades to those substations. In addition, the Company is in the process of analyzing additional 15 projects (at 13

[3] This is available at: https://www.misoenergy.org/legal/rules-manuals-and-agreements/business-practice-manuals/. Materials specific to the MISO DER AFS section begin in section 8, at PDF page 130. PDF pages 4-5 of this document show that the MISO DER AFS content was added on August 2, 2023.

substations) in a Q1 2025 ITS study – the results are pending. Of note, the amount of projects in the Company's transmission analysis is much less than JSA has sensationalized at 90 percent of all pending projects in queue (December 13, 2024 Letter, p. 2).

As we describe in more detail below when we respond to the specific topics listed in the Notice, there are no reasonable grounds to open an investigation on Xcel Energy's ITS process and no need to cease the current ITS process or receive Commission approval. Similarly, we believe the current MN DIP language on the transmission System Impact Study is sufficient.

These Utility Comments include the following Attachments:

- Attachment A: NERC Standard FAC-002-4.
- Attachment B: NERC Standard FAC-011-4.
- Attachment C: Excerpts from the Commission's Technical Planning Standard (TPS) Appellate Brief, filed September 24, 2024.
- Attachment D: Excerpts from various filings with the Commission from August 2022 to December 2024 on the MISO DER AFS and ITS processes.
- Attachment E: Transmission SIS Agreement applicable to the ITS.

COMMENTS

I. BACKGROUND

DER projects are interconnected directly to the utility's distribution system. The MN DIP governs the interconnection process for systems no more than 10 MW and focuses on the impacts of the DER on the safety and reliability of the distribution system. The transmission system was planned and designed to serve distribution load by transmitting energy from the generation source to the distribution system, which then delivers the energy to the load customer. If the distribution system is back-feeding to the transmission system, this is a condition that did not exist when the transmission system was originally designed. If DER interconnection may cause new or increased reverse backflow into the substation and transmission system, this must be evaluated in a transmission study.

The Company has expended substantial efforts to interconnect an extensive amount of DER in Minnesota.[4] The rapid growth of interconnected DER has resulted in some unintended consequences. For example, there are many Xcel Energy locations in Minnesota where the DER capacity exceeds the amount of customer load. When the aggregate interconnected DER on a substation exceeds the customer load, there are potential adverse impacts on the transmission system regardless of whether this happens not only when DER exceeds peak load conditions but also when DER exceeds daytime minimum load conditions. In both situations, there is backflow onto the transmission system, and any new interconnected DER would create additional backflow.

NERC develops Reliability Standards for the transmission grid. After the Reliability Standards have been approved by the Federal Energy Regulatory Commission (FERC), they become mandatory and enforceable in the United States. When there is concern that DER interconnections may cause adverse transmission system impacts, Xcel Energy is obligated to conduct transmission studies to ensure compliance with NERC Reliability Standards.[5] For example, under NERC Standard FAC-002-4, Xcel Energy is required to study the reliability impact of interconnecting new generation or transmission to be compliant with applicable NERC Reliability Standards as well as regional and Transmission Owner planning criteria. This NERC Standard FAC-002-4 is attached as Attachment A. This states in part:

> R1. Each Transmission Planner and each Planning Coordinator shall study the reliability impact of: (i) interconnecting new generation, transmission, or electricity end-user Facilities and (ii) existing interconnections of generation, transmission, or electricity end-user Facilities seeking to make a qualified change as defined by the Planning Coordinator under Requirement R6. The following shall be studied: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]
>
> 1.1. The reliability impact of the new interconnection, or existing interconnection seeking to make a qualified change as defined by the Planning Coordinator under Requirement R6, on affected system(s);
>
> 1.2. Adherence to applicable NERC Reliability Standards; regional and Transmission Owner planning criteria; and Facility interconnection requirements;

[4] This is well documented in many filings with the Commission, including the Company's October 20, 2023 Comments in Docket No. E002/C-23-424, at page 6.

[5] One of the earlier Independent Engineer reports in the CSG docket concluded that NERC Standards are applicable to DER interconnections because the impacted substation is tied to a wider transmission network. IE Bartlett Report at p. 37. (Attached to the Company's May 3, 2016 filing in Docket Nos. 13-867 and 15-786.)

1.3. Steady-state, short-circuit, and dynamics studies, as necessary, to evaluate system performance under both normal and contingency conditions; and
1.4. Study assumptions, system performance, alternatives considered and coordinated recommendations. While these studies may be performed independently, the results shall be evaluated and coordinated by the entities involved.

M1. Each Transmission Planner or each Planning Coordinator shall have evidence (such as study reports, including documentation of reliability issues) that it met all requirements in Requirement R1.

NERC Standard FAC-011-4 specifically requires that Xcel Energy's transmission system remains between all thermal and voltage facility ratings. This NERC Standard FAC-011-4 is attached as Attachment B.

By performing its own transmission studies, Xcel Energy remains compliant with the NERC standards and can demonstrate compliance to NERC, which is also a NERC requirement. The Company is obligated to perform the ITS in order to be compliant with NERC requirements when there is back-feed onto the transmission system and a MISO DER AFS review has not been triggered. In addition, conducting the ITS prior to DER interconnection helps to identify risks and implement upgrades in advance to mitigate these risks. Otherwise, without the upfront study, Xcel Energy would need to take immediate action if its Transmission Operations group observes that the transmission system is out of compliance with NERC requirements (such as thermal overload conditions or voltage deviation) due to excessive DER on the system.

II. RESPONSES TO COMMISSION QUESTIONS

A. Explain how Xcel Energy's current internal transmission studies are consistent with the MN DIP.

The MN DIP recognizes that when there is potential for transmission system adverse impacts from DER interconnection, then a transmission SIS is required. MN DIP 4.3.6 states:

4.3.6 In instances where the System Impact Study shows potential for Transmission System adverse system impacts, within five (5) Business Days following the identification of such impacts by the Area EPS Operator, the Area EPS Operator shall coordinate with the appropriate

Transmission Provider to have the necessary studies completed to determine if the DER causes any adverse transmission impacts.

The Company's ITS is only conducted when the distribution SIS for a project shows potential for adverse transmission impacts. The distribution SIS studies DER impacts on the distribution system, while the transmission SIS studies DER impacts on the transmission system when there is backflow to the transmission system and need to determine whether the transmission system voltage and thermal limits would remain within NERC standards. We also note that MN DIP 4.3.6 uses obligatory language, "the Area EPS Operator *shall* coordinate with the appropriate Transmission Provider" when the distribution SIS shows potential for adverse transmission impacts. Therefore, a transmission SIS is a mandatory process under the MN DIP to protect the safety and reliability of the transmission system.

Xcel Energy owns and operates substations and other transmission facilities and therefore qualifies under the MN DIP definitions as being both a Transmission Owner and a Transmission Provider. We also note that the MN DIP does not limit the authority to conduct transmission studies to one Transmission Provider, such as MISO, but allows "the *appropriate* Transmission Provider" to complete the necessary studies.

The MN DIP provides the following pertinent definitions in its Glossary of Terms:

- ***Transmission Owner:*** *The entity that owns, leases or otherwise possesses an interest in the portion of the Transmission System relevant to the Interconnection.*
- ***Transmission Provider:*** *The entity (or its designated agent) that owns, leases, controls, or operates transmission facilities used for the transmission of electricity. The term Transmission Provider includes the Transmission Owner when the Transmission Owner is separate from the Transmission Provider. The Transmission Provider may include the Independent System Operator or Regional Transmission Operator.*

Xcel Energy is a Transmission Owner because it owns or otherwise possesses an interest in the portion of the transmission system relevant to interconnection of DER systems that are interconnected in its service territory. Xcel Energy is a Transmission Provider because it owns, leases, controls, or operates transmission facilities used for the transmission of electricity. Further, because Xcel Energy is a Transmission Owner it directly qualifies as being a Transmission Provider. MISO also qualifies as a Transmission Provider.

The Company's ITS is permissible under MN DIP 4.3.6, 4.3.7, and 4.3.8 and complies with these MN DIP provisions. Xcel Energy owns and operates substations and other

transmission facilities and therefore qualifies under the MN DIP definitions as being both a Transmission Owner and a Transmission Provider. MISO is also a Transmission Provider under the MN DIP definition because it controls the transmission facilities.

1. Prudency of Transmission Analysis

Below, the Company discusses how its Transmission Operations group has identified situations where there was thermal overloading of the transmission system or voltage deviations on the transmission system due to excessive DER. This called into question how the Company could better comply with the NERC and FERC requirements so that these types of situations are avoided, and that the Company should study DER applications' impact on the transmission system before they are interconnected to avoid these types of situations.

The Company has explained previously in this docket how some other utilities have approached the risk associated with DER back-feeding to the transmission network. The Company's January 11, 2022 Letter noted that Duke Energy Carolinas had about 730 MW of DER applications "on hold" in their interconnection queue, and that Duke Energy had implemented "Methods of Service Guidelines" that do not allow DER generation back-feed across any field regulators. The Company also noted that the Public Utility Commission of Oregon had approved an approach where Community Solar interconnection applications were only allowed to be in the Community Solar queue if the capacity of the proposed Community Solar generator, together with all other interconnected and requested generation in the local areas, was less than 100 percent of the daytime minimum load (DML). The Company's ITS is far more permissive to DER than either of these approaches.

The JSA has previously asked whether the Xcel Energy operating company affiliates in other states also use the ITS (December 13, 2024 Letter, p. 8, fn. 7). The Xcel Energy operating company affiliates use a process consistent with the ITS in all of their service territories so that all DERs that exceed daytime minimum load are subject to a transmission study. However, we note that not all service territories of the Xcel Energy affiliates in eight states are subject to the MISO DER AFS process.

Based on our experience described here, there is a potential for adverse system impacts when DER exceeds DML. That potential cannot be disproved until a study is performed and shows that there is no potential for such adverse impacts. The Company believes that it is prudent to perform an ITS to determine whether the DER should be allowed to proceed only if certain transmission upgrades are

constructed, if the ITS shows that they are required. Furthermore, NERC regulations specifically require this study.

2. Allowed by Minnesota Statute

MnSEIA and others have argued that the ITS cannot be allowed under MN DIP because doing so would violate various state statutes, such as Minn. Stat. §§ 216B.1611, 216B.03, 216B.05, and 216B.16. The Commission in its September 24, 2024, Appellate Brief on the Technical Planning Standard (TPS) Appeal from Docket No. E-002/C-23-424[6] clearly shows that Minn. Stat. § 216B.1611 is inapplicable. The Company below discusses the Commission's approach to the TPS Appeal because this is closely aligned with the same legal issues being raised for the ITS. Relevant excerpts of the Appellate Brief are included as Attachment C.

The TPS helps to determine how a distribution SIS needs to be conducted, and the ITS is conducted when a trigger has been met for requiring a transmission SIS. The Commission's Appellate Brief explained how under this statute the Commission established the MN DIP as a generic standard for interconnecting DER, and that the standards under MN DIP reflect the characteristics and needs of the utility by taking into account differing system requirements and overall load requirements of individual utilities. The MN DIP standards must also reflect terms that allow a utility to be assured of the reliable, safe and efficient operation of the interconnected equipment. And, Minn. Stat. § 216B.1611 "… relates to Commission adoption of standards …, not utility practice…" (Appellate Brief, pp. 7, 13).

The Commission went on to explain that MnSEIA had argued that there is a requirement for a utility to file a tariff for distributed generation for Commission approval in Minn. Stat. § 216B.1611, subdivision 3, but the Commission observed that Xcel Energy has an approved tariff for distributed generation in place. The Commission observed that the Supreme Court has held that a utility tariff need not govern the entirety of the relationship between a utility and its customer. *Siewert v. Northern States Power Co.*, 793 N.W.2d 272, 281 (Minn. 2011), and stated that Section 216B.1611 requires only a distributed generation tariff that is consistent with the generic standards set forth in MN DIP and MN TIIR. With respect to any greater specificity, such as the TPS, the Commission exercises its discretion to determine whether that standard is properly included in the utility's tariff. Minn. Stat. § 216B.05, subd. 2. The same approach applies to the ITS.

[6] *In the Matter of the Formal Complaint and Request for Relief by the Minnesota Solar Advocates.* This is the subject of the appeal before the Minnesota Court of Appeals in Docket No. A24-0845.

The Commission also distinguished other statutes cited here, and the Commission's explanation is applicable also to this case. The Commission noted "… not every utility practice constitutes a 'rate' that must be approved by the Commission under Minnesota Statutes Section 216B.16." The Commission in defending its order noted the Xcel Energy argument that the TPS does not create discriminatory or unreasonable rates, or unreasonably prejudice or disadvantage customers (addressing Minn. Stat. §§ 216B.03, .05 and .07) because it is based on Xcel Energy's judgment as to what is required for safety and reliability, and that MnSEIA failed to show how the TPS was discriminatory. These same arguments fully apply here to the ITS.

The Commission also stated that other statutes cited by MnSEIA are based on the false notion that every utility practice constitutes a "rate" that must be approved by the Commission. The Commission noted that MnSEIA's expansive reading of "rate" would logically encompass every single practice of a utility, which must come at some expense, a position that even MnSEIA had disavowed. Also, the Commission noted that every aspect of the relationship between a utility and its customers is not reflected in a tariff, citing *Siewert*, 793 N.W.2d at 281. The Commission further explained that the TPS cannot constitute a rate simply because it remains subject to modification and further discussion pursuant to the Commission's Order. The Commission may, at some point, determine that an interconnection planning standard is appropriate to include in Xcel Energy's tariff as affecting utility service. But the Commission determined that additional discussion and possible refinement of Xcel Energy's standard was appropriate, making any inclusion of the TPS in the tariff premature. The Commission determined that the TPS is not a "rate" under the statutory definition and the adoption of the TPS is not a rate change subject to Commission approval under Minn. Stat. § 216B.16. The same analysis applies here as Xcel Energy is open to further modifications to the ITS as explained further in the present filing.

The Commission concluded that the TPS is based on both engineering decisions and policy objectives and that there is no statutory directive that requires the Commission to approve or disapprove the TPS. The Commission cited Minn. Stat. § 216B.05 to support its conclusion that the Legislature left it to the Commission's judgment as to which practices are to be included in tariff, and that the Commission properly concluded that the TPS should not be included in a tariff. (see, Appellate Brief, pp. 22-24, contained in Attachment C). This same analysis should apply to the ITS.

Under the MN DIP, as explained by the Commission, it is up to each Transmission Provider to use their engineering judgment and technical analysis to determine if there is a potential for adverse system impacts.

B. What is Xcel Energy's current approach and process regarding their internal transmission studies?

- Please explain the evolution of the Company's approach to transmission studies, both internal and MISO derived and the reason for that evolution.

DER interconnection projects may require a transmission SIS when the Company identifies as part of the SIS that back-feed will occur on the transmission system. Indeed, this occurs under the following adopted triggers for transmission review:

- If the aggregate DER exceeds substation peak load by at least 1MW, the project is sent to the quarterly MISO DER AFS process; or
- If the substation has more than 750 kW of aggregate DER and the aggregate DER exceeds substation Daytime Minimum Load (DML) (but does not exceed substation peak load by 1 MW), the project is studied in Xcel Energy's quarterly ITS process.

The evolution of this includes the discussion above and the sections below.

1. MISO Transmission Study Process

The Company began to have concern with adverse impacts on the transmission grid as a result of the increased growth of DER in the 2017-2019 timeframe. The Company's Transmission Operations group had evidence of adverse impacts, such as high voltage and voltage fluctuations, and consequently notified the Company's Transmission Planning group of these incidents, which included situations where DER exceeded DML but did not exceed peak load. As a result, the Company expressed its concerns to MISO and began working with MISO in 2020 to create a written process and standards for MISO transmission impact review. The Company also explained to developers its work with MISO during this timeframe in 2021.[7] This resulted in the MISO Affected System Impact Study Agreement (MISO ASIS Agreement) between MISO and Xcel Energy addressing how MISO would conduct its transmission studies for DER applications. While the Commission in its March 31, 2022, Order barred the use of the MISO ASIS Agreement, the Order did not impact MISO's authority to conduct its transmission studies under the MN DIP.[8] This Order

[7] See, for example, a summary of the history of these communications in 2021 as reflected on page 2 of the Company's March 21, 2022 Comments in this docket.

[8] We note that MISO has never used the MISO ASIS Agreement that was a subject of the Commission's March 31, 2022 Order in this docket.

specifically stated: "Further, the stay does not impact the current MN DIP-approved Affected System Study process used by utilities and MISO."

After extensive outreach and workgroups, MISO implemented the MISO DER AFS process in October 2023. Prior to the MISO DER AFS process, MISO conducted DER transmission studies on a case-by-case basis. By January 2023, MISO had accepted for study its first DER project under the "ad hoc" process and the results showed that the transmission upgrade costs would be approximately $8 million if the project were to move forward.

MISO determined that growing DER interconnections within the distribution system across the MISO footprint necessitated a more formal process to consistently evaluate DER transmission system impacts. Therefore, MISO led a stakeholder meeting series throughout 2022 to develop the MISO DER AFS procedures and technical criteria to evaluate potential DER reliability impacts. The MISO Interconnection Process Working Group (IPWG) met six times in 2022 to discuss the framework, technical thresholds, coordination, analysis, and results for MISO's DER AFS. As described further below, the Company kept developers and parties apprised of the IPWG process and the evolving nature of the transmission studies. MnSEIA even attended and participated in some of the MISO IPWG sessions. During the IPWG meetings, MISO was clear that its DER AFS process would not prohibit Transmission Owners from conducting their own transmission studies on DER interconnection applications. Additional information on the IPWG, including its meeting minutes, are available on MISO's website.[9]

MISO conducts DER AFS on a quarterly basis and the study cycles are published on MISO website.[10] When a DER application for interconnection meets the MISO trigger for DER AFS screening, Xcel Energy (and any other utility) is obligated to submit the project to MISO for screening. The trigger for MISO screening is when the aggregate DER exceeds the substation peak load by at least 1 MW. If the MISO DER AFS screening shows that a full study is needed, MISO will invoice Xcel Energy for the study fee of $60,000. The project must timely pay the study deposit to Xcel Energy, who will then forward the payment to MISO. The final MISO report of study results is published approximately six months after the screening is completed.

[9] https://www.misoenergy.org/engage/committees/interconnection-process-working-group/
[10] https://www.misoenergy.org/planning/resource-utilization/distribution/#t=10&p=0&s=FileName&sd=desc

If MISO screening shows that a full study is not needed, then the DER project typically does not require any additional study on transmission impacts and Xcel Energy will not conduct its own ITS for the project.

The Company has regularly informed developers about the ITS and MISO transmission study processes for DER interconnection, both before and after they were implemented. These communications took place through various filings in Docket Nos. 13-867 and 16-521 as well as several workgroups referenced in these filings. We include pertinent excerpts from these filings in Attachment D, covering the timeframe from August 2022 through December 2024. They show how Xcel Energy has provided frequent updates to developers about the ITS and MISO DER AFS processes.

These excerpts include the following with respect to the MISO DER AFS:

- Show that MISO by January 2023 accepted for study its first DER project under its "ad hoc" process (Attachment D, page 8);
- Provide details on the development of MISO workgroups on this issue (Attachment D, throughout);
- Explain that MISO, following the workgroup process, implemented its finalized process on October 1, 2023 for reviewing transmission impacts caused by DER projects, including the trigger that MISO would use for its review (Attachment D, page 25);
- Note that by November 2023 DER applications at three substations were the subjects of MISO studies (Attachment D, page 26);
- Note that the trigger for the MISO review is where aggregate DER at a substation exceeds substation peak load by at least 1 MW (Attachment D, pages 26, 34);
- Disclose that the MISO cost is $60,000 per study per substation (Attachment D, pages 26, 27, 31, 33, 36, 38, 40);
- Explain the MISO quarterly cadence of its review and study of DER applications (Attachment D, pages 26, 27, 31, 33, 36, 38, 40);
- Explain when payments are due to Xcel Energy when a MISO study is triggered (Attachment D, page 52, 53, 54); and
- Disclose that the first MISO study for a DER project calculated that the transmission upgrade costs would be $8 million if the project were to move forward (Attachment D, pages 26, 27, 36, 38, 40).

2. Internal Transmission Studies

In the weeks just prior to the issuance of the Notice, Xcel Energy's practice regarding internal transmission studies was discussed in the November 1, 2024 Distributed

Generation Working Group (DGWG), Xcel Energy held a stakeholder discussion on December 2, 2024, and Xcel Energy and Joint Parties submitted reports on these practices to the DGWG on December 13, 2024.[11] Prior to this, Xcel Energy extensively discussed the ITS also at several workgroup meetings beginning in August 2023 and in several filings with the Commission.

The Company's ITS follows the process and timelines specified in MN DIP 4.3.6, 4.3.7 and 4.3.8 for transmission SIS, these provisions are provided below:

> 4.3.6 In instances where the System Impact Study shows potential for Transmission System adverse system impacts… the Area EPS Operator shall coordinate with the appropriate Transmission Provider to have the necessary studies completed to determine if the DER causes any adverse transmission impacts.
>
> 4.3.7 In order to remain in consideration for interconnection, an Interconnection Customer must return the executed Transmission System impact study agreement within fifteen (15) Business Days.
>
> 4.3.8 A Transmission System impact study, if required, shall be completed and the results transmitted to the Interconnection Customer in as timely a manner as possible after the transmission system impact study agreement is signed by the Parties. The Area EPS Operator shall be responsible for coordination with the Transmission Provider as needed. Affected Systems shall participate in the study and provide all information necessary to prepare the study.

There is a potential for transmission system adverse system impacts when either the MISO trigger or the Xcel Energy trigger for further review are met. MN DIP 4.3.6 requires further study in these circumstances. The Company had similar concerns with MISO regarding the rapidly growing amount of interconnected DER within our system and its impacts on the transmission system. While we participated in 2022 in the MISO IPWG process to develop the MISO DER AFS, it became clear to us that there may be a gap in the MISO process that may not capture all potential adverse transmission impacts that could be experienced on Xcel Energy's transmission system. Further, under the NERC regulations discussed above, a study needs to be performed when the proposed DER would back-feed on to the transmission system. Therefore, to protect the safety and reliability of the Xcel Energy system, and to

[11] Commission Staff filed these two reports in this Docket on February 11, 2025. Joint Parties included Nokomis Energy LLC, Enterprise Energy, Novel Energy Solutions LLC, and Sunrise Energy Ventures LLC.

follow NERC requirements, we developed the internal study process and then implemented the ITS in October 2023.

The Company conducts an ITS when the aggregate DER exceeds the substation DML (but is less than the substation peak load which is the MISO study trigger). In addition, the substation must have more than 750 kW of aggregated DER. If the Company's ITS study trigger is met, then Xcel Energy's Transmission Planning group conducts one ITS in each quarter across the whole Xcel Energy transmission system in Minnesota. The reasons for the quarterly cadence are discussed below. If developers have multiple projects that require an ITS, they only need to pay one study fee of $33,000.[12] This is the total cost and fee for an ITS study, regardless of the number of projects in that study. So, if 10 projects participate in a single study, the net cost per project participating in the study is $3,300. In the event that more than one project participates in a single ITS study and no project cancels before the study starts, the Company provides a refund so that the cost of the study is effectively evenly shared among the projects that participate in the ITS study.

Projects flagged for an ITS may wait until the completed distribution SIS results are available until they decide whether to move forward with the ITS or withdraw. This gives the developer practical flexibility. For example, they may wait to see the results of the distribution SIS study, which potentially could show needed distribution upgrades of $1 million. If so, the developer may decide the project is not financeable and therefore has no need for a transmission analysis.

The Company allows developers 23 Business Days (15 Business Days defined in MN DIP plus an automatic 8 Business Day extension) to sign the Transmission SIS Agreement for the ITS and fund the study. An example Transmission SIS Agreement applicable to the ITS is attached as Attachment E. After the ITS study begins, Xcel Energy completes the ITS within 90 days, which is reasonable and timely for a complex study. The Company may use cluster studies for the ITS, which allows the processing of more projects per quarterly study. The Transmission SIS Agreement also clearly provides for a cluster study (see the last page of Attachment E). The critique of the Joint Parties regarding the lack of cluster studies for ITS is therefore not correct (December 13, 2024 Report, p. 1).

The JSA has asserted without support that the ITS will apply to 90 percent of the currently pending interconnection queue (December 13, 2024 Letter, p. 2). The Joint Parties go even bolder by asserting without support that "nearly all" of the applications in the queue will be subject to the ITS (December 13, 2024 Report, p. 1).

[12] The study fee will be reduced to $27,000 starting April 1 with the Q2 2025 Study.

Out of the 242 substations within the Company's Minnesota service territory, approximately 7 percent of substations have been subject to an ITS, and approximately 17 percent of substations have been subject to a MISO study. In total, this is 24 percent of all substations. For comparison, this number can be correlated to the total amount of substations that are currently capacity constrained, which is roughly 25 percent of all substations. Based on this data, the conclusion is that in certain areas of high DER penetration, it is likely that a transmission study will be warranted. But from a system-wide perspective, the number of substations requiring a transmission study is relatively small. Additionally, we note that the amount of aggregate DER is at or above the DML on 18 percent of the Company's feeders.

The Company has regularly informed developers about the ITS study processes for DER interconnection, both before and after they were implemented. These communications took place through various filings in Docket Nos. 13-867 and 16-521 as well as several workgroups referenced in these filings. Excerpts in Attachment D pertaining to the ITS include the following:

- November 28, 2023 filing of DER workgroup minutes for meeting of August 9, 2023, informing developers and interested parties of the ITS set to begin on October 1, 2023 for applications beginning System Impact Studies on or after September 1, 2023. (Attachment D, pages 31 and 32).
- November 14, 2023 filing of Xcel Energy responses to IRs issued by Commission Staff on the ITS studies. These responses address the issues of Xcel Energy being a Transmission Provider[13], why the MISO study process is insufficient, explains compliance with MN DIP 4.3.6, and explains why the quarterly review process complies with MN DIP 4.3.8. (Attachment D, pages 16-19, and 21-22).
- In the November 15, 2023 DER Quarterly Compliance Filing, noted that on September 1, 2023 Xcel Energy had implemented the ITS which is independent of the MISO Transmission Study process. This filing also explained that the ITS was explained at the DER workgroup session on August 9, 2023, that this applies where aggregate DER exceeds substation DML but is less than peak load, and that those meeting this criteria would not be send to MISO for review. (Attachment D, pages 25 and 27).
- In the March 1, 2024 DER Quarterly Compliance Filing, re-iterated the nature of the ITS studies. (Attachment D, page 36).

[13] This filing refutes the JSA contention that JSA had no notice prior to the December 2, 2024 stakeholder meeting that Xcel Energy considers itself to be a Transmission Provider. Similarly, this filing refutes the related JSA assertion that prior to December 2, 2024 that Xcel Energy did not consider itself to be a Transmission Provider. See, JSA December 13, 2024 Letter.

- In the May 15, 2024 DER Annual Report, re-iterated the nature of the ITS studies. (Attachment D, page 38).
- In the August 15, 2024 DER Quarterly Compliance Filing, re-iterated the nature of the ITS studies. (Attachment D, page 40).
- In the September 19, 2024 filing of the minutes of the May 15, 2024 workgroup, re-iterated the nature of the ITS studies and provided a cost update. (Attachment D, pages 45 and 46).
- In the December 19, 2024 filing of the minutes of the September 4, 2024 workgroup, re-iterated the nature of the ITS studies and provided updates on this process. (Attachment D, page 52 and 53).

C. How are these transmission studies different than MISO's transmission studies?

- What do the Xcel transmission studies provide that the MISO studies do not?
- Does that difference necessitate a separate transmission study process?
- If there are safety and reliability concerns, please offer a greater technical explanation using data and examples if possible.

The transmission system has federal standards and regulations, enforced by NERC, that require the transmission system to be within its system operating limits both in the Transmission Planning realm and the Operations realm. Firstly, Transmission Planning standards such as NERC TPL-001-5[14] require conducting yearly studies in order to ensure that voltage and thermal limits on the system are maintained for a variety of outage scenarios. The ITS performs this same type of analysis to determine risks on the transmission system. Transmission Planning's purpose is to monitor and study changes to the transmission system so that the operators of the grid can maintain all system limits without serious consequences.

If ITS studies are not performed, transmission operators may be put in a position where they cannot mitigate voltage deviations or thermal overloads caused in part by DER generation. This could lead to significant compliance risk or risk to the transmission system. Transmission Operations have multiple standards enforced by NERC which would pertain to maintaining the system within acceptable limits, such as NERC TOP-001 and NERC TOP-002.

Lastly, our Transmission Operations group has observed real-time concerns. We suspect that in multiple locations, significant DER penetration during summer loading causes low voltage on the transmission system as a result of DER absorbing VAR's

[14] Available at: https://www.nerc.com/pa/Stand/Reliability%20Standards/TPL-001-5.pdf

and pulling down area voltage. In these situations, unless there are elements which can be adjusted or identified in studies and resolved before DER interconnection, system operators may not have any option to change the area voltage.

The Xcel Energy ITS studies the DER at different levels than what is studied in the MISO transmission analysis. For the ITS, the level of DER must be greater than the substation DML. The MISO transmission studies look at DER levels greater than the substation peak load. The ITS ensures that the Company does not see issues on the transmission system for DER interconnections that do not trigger a MISO review. If MISO would have chosen to study all DER at the DML threshold, then there would be only one study process. However, MISO decided to use the threshold of peak load based on the desire for "simplicity and transparency." MISO did acknowledge that DER penetrations other than peak load can be studied by individual Transmission Owners.[15]

From a safety and reliability perspective and per NERC requirements, transmission system impact studies are needed when there is reverse flow from the distribution system onto the transmission network. Under the MISO screening and study trigger, there is a gap in performing necessary studies. MISO's DER AFS is only triggered when DER would exceed peak loading scenarios. But there is an amount of time when the feeders/distribution substation are not at system peak. This peak occurs once per year. For the remainder of the year, DER production can have a material impact on the safety and reliability of the system. For example, at DML times, solar may be at full output. This means that there can be substantial back-feed on to the transmission network. Accordingly, when DER exceeds DML but is less than peak substation load, we need to assess under an ITS the potential impact of DER on the safety and reliability of transmission system under this scenario. The ITS applies to the gap between the DML and peak load scenarios, and this gap needs to be studied from a safety, reliability, and NERC compliance perspective. This explanation is consistent with how we have answered prior Staff information requests (IRs) filed on November 14, 2023, which are included in Attachment D.

The MISO trigger for further review is when the reverse flow is identified to exceed peak substation load. The Company's ITS is triggered when reverse flow exceeds the

[15] See, for example, the MISO IPWG PowerPoint presentation of June 6, 2022, at page 5, which states: "*MISO proposes to use standardized screening for simplicity and transparency, consistent with other Affected Systems practices, when considering DER impacts on the MISO functional control transmission system. TOs [(Transmission Owners)] would retain the right to perform state-jurisdictional transmission studies, per the applicable Relavent Electric Retail Regulatory Authority (RERRA) rules.*" This presentation is available at: available at: https://cdn.misoenergy.org/20220606%20IPWG%20Item%2005%20DER%20Interconnection624982.pdf)

substation DML. In either case, reverse flow to the substation would show potential for transmission system adverse system impacts for both safety and reliability and therefore creates a need for the studies in both scenarios. Under either case, NERC requires a study. Further, as explained above, the Company has identified instances of the transmission system being out of standard due to DER interconnections.

The MISO and Xcel Energy transmission studies are non-duplicative, and they both would determine, under different conditions, if the DER causes any adverse transmission system impacts. If a project triggers MISO screening, regardless of whether a full MISO study will be needed, the project would not be expected to be subject to an ITS.

Table 1 below shows some of the differences between MISO analysis and Xcel Energy's analysis.

Table 1: Differences Between MISO and Xcel Energy Study

	MISO DER AFS	Xcel Energy ITS
Where	Aggregate DER exceeds substation peak load by at least 1 MW	For Substations with 750 kW or more of interconnected DER, aggregate DER exceeds substation DML (but MISO trigger has not been met).
When	Quarterly as scheduled by MISO[16]. Each substation studied separately, and the study fee applies per substation being studied.	Quarterly. All substations are studied together, and the study fee remains the same regardless of the number of projects participating. The fee is spread out to all participating projects in the study.
Why	Ensure reliability and deliverability of the regional transmission system.	Ensure reliability of Xcel Energy's transmission system, specifically for thermal or voltage issues. Ensures compliance with NERC regulations.

[16] https://www.misoenergy.org/planning/resource-utilization/distribution/#t=10&p=0&s=FileName&sd=desc

D. Are Xcel Energy's transmission studies permissible under the MN DIP? Address specifically, if Xcel Energy is a Transmission Owner or Transmission Provider and whether the internal transmission studies are Affected System Studies.

- If the transmission studies aren't permissible should the MN DIP be modified to allow for them to be permissible?
- If the transmission studies are permissible, should the MN DIP be modified to add more detail or guidelines to that process? What would the specific edits be and why?

The Company has provided extensive discussion above how the ITS is not only permitted under MN DIP, but also required under MN DIP. The ITS conforms with all MN DIP provisions regarding transmission studies. We also explained in detail that since Xcel Energy owns and operates substations and other transmission facilities, it qualifies under the MN DIP definitions as being both a Transmission Owner and a Transmission Provider.

The Company believes that the MN DIP is sufficiently clear regarding the transmission SIS process and does not require additional details or guidelines. Each Transmission Provider should be able to use their engineering judgment to create a process and technical requirements that are appropriate for their specific system. Here, the two Transmission Providers (MISO and the Company) have coordinated so that there is no redundancy in their study process and no gap between them. This aligns with MN DIP 5.13 that requires this type of coordination.

We describe below that the ITS is an Affected System Impact Study and respond to other parties' previous arguments that attempt to show that the ITS does not align with the MN DIP.

1. The Xcel Energy Transmission System is an Affected System

The Notice requested comment on the issue of whether the ITS is an Affected System Study under MN DIP. The MN DIP does not use the term "Affected System Study." But, the MN DIP definition of "Affected System" includes the following: "… *Transmission Owner's Transmission System, or Transmission System connected generation which may be affected by the proposed interconnection."* Here, the ITS is for study of the Transmission Owner's Transmission System and how this would be affected by the proposed DER. Also, the ITS studies the effects that the proposed DER would have on the Transmission System connected generation. Therefore, for both of these reasons the ITS is an Affected System study.

2. The Arguments of the Joint Parties on the ITS Not Being Allowed Are Incorrect

The Joint Parties have raised several arguments which attempt to show that the ITS does not align with MN DIP or otherwise is not allowed. The Company addresses these below to the extent that they are not addressed elsewhere in this filing.

a. Improper Assertions of Several Facts

The Joint Parties have stated that Xcel Energy previously informed the Commission that Xcel Energy "… would rely solely on MISO's screening criteria and study processes", that the Commission had ordered Xcel Energy not to undertake without a full comment period essentially the same process that Xcel Energy has now implemented, and that Xcel Energy's process is not written down (December 13, 2024 Report, p. 1). All these assertions are without merit.

The Joint Parties provide no support for their assertion that Xcel Energy communicated that it would rely solely on MISO's screening criteria and not conduct its own studies. The Company does not believe that the assertion of the Joint Parties is correct. The Company has no recollection of having made any such representation, and after a diligent search cannot find any references in the Commission's e-dockets system showing such representation.

The Joint Parties also provide no support for their assertion that the Commission had ordered Xcel Energy not to undertake something like the ITS without a full comment period. They cite to the Commission's March 31, 2022 Order, but this Order only set up a comment period for the MISO ASIS Agreement, and did not state that a comment period would apply to other types of transmission studies.

The Joint Parties also state that the ITS process is not written down. However, this process has been described in writing in many Commission filings as shown above.

b. Improper Assertions on Not Using Daytime Minimum Load as a Trigger for the ITS

The Joint Parties also argue that Xcel Energy had committed in its March 4, 2022 letter filed in Docket No. 16-521 that it would not use a daytime minimum load threshold as a trigger for a transmission study (December 13, 2024 Report, pp. 2-3). This falsely conveys what we had said.

The comments in that letter were clearly solely applicable to the MISO ad hoc process, which is not at issue here. The Company stated in that letter:

> Given this guidance, the Company will begin to implement the MISO ad hoc process as discussed at the February 25, 2022 DGWG meeting. For determining the potential of adverse transmission system impacts, under the MISO ad hoc process we intend to use two thresholds for initiating the study: (1) the threshold that MISO discussed at the DGWG meeting – namely, where the proposed DER may provide new or increased backflow onto the transmission system during peak load at a particular substation, and (2) where we may otherwise determine that the DER shows potential for adverse transmission system impacts. We clarify that under the ad hoc process, we will not use as a threshold where the DER requires a new feeder, unless one of the above thresholds was also met. And, we will not send a Notice to MISO under its ad hoc process in situations where a DER would exceed Daytime Minimum Load unless one of the above thresholds was also met.

The Company has kept to these representations. MISO no longer uses its ad hoc process, and the Company's ITS is not part of the MISO ad hoc process. The above provisions from this letter do not restrict in any way how the ITS study is to be conducted, nor what the trigger would be for this type of study.

c. Conflating MN DIP Changes to Implement the MISO ASIS Agreement with No Changes Required to Implement the ITS

Additionally, the Joint Parties point to the Company's March 21, 2022 and March 31, 2022 filings where we had proposed MN DIP changes to harmonize with the MISO ASIS Agreement (December 13, 2024 Report, p. 3). They argue that the Company had proposed these changes to better align with the transmission study process. They imply that the Company's proposals to change the MN DIP to align with the MISO ASIS Agreement would be applicable to the ITS and to any type of transmission study – not just under the MISO ASIS process. However, again, our letters are specific to the MISO ASIS agreement only. The Company sees no need to change the MN DIP to implement the ITS process or the current MISO DER AFS process.

The Company does note that we stated as follows in our March 21, 2022 filing:

> While MN DIP 4.3.6 and 4.3.7 align with starting the DER System Impact Study (SIS) before determining whether transmission

> upgrades are needed and only then entering into a TSIS Agreement, paragraph 8.0 of the DER SIS Agreement (at tariff sheet 10-233) provides that the estimated costs for transmission system impact study are due upon signing of the DER SIS Agreement. This would be before the timeframe to identify the need for transmission study in above provisions.

This issue about MN DIP inconsistency has been resolved without changing the MN DIP. The solution was to have a separate Distribution SIS Agreement and Transmission SIS Agreement. Also, the Transmission SIS Agreement is needed only after the need for this study is established as part of the Distribution SIS. The Distribution SIS Agreement is signed first, and the Distribution SIS is then started, and during this study the need for a Transmission SIS can be identified. If so, then a Transmission SIS Agreement is executed. We have attached as Attachment E an example of a Transmission SIS Agreement for an ITS. The MN DIP process is working just fine and does not need to be changed.

d. Substation Queue Concerns

The Joint Parties also argue that under MN DIP there is a queue only by feeder (December 13, 2024 Report, p. 6). Since under the ITS there is a queue by substation, they argue that this conflicts with MN DIP.

Under MN DIP, there are queues by feeder and by substation. MN DIP 1.8.3 states:

> The Area EPS Operator shall maintain a single, administrative queue and may manage the queue by geographical region (i.e. feeder, substation, etc.) This administrative queue shall be used to address Interconnection Customer inquiries about the queue process. If the Area EPS Operator and the Interconnection Customer(s) agree, Interconnection Applications may be studied in clusters for the purpose of the system impact study; otherwise, they will be studied serially.

Consistent with this, and consistent with MN DIP 1.8.4, the Company provides on its website a monthly queue report that shows the date each application has been deemed complete, and with sorting ability to show queue position by feeder or by substation. There are several areas where more than one feeder connects to the same substation. If a DER application on one feeder has triggered a substation review or transmission study, by necessity an application on another feeder connected to the same substation must wait for its turn in queue before being studied if they are not part of the same

cluster study. This is consistent with how MN DIP has been implemented from day one. The ITS process has not changed this.

Similarly, the Joint Parties argue that the Commission's March 31, 2022 Order ended the "on hold" process, and that with our quarterly cadence the ITS creates a new "on hold" process (December 13, 2024 Report, p. 7). The Commission's March 2022 Order did not change the queue process. The Joint Parties only provide select language from the Commission's Order. They have not included pertinent language to put their quoted language in context. The March 2022 Order (p. 3) detailed the "on hold" process in place before the issuance of that order whereby Xcel Energy processed the queue sequentially and had frequently placed projects, of all sizes, "on-hold" until the interconnection review of the project ahead in queue was complete and either had a signed interconnection agreement or has been withdrawn. But, interconnections of 40 kilowatts (kW) or less could continue moving forward through the process in parallel (parallel review) if doing so would not materially affect projects ahead in queue.

The Commission in the March 2022 Order (p. 4) adjusted the "on hold" process so that in areas without a capacity constraint the next in queue "Fast Track" project above 40 kW would be studied in parallel with those that are ahead-in-queue such that once the project ahead-in-queue in a non-constrained area has a signed Facilities Study Agreement the next project above 40 kW can begin a System Impact Study. This order did not change the approach of needing a signed interconnection agreement for the ahead-in-queue project before starting the System Impact Study for the next in queue in constrained areas. The Facilities Study Agreement is under MN DIP 4.4 (and at MN DIP Attachment 7). The Facilities Study follows the System Impact Study. The System Impact Study (at MN DIP 4.3 and at MN DIP Attachment 6) shows what modifications to the network are needed to accommodate the proposed DER Agreement. The Facilities Study helps to scope an indicative cost estimate for this work. After the Facilities Study is complete, an Interconnection Agreement can be entered into that reflects the indicative cost estimate. The Commission specifically stated (p. 4): "In making this change, the Commission understands that projects may still spend a significant time in queue …" The ordering points from this order on this issue as consistent with this.

The ITS process does not conflict with the Commission's March 2022 Order on this "on hold" issue. The ITS is conducted as part of the transmission System Impact Study and is conducted in capacity constrained areas. Under the Commission's March 2022 Order, the next in queue is not to be studied until the System Impact Studies and Facilities Studies are complete and the ahead-in-

queue project has a signed Interconnection Agreement. This process remains unchanged under the ITS.

E. Based on the information derived from the two reports provided to the DGWG on this topic:

- Is the exact timing and quarterly processing of the Xcel Energy transmission studies open to being modified? Would it be beneficial to include stakeholder input?
- Is there any information that deserves further investigation or exploration beyond what was discussed in the reports that the Commission should consider?

When the timing and cadence of Xcel Energy's ITS is considered, it is important to keep in mind that we conduct each quarter one ITS at the same time for all DER projects that meet the study trigger to determine the cumulative impact on Xcel Energy's Minnesota transmission system. There are several practical reasons why the quarterly study cadence is the most appropriate. This approach allows the prior quarter ITS to be completed before the next ITS is started and reduces the number of studies that are required. Further, since each ITS studies all of the Xcel Energy Minnesota substations, the Company needs to see the results of the prior study, including which projects have triggered needed upgrades and determine whether these projects will proceed with these upgrades, before starting the next study. In addition, since all applicable projects are included in one quarterly ITS, the study cost per project is lower because the study fee is shared by all participating DER projects.

The Company provides below a table showing the current and upcoming ITS schedule.

Table 2: Upcoming ITS Schedule

Xcel Energy ITS Milestones	**Q4-2024**	**Q1**	**Q2**	**Q3**	**Q4**
ITS Quarter Opens	10/1/2024	1/1/2025	4/1/2025	7/1/2025	10/1/2025
Quarterly ITS Cutoff	12/20/2024	3/20/2025	6/20/2025	9/20/2025	12/20/2025
True Ups Begin	12/21/2024	3/21/2025	6/21/2025	9/21/2025	12/21/2025
Transmission Study Begins	1/1/2025	4/1/2025	7/1/2025	10/1/2025	1/1/2026
Study Results Provided	3/1/2025	6/1/2025	9/1/2026	12/1/2025	3/1/2026

*Signed Agreements and Payment due 15 Business days + 8 Business Day automatic extension from date agreements are sent to developer.

We do not believe that a more frequent study cadence would be practical or beneficial to DER projects. The quarterly cadence for the ITS is most practical and also follows the MISO approach with its quarterly cadence.

The Company notes that the ITS process is still in its infancy. The Company suggests that it be allowed to gain some real-world experience with examining the results of the ITS studies for some period so as to have a better-informed base before engaging in further discussions to modify the process. Evaluation of these study results may reinforce the need for the current ITS process or show potential for other viable approaches. Also, the Company suggests that any participant seeking changes to the ITS should be productive and come forward with a realistic alternative to the current ITS that would also comply with NERC standards. Just saying "No" to the ITS would not likely lead to a productive discussion. To be clear, the Company is open to feedback and has discussed with stakeholders at the DER quarterly workgroups their questions and concerns. We believe this dialogue should continue in the DER workgroup process, including discussion on the exact timing and quarterly cadence of the ITS.

F. How should the Commission consider impacts of Xcel Energy's transmission studies on interconnection-related or state-goal related programs; such as LMI CSG Program?

One of the main purposes of the MN DIP is to ensure efficient, safe and reliable DER interconnection and to be compliant with applicable standards. This highly technical interconnection process is independent from any programs that are established by the Legislature to promote state renewable goals, such as the Solar*Rewards program, the Legacy Community Solar Garden (CSG) program, and the Low- and Moderate Income (LMI) Accessible CSG program. The MN DIP should remain separate and independent from these programs. Further, Minn. Stat. § 26B.1611 specifies the need for generic interconnection standards, and does not indicate that different interconnection standards should be used depending upon the solar program under which the DER seeks interconnection. The CSG statute also specifies that the Commission must establish uniform standards, fees, and processes for the interconnection of CSGs. (Minn. Stat. § 216B.164, Subd. 1 (e)(2), which applies to both the Legacy CSG program, and also applies to the LMI CSG program per Minn. Stat. § 216B.164, Subd. 3(b).). The standards that apply to the interconnection process are the MN DIP standards, and also include the NERC standards, and these standards apply to all DER applications regardless of program.

G. How should the Commission respond to JSA's request of the following?

- Should Xcel's internal transmission study be stayed until the Commission grants approval?
- Should the Commission open an investigation into Xcel's internal transmission studies and refer the matter to the Distributed Generation Working Group (DGWG)?

As described above, Xcel Energy's ITS conforms with the MN DIP and is necessary to ensure that there are no adverse transmission impacts from DER interconnection. The ITS is also required to comply with NERC requirements. The technical requirements regarding ITS, such as the trigger threshold, are within Xcel Energy's engineering judgment and the ITS does not require Commission approval. The ITS complies with MN DIP and applicable state law. Further, staying the current ITS process would result in either violating NERC requirements or putting projects on hold until an alternative NERC-compliant solution to protect the transmission system is created. Therefore, there are no reasonable grounds to open an investigation on the ITS, to refer the ITS to the DGWG, or to stay the current ITS process.

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

We do not have any additional issues or concerns.

CONCLUSION

The Company believes there are no reasonable grounds to open an investigation on Xcel Energy's ITS process as it is clearly allowed by the MN DIP and state law to ensure the safety and reliability of the transmission system. The ITS process also aligns with NERC requirements. The technical requirements of the transmission SIS are within the Transmission Operator's engineering judgement and do not require approval by the Commission. Ceasing the current ITS process would result in either violating NERC requirements or putting projects on hold until an alternative NERC-compliant solution to protect the transmission system is created.

Dated: March 13, 2025

Northern States Power Company

A. Introduction

1. **Title:** **Facility Interconnection Studies**

2. **Number:** FAC-002-4

3. **Purpose:** To study the impact of interconnecting new or changed Facilities on the Bulk Electric System.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Planning Coordinator

   4.1.2. Transmission Planner

   4.1.3. Transmission Owner

   4.1.4. Distribution Provider

   4.1.5. Generator Owner

   4.1.6. Applicable Generator Owner

   4.1.6.1. Generator Owner with a fully executed Agreement to conduct a study on the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission system.

5. **Effective Date:** See Implementation Plan for Project 2020-05.

B. Requirements and Measures

R1. Each Transmission Planner and each Planning Coordinator shall study the reliability impact of: (i) interconnecting new generation, transmission, or electricity end-user Facilities and (ii) existing interconnections of generation, transmission, or electricity end-user Facilities seeking to make a qualified change as defined by the Planning Coordinator under Requirement R6. The following shall be studied: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. The reliability impact of the new interconnection, or existing interconnection seeking to make a qualified change as defined by the Planning Coordinator under Requirement R6, on affected system(s);

1.2. Adherence to applicable NERC Reliability Standards; regional and Transmission Owner planning criteria; and Facility interconnection requirements;

1.3. Steady-state, short-circuit, and dynamics studies, as necessary, to evaluate system performance under both normal and contingency conditions; and

1.4. Study assumptions, system performance, alternatives considered, and coordinated recommendations. While these studies may be performed independently, the results shall be evaluated and coordinated by the entities involved.

M1. Each Transmission Planner or each Planning Coordinator shall have evidence (such as study reports, including documentation of reliability issues) that it met all requirements in Requirement R1.

R2. Each Generator Owner seeking to interconnect new generation Facilities, or existing interconnections of generation Facilities seeking to make a qualified change as defined by the Planning Coordinator under Requirement R6, shall coordinate and cooperate on studies with its Transmission Planner or Planning Coordinator, including but not limited to the provision of data as described in R1, Parts 1.1-1.4. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M2. Each Generator Owner shall have evidence (such as documents containing the data provided in response to the requests of the Transmission Planner or Planning Coordinator) that it met all requirements in Requirement R2.

R3. Each Transmission Owner and each Distribution Provider seeking to interconnect new transmission Facilities or electricity end-user Facilities, or existing interconnections of transmission Facilities or electricity end-user Facilities seeking to make a qualified change as defined by the Planning Coordinator under Requirement R6, shall coordinate and cooperate on studies with its Transmission Planner or Planning Coordinator, including but not limited to the provision of data as described in R1, Parts 1.1-1.4. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M3. Each Transmission Owner and each Distribution Provider shall have evidence (such as documents containing the data provided in response to the requests of the

Transmission Planner or Planning Coordinator) that it met all requirements in Requirement R3.

R4. Each Transmission Owner shall coordinate and cooperate with its Transmission Planner or Planning Coordinator on studies regarding requested new or existing interconnections seeking to make a qualified change as defined by the Planning Coordinator under Requirement R6, to its Facilities, including but not limited to the provision of data as described in R1, Parts 1.1-1.4. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M4. Each Transmission Owner shall have evidence (such as documents containing the data provided in response to the requests of the Transmission Planner or Planning Coordinator) that it met all requirements in Requirement R4.

R5. Each applicable Generator Owner shall coordinate and cooperate with its Transmission Planner or Planning Coordinator on studies regarding requested interconnections to its Facilities, including but not limited to the provision of data as described in R1, Parts 1.1-1.4. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M5. Each applicable Generator Owner shall have evidence (such as documents containing the data provided in response to the requests of the Transmission Planner or Planning Coordinator) that it met all requirements in Requirement R5.

R6. Each Planning Coordinator shall maintain a publicly available definition of qualified change for the purposes of facility interconnection. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M6. Each Planning Coordinator shall have evidence that it has maintained a publicly available definition of qualified change.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: "Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention: The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The Planning Coordinator, Transmission Planner, Transmission Owner, Distribution Provider, Generator Owner and applicable Generator Owner shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

The responsible entities shall retain documentation as evidence for three years.

If a responsible entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.

The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Enforcement Program: As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	Long-term Planning	Medium	The Transmission Planner or Planning Coordinator studied the reliability impact of: (i) interconnecting new generation, transmission, or electricity end-user Facilities, and (ii) existing interconnections of generation, transmission, or electricity end-user Facilities seeking to make a qualified change as defined by the Planning Coordinator under Requirement R6, but failed to study one of the Parts (R1, 1.1-1.4).	The Transmission Planner or Planning Coordinator studied the reliability impact of: (i) interconnecting new generation, transmission, or electricity end-user Facilities, and (ii) existing interconnections of generation, transmission, or electricity end-user Facilities seeking to make a qualified change as defined by the Planning Coordinator under Requirement R6, but failed to study two of the Parts (R1, 1.1-1.4).	The Transmission Planner or Planning Coordinator studied the reliability impact of: (i) interconnecting new generation, transmission, or electricity end-user Facilities, and (ii) existing interconnections of generation, transmission, or electricity end-user Facilities seeking to make a qualified change as defined by the Planning Coordinator under Requirement R6, but failed to study three of the Parts (R1, 1.1-1.4).	The Transmission Planner or Planning Coordinator failed to study the reliability impact of: interconnecting new generation, transmission, or electricity end-user Facilities, and (ii) existing interconnections of, generation, transmission, or electricity end-user Facilities seeking to make a qualified change as defined by the Planning Coordinator under Requirement R6.
R2.	Long-term Planning	Medium	The Generator Owner seeking to interconnect new generation Facilities,	The Generator Owner seeking to interconnect new generation Facilities,	The Generator Owner seeking to interconnect new generation Facilities,	The Generator Owner seeking to interconnect new generation Facilities,

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			or existing interconnections of generation Facilities seeking to make a qualified change as defined by the Planning Coordinator under Requirement R6, coordinated and cooperated on studies with its Transmission Planner or Planning Coordinator, but failed to provide data necessary to perform studies as described in one of the Parts (R1, 1.1-1.4).	or existing interconnections of generation Facilities seeking to make a qualified change as defined by the Planning Coordinator under Requirement R6, coordinated and cooperated on studies with its Transmission Planner or Planning Coordinator, but failed to provide data necessary to perform studies as described in two of the Parts (R1, 1.1-1.4).	or existing interconnections of generation Facilities seeking to make a qualified change as defined by the Planning Coordinator under Requirement R6, coordinated and cooperated on studies with its Transmission Planner or Planning Coordinator, but failed to provide data necessary to perform studies as described in three of the Parts (R1, 1.1-1.4).	or existing interconnections of generation Facilities seeking to make a qualified change as defined by the Planning Coordinator under Requirement R6, failed to coordinate and cooperate on studies with its Transmission Planner or Planning Coordinator.
R3.	Long-term Planning	Medium	The Transmission Owner or Distribution Provider seeking to interconnect new transmission Facilities or electricity end-user Facilities, or existing interconnections of transmission Facilities	The Transmission Owner, or Distribution Provider seeking to interconnect new transmission Facilities or electricity end-user Facilities, or existing interconnections of transmission Facilities	The Transmission Owner or Distribution Provider seeking to interconnect new transmission Facilities or electricity end-user Facilities, or existing interconnections of transmission Facilities	The Transmission Owner, or Distribution Provider seeking to interconnect new transmission Facilities or electricity end-user Facilities, or existing interconnections of transmission Facilities

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			seeking to make a qualified change as defined by the Planning Coordinator under Requirement R6, or electricity end-user Facilities, coordinated and cooperated on studies with its Transmission Planner or Planning Coordinator, but failed to provide data necessary to perform studies as described in one of the Parts (R1, 1.1-1.4).	seeking to make a qualified change as defined by the Planning Coordinator under Requirement R6, or electricity end-user Facilities, coordinated and cooperated on studies with its Transmission Planner or Planning Coordinator, but failed to provide data necessary to perform studies as described in two of the Parts (R1, 1.1-1.4).	seeking to make a qualified change as defined by the Planning Coordinator under Requirement R6, or electricity end-user Facilities, coordinated and cooperated on studies with its Transmission Planner or Planning Coordinator, but failed to provide data necessary to perform studies as described in three of the Parts (R1, 1.1-1.4).	seeking to make a qualified change as defined by the Planning Coordinator under Requirement R6, or electricity end-user Facilities, failed to coordinate and cooperate on studies with its Transmission Planner or Planning Coordinator.
R4.	Long-term Planning	Medium	The Transmission Owner coordinated and cooperated on studies with its Transmission Planner or Planning Coordinator regarding requested new or existing interconnections	The Transmission Owner coordinated and cooperated on studies with its Transmission Planner or Planning Coordinator regarding requested new or existing interconnections	The Transmission Owner coordinated and cooperated on studies with its Transmission Planner or Planning Coordinator regarding requested new or existing interconnections	The Transmission Owner failed to coordinate and cooperate on studies with its Transmission Planner or Planning Coordinator regarding requested new or existing interconnections

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			seeking to make a qualified change as defined by the Planning Coordinator under Requirement R6to its Facilities, but failed to provide data necessary to perform studies as described in one of the Parts (R1, 1.1-1.4).	seeking to make a qualified change as defined by the Planning Coordinator under Requirement R6to its Facilities, but failed to provide data necessary to perform studies as described in two of the Parts (R1, 1.1-1.4).	seeking to make a qualified change as defined by the Planning Coordinator under Requirement R6to its Facilities, but failed to provide data necessary to perform studies as described in three of the Parts (R1, 1.1-1.4).	seeking to make a qualified change as defined by the Planning Coordinator under Requirement R6to its Facilities.
R5.	Long-term Planning	Medium	The applicable Generator Owner coordinated and cooperated on studies with its Transmission Planner or Planning Coordinator regarding requested interconnections to its Facilities, but failed to provide data necessary to perform studies as described in one of the Parts (R1, 1.1-1.4).	The applicable Generator Owner coordinated and cooperated on studies with its Transmission Planner or Planning Coordinator regarding requested interconnections to its Facilities, but failed to provide data necessary to perform studies as described in two of the Parts (R1, 1.1-1.4).	The applicable Generator Owner coordinated and cooperated on studies with its Transmission Planner or Planning Coordinator regarding requested interconnections to its Facilities, but failed to provide data necessary to perform studies as described in three of the Parts (R1, 1.1-1.4).	The applicable Generator Owner failed to coordinate and cooperate on studies with its Transmission Planner or Planning Coordinator regarding requested interconnections to its Facilities.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R6.	Long-term Planning	Lower	N/A	N/A	N/A	The Planning Coordinator did not maintain a publicly available definition of qualified change for the purposes of facility interconnection.

D. Regional Variances

None.

E. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	January 13, 2006	Removed duplication of "Regional Reliability Organizations(s).	Errata
1	August 5, 2010	Modified to address Order No. 693 Directives contained in paragraph 693. Adopted by the NERC Board of Trustees.	Revised
1	February 7, 2013	R2 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.	
1	November 21, 2013	R2 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	
2		Revisions to implement the recommendations of the FAC Five-Year Review Team.	Revision under Project 2010-02
2	August 14, 2014	Adopted by the Board of Trustees.	
2	November 6, 2014	FERC letter order issued approving FAC-002-2.	
3	February 6, 2020	Adopted by NERC Board of Trustees.	Revisions under Project 2017-07
4	May 12, 2022	Adopted by NERC Board of Trustees.	Revisions under Project 2020-05
4	November 17,2022	FERC Order RD22-5-000 issued approving FAC-002-4	
4	December 2, 2022	Effective Date	1/1/2024

A. Introduction

Title: System Operating Limits Methodology for the Operations Horizon

Number: FAC-011-4

Purpose: To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.

Applicability:

1.1. Functional Entities:

4.1.1. Reliability Coordinator

Effective Date: See Implementation Plan for Project 2015-09.

B. Requirements and Measures

R1. Each Reliability Coordinator shall have a documented methodology for establishing SOLs (i.e., SOL methodology) within its Reliability Coordinator Area. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M1. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL methodology.

R2. Each Reliability Coordinator shall include in its SOL methodology the method for Transmission Operators to determine which owner-provided Facility Ratings are to be used in operations such that the Transmission Operator and its Reliability Coordinator use common Facility Ratings *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL methodology, that addresses the items listed in Requirement R2.

R3. Each Reliability Coordinator shall include in its SOL methodology the method for Transmission Operators to determine the System Voltage Limits to be used in operations. The method shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

3.1. Require that each BES bus/station have an associated System Voltage Limits, unless its SOL methodology specifically allows the exclusion of BES buses/stations from the requirement to have an associated System Voltage Limit;

3.2. Require that System Voltage Limits respect voltage-based Facility Ratings;

3.3. Require that System Voltage Limits are greater than or equal to in-service BES relay settings for undervoltage load shedding systems and Undervoltage Load Shedding Programs;

3.4. Identify the minimum allowable System Voltage Limit;

3.5. Define the method for determining common System Voltage Limits between the Reliability Coordinator and its Transmission Operators, between adjacent Transmission Operators, and between adjacent Reliability Coordinators within an Interconnection.

M3. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL methodology that addresses the items listed in Requirement R3.

R4. Each Reliability Coordinator shall include in its SOL methodology the method for determining the stability limits to be used in operations. The method shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

4.1. Specify stability performance criteria, including any margins applied. The criteria shall, at a minimum, include the following:

4.1.1. steady-state voltage stability;

4.1.2. transient voltage response;

4.1.3. angular stability; and

4.1.4. System damping.

4.2. Require that stability limits are established to meet the criteria specified in Part 4.1 for the Contingencies identified in Requirement R5 applicable to the establishment of stability limits that are expected to produce more severe System impacts on its portion of the BES.

4.3. Describe how the Reliability Coordinator establishes stability limits when there is an impact to more than one Transmission Operator in its Reliability Coordinator Area or other Reliability Coordinator Areas.

4.4. Describe how stability limits are determined, considering levels of transfers, Load and generation dispatch, and System conditions including any changes to System topology such as Facility outages.

4.5. Describe the level of detail that is required for the study model(s), including the portion modeled of the Reliability Coordinator Area, and the critical modeling details from other Reliability Coordinator Areas, necessary to determine different types of stability limits.

4.6. Describe the allowed uses of Remedial Action Schemes and other automatic post-Contingency mitigation actions in establishing stability limits used in operations.

4.7. State that the use of underfrequency load shedding (UFLS) programs and Undervoltage Load Shedding (UVLS) Programs are not allowed in the establishment of stability limits.

M4. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL methodology that addresses the items listed in Requirement R4.

R5. Each Reliability Coordinator shall identify in its SOL methodology the set of Contingency events for use in determining stability limits and the set of Contingency events for use in performing Operational Planning Analysis (OPAs) and Real-time Assessments (RTAs). The SOL methodology for each set shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

5.1. Specify the following single Contingency events

5.1.1. Loss of any of the following either by single phase to ground or three phase Fault (whichever is more severe) with Normal Clearing, or without a Fault:

- generator;
- transmission circuit;
- transformer;
- shunt device; or
- single pole block in a monopolar or bipolar high voltage direct current system.

5.2. Specify additional single or multiple Contingency events or types of Contingency events, if any.

5.3. Describe the method(s) for identifying which, if any, of the Contingency events provided by the Planning Coordinator or Transmission Planner in accordance with FAC-014-3, Requirement R7, to use in determining stability limits.

M5. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL methodology that addresses the items listed in Requirement R5.

R6. Each Reliability Coordinator shall include the following performance framework in its SOL methodology to determine SOL exceedances when performing Real-time monitoring, Real-time Assessments, and Operational Planning Analyses: *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

6.1. System performance for no Contingencies demonstrates the following:

6.1.1. Steady state flow through Facilities are within Normal Ratings; however, Emergency Ratings may be used when System adjustments to return the

flow within its Normal Rating could be executed and completed within the specified time duration of those Emergency Ratings.

6.1.2. Steady state voltages are within normal System Voltage Limits; however, emergency System Voltage Limits may be used when System adjustments to return the voltage within its normal System Voltage Limits could be executed and completed within the specified time duration of those emergency System Voltage Limits.

6.1.3. Predetermined stability limits are not exceeded.

6.1.4. Instability, Cascading or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur.[1]

6.2. System performance for the single Contingencies listed in Part 5.1 demonstrates the following:

6.2.1. Steady state post-Contingency flow through Facilities within applicable Emergency Ratings. Steady state post-Contingency flow through a Facility must not be above the Facility's highest Emergency Rating.

6.2.2. Steady state post-Contingency voltages are within emergency System Voltage Limits.

6.2.3. The stability performance criteria defined in the Reliability Coordinator's SOL methodology are met[1].

6.2.4. Instability, Cascading or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur[1].

6.3. System performance for applicable Contingencies identified in Part 5.2 demonstrates that: instability, Cascading, or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur.

6.4. In determining the System's response to any Contingency identified in Requirement R5, planned manual load shedding is acceptable only after all other available System adjustments have been made.

M6. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL methodology that addresses the items listed in Requirement R6.

R7. Each Reliability Coordinator shall include in its SOL methodology a risk-based approach for determining how SOL exceedances identified as part of Real-time monitoring and Real-time Assessments must be communicated and if so, the timeframe that communication must occur. The approach shall include: *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

[1] Stability evaluations and assessments of instability, Cascading, and uncontrolled separation can be performed using real-time stability assessments, predetermined stability limits or other offline analysis techniques.

7.1. A requirement that the following SOL exceedances will always be communicated, within a timeframe identified by the Reliability Coordinator.

7.1.1 IROL exceedances;

7.1.2 SOL exceedances of stability limits;

7.1.3 Post Contingency SOL exceedances that are identified to have a validated risk of instability, Cascading, and uncontrolled separation;

7.1.4 Pre-Contingency SOL exceedances of Facility Ratings; and

7.1.5 Pre-Contingency SOL exceedances of normal minimum System Voltage Limits.

7.2. A requirement that the following SOL exceedances must be communicated, if not resolved within 30 minutes, within a timeframe identified by the Reliability Coordinator.

7.2.1 Post-Contingency SOL exceedances of Facility Ratings and emergency System Voltage Limits, and

7.2.2 Pre-Contingency SOL exceedances of normal maximum System Voltage Limits.

M7. Acceptable evidence may include, but is not limited to dated electronic or hard copy documentation of its SOL methodology that addresses the items listed in Requirement R7.

R8. Each Reliability Coordinator shall include in its SOL methodology: *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

8.1. A description of how to identify the subset of SOLs that qualify as Interconnection Reliability Operating Limits (IROLs).

8.2. Criteria for determining when exceeding a SOL qualifies as exceeding an IROL and criteria for developing any associated IROL T_V.

M8. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL methodology that addresses the items listed in Requirement R8.

R9. Each Reliability Coordinator shall provide its SOL methodology to: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

9.1. Each Reliability Coordinator that requests and indicates it has a reliability-related need within 30 days of a request.

9.2. Each of the following entities prior to the effective date of the SOL methodology:

9.2.1. Each adjacent Reliability Coordinator within the same; Interconnection;

9.2.2. Each Planning Coordinator and Transmission Planner that is responsible for planning any portion of the Reliability Coordinator Area;

9.2.3. Each Transmission Operator within its Reliability Coordinator Area; and

9.2.4. Each Reliability Coordinator that has requested to receive updates and indicated it had a reliability-related need.

M9. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation such as emails with receipts, registered mail receipts, or postings to a secure web site with accompanying notification(s).

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: "Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention: The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The Reliability Coordinator shall keep data or evidence of compliance with Requirements R1 through R9 for the current year plus the previous 12 calendar months.

1.3. Compliance Monitoring and Enforcement Program: As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

Requirement	Lower	Moderate	High	Severe
R1.	N/A	N/A	N/A	The Reliability Coordinator did not have a documented SOL methodology for establishing SOLs within its Reliability Coordinator Area.
R2.	N/A	N/A	The Reliability Coordinator included in its SOL methodology the method for Transmission Operators to determine which owner-provided Facility Ratings are to be used in operations, but the method did not address the use of common Facility Ratings between the Reliability Coordinator and the Transmission Operators in its Reliability Coordinator Area.	The Reliability Coordinator did not include in its SOL methodology the method for Transmission Operators to determine which owner-provided Facility Ratings are to be used in operations.
R3.	The Reliability Coordinator failed to incorporate one of the Parts of Requirement R3 into its SOL methodology.	The Reliability Coordinator failed to incorporate two of the Parts of Requirement R3 into its SOL methodology.	The Reliability Coordinator failed to incorporate three of the Parts of Requirement R3 into its SOL methodology.	The Reliability Coordinator failed to incorporate four or more of the Parts of Requirement R3 into its SOL methodology.
R4.	The Reliability Coordinator failed to incorporate one of	The Reliability Coordinator failed to incorporate two of	The Reliability Coordinator failed to incorporate three of	The Reliability Coordinator failed to incorporate four or

Requirement	Lower	Moderate	High	Severe
	the Parts of Requirement R4 into its SOL methodology.	the Parts of Requirement R4 into its SOL methodology.	the Parts of Requirement R4 into its SOL methodology.	more of the Parts of Requirement R4 into its SOL methodology.
R5.	N/A	N/A	The Reliability Coordinator failed to incorporate one of the Parts 5.2 or 5.3 of Requirement R5 into its SOL methodology.	The Reliability Coordinator failed to incorporate Part 5.1 of Requirement R5 into its SOL methodology. OR The Reliability Coordinator failed to incorporate Parts 5.2 and 5.3 of Requirement R5 into its SOL methodology.
R6.	The Reliability Coordinator failed to incorporate one of the Parts of Requirement R6 into its SOL methodology.	The Reliability Coordinator failed to incorporate two of the Parts of Requirement R6 into its SOL methodology.	The Reliability Coordinator failed to incorporate three of the Parts of Requirement R6 into its SOL methodology.	The Reliability Coordinator failed to incorporate four of the Parts of Requirement R6 into its SOL methodology.
R7.	N/A	The Reliability Coordinator included in its SOL methodology, a risk-based approach for determining how SOL exceedances identified as part of Real-time monitoring and Real-time Assessments must be communicated and if so, with what priority, but failed to	The Reliability Coordinator included in its SOL methodology, a risk-based approach for determining how SOL exceedances identified as part of Real-time monitoring and Real-time Assessments must be communicated and if so, with what priority, but failed to	The Reliability Coordinator failed to include in its SOL methodology, a risk-based approach for determining how SOL exceedances identified as part of Real-time monitoring and Real-time Assessments must be

Requirement	Lower	Moderate	High	Severe
		include one of the Parts 7.2.1 through 7.2.2.	include one of the Parts 7.1.1 through 7.1.5.	communicated and if so, with what priority.
R8.	N/A	N/A	The Reliability Coordinator failed to include Part 8.1 (a description of how to identify the subset of SOLs that qualify as IROLs) in its SOL methodology. OR The Reliability Coordinator failed to include Part 8.2 (a criteria for determining when violating a SOL qualifies as an IROL in its SOL methodology. OR The Reliability Coordinator failed to include Part 8.2 (criteria for developing any associated IROL T_v) in its SOL methodology.	The Reliability Coordinator failed to include Parts 8.1 and 8.2 in its SOL methodology.
R9.	The Reliability Coordinator failed to provide its new or revised SOL methodology to one of the parties specified in	The Reliability Coordinator failed to provide its new or revised SOL methodology to two of the parties specified	The Reliability Coordinator failed to provide its new or revised SOL methodology to three of the parties specified	The Reliability Coordinator failed to provide its new or revised SOL methodology to four or more of the parties specified in Requirement R9,

Requirement	Lower	Moderate	High	Severe
	Requirement R9, Part 9.2 prior to the effective date OR The Reliability Coordinator provided its new or revised SOL methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part 9.1 but was late by less than or equal to 10 calendar days.	in Requirement R9, Part 9.2 prior to the effective date OR The Reliability Coordinator provided its new or revised SOL methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part 9.1, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	in Requirement R9, Part 9.2 prior to the effective date OR The Reliability Coordinator provided its new or revised SOL methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part 9.1, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	Part 9.2 prior to the effective date OR The Reliability Coordinator failed to provide its new or revised SOL methodology to one or more of the parties specified in Requirement R9, Part 9.2 OR The Reliability Coordinator provided its new or revised SOL methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part 9.1, but was late by more than 30 calendar days. OR The Reliability Coordinator failed to provide its new or revised SOL methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part 9.1.

D. Regional Variances

None.

E. Associated Documents

Implementation Plan

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board	New
2		Changed the effective date to October 1, 2008 Changed "Cascading Outage" to "Cascading" Replaced Levels of Non-compliance with Violation Severity Levels Corrected footnote 1 to reference FAC-011 rather than FAC-010	Revised
2	June 24, 2008	Adopted by Board: FERC Order 705	Revised
2	January 22, 2010	Updated effective date and footer to April 29, 2009 based on the March 20, 2009 FERC Order	Update
2	February 7, 2013	R5 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.	
2	November 21, 2013	R5 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	
2	February 24, 2014	Updated VSLs based on June 24, 2013 approval.	
3	November 13, 2014	Adopted by the NERC Board	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS
3	November 19, 2015	FERC Order issued approving FAC-011-3. Docket No. RM15-13-000.	

4	May 13, 2021	Adopted by the NERC Board of Trustees	Revised under Project 2015-09
4	March 4, 2022	FERC Letter Order issued approving Docket No.RD22-2-000.	
4	March 4, 2022	Effective Date of Standard	April 1, 2024

No. A24-0845

STATE OF MINNESOTA

IN COURT OF APPEALS

In the Matter of the Formal Complaint and Request for Relief
by the Minnesota Solar Advocates

BRIEF OF RESPONDENT MINNESOTA PUBLIC UTILITIES COMMISSION

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The Commission has established standards for utilities to interconnect distributed generation to the distribution system.[10] *See* Minn. Stat. § 216B.1611, subd. 2(a) (requiring the Commission to establish generic standards for interconnection). Standards for interconnection and operation of distributed energy resources (called the State of Minnesota Distributed Energy Resource Interconnection Process – "MN DIP"; and the Minnesota Technical Interconnection and Interoperability Requirements ("TIIR")) are required to be consistent with industry operational and safety standards and provide for the low-cost, safe and standardized interconnection of facilities. Minn. Stat. § 216B.1611, subd. 2(a)(1).

The standards must also reflect the particular characteristics and needs of the utility. Specifically, the standards must take into account differing system requirements and hardware, and overall demand load requirements of individual utilities. *Id*. at subd. 2(a)(3). The standards must also reflect terms that allow a utility to be assured of the reliable, safe and efficient operation of the interconnected equipment. *Id.* at subd. 2(a)(4). The MN DIP and TIIR were approved after an extensive stakeholder process and record development.[11]

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[10] Order Approving Tariffs with Modifications and Requiring Compliance Filings, Docket 16-521, et al. (Minn. Pub. Utils. Com'n. Apr.19, 2019), https://mn.gov/puc/assets/April%2019%2C%202019%20Order_tcm14-431305.pdf
Order Establishing Updated Technical Interconnection and Interoperability Requirements, Docket 16-521 (Minn. Pub. Utils. Com'n. Jan. 22, 2020), https://mn.gov/puc/assets/January%2022%202020%20Order_tcm14-431303.pdf

[11] Order Establishing Standards, Docket 01-1023 (Minn. Pub. Utils. Com'n. Sept. 28, 2004) https://www.edockets.state.mn.us/edockets/searchDocuments.do?method=showPoup&documentId={EB5DCE72-415A-4767-965F-35BA37EC59EA}&documentTitle=59785

In its initial comments, Xcel addressed each of the alleged statutory violations. *Id*. at R000162-65. Xcel explained that two of the referenced statutes (§§ 216B.164 and 216B.1641) relate to limiting cumulative generation capacity of net metered facilities and CSGs; and TPS does not limit cumulative generating capacity. Doc. 15; R000162-63. Minnesota Statutes Section 216B.1611 relates to Commission adoption of standards (as described at p. 7 *supra*), not utility practice; and not every utility practice constitutes a "rate" that must be approved by the Commission under Minnesota Statutes Section 216B.16. Doc. 15; R000162-64. Finally, Xcel countered that the TPS does not create discriminatory or unreasonable rates, or unreasonably prejudice or disadvantage customers (addressing Minn. Stat. §§ 216B.03, .05 and .07) because it is based on Xcel's judgment as to what is required for safety and reliability. Doc. 15; R000163-65. Xcel further claimed the Complaint failed to show how the TPS was discriminatory. *Id.* at R000165.

Regarding the complaints from residential customers seeking to interconnect to Xcel's distribution system, the Company explained:

> Today, CSGs are clustered on a limited number of Company feeders, saturating them to capacity limits. This drives up the cost, technical complexity, and time to interconnect additional CSGs and other DER to those feeders. This can also leave a small customer-sited solar project (less than 40 kW AC) with a frustrating wait for an answer on its application for interconnection and/or also be faced with very large costs to interconnect.

Doc. 15; R000145.

Xcel noted that new legislation is addressing the ability of these smaller customers to interconnect, including:

in the TPS by dismissing the complaint "at this time," and without prejudice, the decision is not arbitrary or capricious.

The Court in *MPIRG* also rejected a claim that a Commission refusal to hold a hearing on a complaint was arbitrary or capricious. The Court held that because the Commission considered the complainant's claims and had a reasoned and sound basis for its decision, the court would not substitute its judgment for that of the agency. 360 N.W.2d at 657. In this case Commissioners questioned Xcel's engineers and other parties at length. Doc. 54. The Order and transcript reflect the Commission's understanding that the TPS was based on the utility's concern for reliability of service and its ability to meet statutory directives to service additional DER, but that further discussion and possible action by the Commission may be appropriate. Doc. 42; R000477-78. In that context, an alleged absence of specific evidentiary support for safety and reliability arguments in support of the TPS, or a conflict in testimony does not compel an investigation. Relator thus fails to meet the clear and convincing standard to establish arbitrary and capricious action. *See City of Moorhead*, 343 N.W.2d at 849; *Petition of Minnesota Power*, 394 N.W.2d at 234 (where the evidence did not compel a different result, the clear and convincing threshold is not met.)

With respect to addressing the claimed statutory violations, the question before the Commission and decided in the order was *not* whether Xcel had violated any statute, it was whether there were reasonable grounds to investigate the allegations in the complaint. Relator agrees on this point. Relator's Br., p. 31 ("MnSEIA was not asking the Commission to determine whether the [TPS] was consistent with Minnesota law or in the

public interest."). The primary allegation in the complaint was whether the cited statutes required Commission approval prior to implementing the TPS. *See* Doc 1; R000002. As discussed *supra* at pp. 21-23, there is no statute requiring Commission approval of the TPS.

That the Commission's Order does not address each statute Relator claims that the TPS violates is by no means per se error. *See, e.g.*, *In re Appl. for PERA Retirement Benefits of McGuire*, 756 N.W.2d 517, 520-21 (Minn. App. 2008) (not arbitrary or capricious for the agency to fail to address equitable estoppel claim); *In re Appl. from Minn. Orchestral Ass'n for a Variance*, 607 N.W.2d 478, 482 (Minn. App. 2000) (MPCA did not err in failing to consider a local ordinance). Under the arbitrary or capricious standard, the Court must uphold a decision if the agency's path is reasonably discernible. *Space Ctr. Transp.*, 444 N.W.2d at 581. The Commission's path is reasonably discernible because the issue before the Commission was not whether the TPS violates a statute but only whether to investigate, and the complaint reflected a misreading of the statutes cited.

Specifically, Relator's arguments based on two statutes (Minn. Stat. §§ 216B.164, subd. 4b, and .1641, subd. 1) suggest there can be absolutely no practical limits on interconnection of DER. This Court held in *In re Northern States Power Co.*, 2016 WL 3043122 at *3 (Minn. App. May 31, 2016), that the "no limitation" language in Minn. Stat. § 216B.1641(a) refers to a limit on the CSG program as a whole. The TPS does not operate as a limit on the generation of CSGs as a whole. Moreover, each of these statutes addresses the *cumulative generation* of certain types of DER. Minn. Stat. §§ 216B.164, subd. 4b; 216B.1641, subd. 1. The TPS operates as a limit on the distribution system capacity used in interconnection review for a proposed project at a particular feeder, and this capacity

often operates as a practical limit on generation on that feeder.[22] As to the claim that the TPS violates Minn. Stat. § 216B.1611, that statute requires the Commission to establish standards for interconnection, which it has done through the MN DIP and TIIR. *See* fn. 10 *supra*. Xcel is not the Commission, and this statute places no obligation on Xcel.

Finally, Relator again argues that the TPS as a utility practice constitutes a rate and thus violates various statutes (Minn. Stat. §§ 216B.03, 216B.05, 216B.07, 216B.16) associated with utility ratemaking. Because under the statutory definition only practices "affecting [utility] compensation, charge, fare, toll, rental, tariff, or classification" constitute "rates", and any inclusion in tariff would be premature at this point, the argument fails. *See* pp. 22-23 *supra*.

The Commission concluded the TPS was about the practical limits of Xcel's system and did not implicate statutory compliance. Doc. 42; R000476. This conclusion explains why the Commission did not address each of the alleged statutory violations. That conclusion, bolstered by a record including Xcel's response to the allegations of statutory violations, gives the Court a sufficient basis on which to "reasonably discern" the Commission's rationale for dismissal of the complaint. *Space Ctr. Transp.*, 444 N.W.2d at 581; *see also Alternative Operator Servs.*, 490 N.W.2d at 924 (entire record

[22] For example, as shown in the diagram at p. 8 *supra*, under certain circumstances a solar developer must pay for upgrades to the distribution system. That payment requirement functions as a very real limit on generation – a practical one, but one that is not directed at generation; it is simply a practical necessity for the utility to operate its distribution system in a cost-effective manner.

Court should defer to the Commission's judgment on whether an investigation at this time is in the public interest.

CONCLUSION

This Court should reject Relator's attempt to conflate routine certiorari review of a regulatory decision into a referendum on the agency's performance. Because Relator has not satisfied its burden to show, by clear and convincing evidence or any lesser standard, that the Commission abused its considerable discretion in dismissing the complaint, the Commission's decision should be affirmed.

Dated: September 25, 2024

Respectfully submitted,

KEITH ELLISON
Attorney General
State of Minnesota

s/ Susan C. Gretz

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Assistant Attorney General
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JEFFREY K. BOMAN
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ATTORNEYS FOR RESPONDENT

414 Nicollet Mall
Minneapolis, MN 55401

August 15, 2022

—Via Electronic Filing—

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

RE: STAKEHOLDER MINUTES
COMMUNITY SOLAR GARDENS
DOCKET NO. E002/M-13-867

Dear Mr. Seuffert:

Northern States Power Company, doing business as Xcel Energy, submits the attached Compliance information in response to the Commission's February 13, 2015 Order (Order Point 3) submitted in the above-noted docket. Per Commission Order, all agendas, approved minutes and attachments from the Solar*Rewards Community (S*RC) Implementation Workgroup will be filed in eDockets. We note that we have expanded our working group efforts to begin to include all Distributed Energy Resources (DER). Therefore, we include the meeting minutes from the MN DER Implementation Workging group here. Attachment A includes the meeting minutes for our May 19, 2022 workgroup.

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 me at jessica.k.peterson@xcelenergy.com or 612-330-6850 if you have any questions regarding this filing.

Sincerely,
/s/

JESSICA PETERSON
MANAGER, PROGRAM STRATEGY AND PERFORMANCE

Enclosure
c: Service List

MN DER Implementation Workgroup

2022 Quarter Two – May 19, 2022
Meeting Minutes
Approved by Workgroup on August 11, 2022.

PRESENT INCLUDE:

Full Name	Organization
Dana Miller	Amp
Mat Orner	Apadana
Charlie Stenstrom	Cedar Creek Energy
Bruce Konewko	CEF
Dan	CEF
Roxanne Vinciquarra	CleanChoice Energy
Pouya Najmaie	Cooperative Energy
Neta Eitan	Development Services, Inc.
Russel Gilberg	Energy Concepts LLC
Roxanne Baker	Ethical
Natalie Townsend	Fresh Energy
J. Drake Hamilton	Fresh Energy
Dan	Guest
Amanda Werner	Guest
Gordy	Guest
Nicole	Guest
Shiva Gowrinathan	Hansen Technologies
Wendy Vorasane	Ideal Energies, LLC
Megan Gallagher	Impact Power Solutions
Ian Santos-Meeker	Impact Power Solutions
Jeffrey Barber	Knobelsdorff Enterprises, Inc.
Travis Murray	MN AGO
Kristin Berkland	MN AGO
John Dybvig	MN PUC
Nick Nigro	MnSEIA
Doug Shoemaker	MRES
Andrey Tolkachev	Nautilus Solar Energy
Chengjun Liang	Nexamp
Matt Walsh	Nexamp
Devin Beltran	Nexamp

Adam Siegelstein	NextEra Energy Resources
Matthew Melewski	Nokomis Energy
Zeeshan Yasin	Novel Energy Solutions
David Shaffer	Novel Energy Solutions
Colin O'Neil	ReneSola Power
Eric Jensen	ReneSola Power
Gordon Simanton	SolarStone Partners
Jordan Eggert	Spark Power Corp
Steve Coleman	Sundial Energy
Joel Cipcic	Sunrise Energy Ventures
Michael Cathcart	Sunrise Energy Ventures
Christy Leopold	TBR
Donna Pickard	TruNorth Solar
Lisa Nielsen	TruNorth Solar
Ross Abbey	US Solar
Nicole Vaughn	Vaughn CO
Will Kenworthy	Vote Solar
Anthony Maiolo	Xcel Energy
James Denniston	Xcel Energy
Karl Johnson	Xcel Energy
Mike Sans Crainte	Xcel Energy
Carissa Cavalieri	Xcel Energy
Kylie Kiecker	Xcel Energy
Jeffrey Buttermore	Xcel Energy
Rehana Power	Xcel Energy
Matthew Hagen	Xcel Energy
David Madigan	Xcel Energy
Jacob Hillman	Xcel Energy
Kiwa Anisman	Xcel Energy
Nicholas Coquyt	Xcel Energy
Dean Schiro	Xcel Energy
Tim J Rossbach	Xcel Energy
Michael Ruiz	Xcel Energy
Violeta Vidakovic	Xcel Energy
Callie Walsh	Xcel Energy
Jessica Peterson	Xcel Energy
Lee E Gabler	Xcel Energy
Michael Boerboon	Xcel Energy
Kerry Klemm	Xcel Energy
Kelsey Loomis	Xcel Energy
Michael Palmer	Xcel Energy

(TRANSMISSION SYSTEM IMPACT STUDIES)

Transmission System Impact Studies, as noted from the Public Utilities Commission order, the agreement that Xcel Energy had in place between Xcel Energy and MISO has been stayed.

Right now, what would be available when it is determined that there's an impact to the transmission system would be to utilize the MISO ad hoc process. Xcel Energy is evaluating its options there to determine how that can be effectively utilized in the meantime.

The MISO interconnection process working group (IPWG) is currently also working on a MISO wide agreement for studying the distributed energy resources that are across the MISO system. They have already had a couple of meetings of the working group. There are several more meetings throughout the remainder of 2022. Upcoming meetings will be held on June 6, 2022, then August 15,2022, October 10, 2022, and November 14, 2022.

As noted, MISO is looking at the screening criteria and the analysis to determine and study impacts of the distribution connected resources that have an impact on the transmission system and then the intent would be working on a MISO wide study agreement.

(COST SHARING)

A quick reminder of the Cost Sharing order point. Back at the end of March, the Commission approved the Cost Sharing program for Xcel Energy, which applies for customers with DER systems 40 kW AC or less. The original proposal was put together by Fresh Energy, IREC and TRUNorth. The plan is for Xcel Energy to implement this program by the end of August of this year, within 60 days of the order and capping the individual upgrades that customers can take advantage of at $15,000 per project.

Once the program and the tariffs are approved and launched, that would mean all projects 40kW AC or less that submit their application on or after the launch date and submitted the cost sharing fee will be eligible to be covered for future upgrade costs up to $15,000. This will be an additional fee to the application.

As noted in the proposal, this Cost Sharing fee will cover both the Supplemental Review fees for all projects that may require Supplemental Review and any upgrade costs up to the previously established $15,000 cap. However, it excludes any study fees, Phase II study fees or metering costs. Eligible projects would receive available upgrade funding on a first come, first served basis. Once a project gets to the point where they go through the Facilities Study and received the Facility Study results, Xcel Energy is going to check the fund to see how much is available and allocate the appropriate amount to that project.

Xcel Energy intends to follow the same MNDIP timelines and will not instigate or start a waitlist for these funds. If there are not any funds available, the customer would be responsible for payment to keep their application moving forward and would need to pay up and above what is available within the funds.

Xcel Energy intends to review the program structure on a periodic basis, as necessary.

Improving Transparency

2021

1. Engineering Practice: Overhead Conductor
2. Engineering Practice: Voltage Regulators
3. Engineering Practice: Maximum Conductor Size for DER
4. Engineering Practice: Technical Planning Limits
5. Diagram: Technical Planning Limits
6. Office Hour: DER Technical Planning Limits PowerPoint (September 24, 2021)
7. Office Hour: DER Technical Planning Limits Recording (September 24, 2021)
8. Follow-up Questions and Answers: DER Technical Planning Limits
9. Suggested Tools to Use Before Submitting an Interconnection Application

2022 Q1

1. Affected System Impact Study Agreement (Xcel Energy and MISO)
2. Transmission System Impact Study Agreement (Xcel Energy and Interconnection Customer)
3. Office Hour: MISO Transmission Affected System Impact Study PowerPoint
4. Office Hour: MISO Transmission Affected System Impact Study Recording
5. Office Hour MISO Transmission Affected System Impact Study Follow-up Q&A
6. Xcel Energy Standard for Electric Installation and Use
7. Updated Example One Lines, Site Plan, Labeling

DGWG

4. Transmission System Impact Study

- Commission Order Stayed Agreement between XE and MISO
- Ad Hoc Process is currently available for review of transmission impact
- MISO Interconnection Process Working Group (IPWG)
  - 2022 Meetings: June 6, August 15, October 10, and November 14
  - Key points:
    - MISO wide screening criteria and analysis
    - MISO wide study agreement
- **Questions?**

Xcel Energy®

414 Nicollet Mall
Minneapolis, MN 55401

January 31, 2023

—Via Electronic Filing—

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

RE: QUARTERLY COMPLIANCE FILING
COMMUNITY SOLAR GARDENS
DOCKET NO. E002/M-13-867

Dear Mr. Seuffert:

Northern States Power Company, doing business as Xcel Energy, submits this Quarterly Compliance Report to the Minnesota Public Utilities Commission. This Report provides the status of the Solar*Rewards Community program as of January 1, 2023.

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 Kristen.S.Ruud@xcelenergy.com or 612-216-7979 if you have any questions regarding this filing.

Sincerely,

/s/

JESSICA PETERSON
MANAGER, PERFORMANCE AND STATEGY
DSM AND RENEWABLE PROGRAMS

Enclosures
c: Service List

Table 4: Quarterly Study Results – Facilities Study (FS) (Q4 2022)

	October	November	December
Number of Facilities Studies Due (per month)	**6**	**12**	**9**
FS Delivered by Original Due Date	0	4	1
FS Delivered by Adjusted Due Date	4	0	5
FS Delivered but not by either Due Date	**0**	**2**	**0**
Total Studies Delivered	**4**	**6**	**6**
Studies due and not yet delivered (categorized by reason)	***2***	***6***	***3***
Batch/Cluster Study	*0*	*4*	*0*
Operational Delays	*2*	*2*	*3*

For the projects noted as delivered "not yet delivered", we provide the following additional detail:

- *Batch/Cluster Study:* Those projects voluntarily moving through a batch or cluster study often have extended timelines as there are several projects together being completed with increased complexity and time required. These projects are included in our Group Study Compliance.
- *Modeling Issues*: Some models involve a large variety of equipment, load characteristics, and generation which require extensive data validation, and troubleshooting analyses to ensure the model yields results which accurately represent the distribution system.
- *Operational Delays*: Some projects have had operational delays because of modeling verification through quality assurance, a delay in timing between days, or an error by the program team.
- *MISO Study* – The Company has sent its first project to MISO for review. Results are pending.

B. Engineering Review Process

There are currently 293 CSG applications in progress under the MN DIP process that have been Deemed Complete and are now moving through engineering review.

414 Nicollet Mall
Minneapolis, MN 55401

February 21, 2023

—Via Electronic Filing—

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

RE: STAKEHOLDER MINUTES
COMMUNITY SOLAR GARDENS
DOCKET NO. E002/M-13-867

Dear Mr. Seuffert:

Northern States Power Company, doing business as Xcel Energy, submits the attached Compliance information in response to the Commission's February 13, 2015 Order (Order Point 3) submitted in the above-noted docket. Per Commission Order, all agendas, approved minutes and attachments from the Solar*Rewards Community (S*RC) Implementation Workgroup will be filed in eDockets. We note that we have expanded our working group efforts to begin to include all Distributed Energy Resources (DER). Therefore, we include the meeting minutes from the MN DER Implementation Workging group here. Attachment A includes the approved meeting minutes for our November 17, 2022 workgroup along with the powerpoint pertaining to that meeting.

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 Kristen Ruud at Kristen.S.Ruud@xcelenergy.com if you have any questions regarding this filing.

Sincerely,
/s/

JESSICA PETERSON
MANAGER, PROGRAM STRATEGY AND PERFORMANCE

Enclosure
c: Service List

MN DER Implementation Workgroup

2022 Quarter Four – November 17, 2022

Meeting Minutes

PRESENT INCLUDE:

Full Name	Organization
Danielle DeMarre	All Energy Solar
Dena Webster	All Energy Solar
Mat Orner	Apadana
Rozanne Vinciquarra	Clean Choice Energy
Sarah Kittross	Clean Choice Energy
Nubia Baptiste	Clean Choice Energy
Bruce Konewko	Cooperative Energy Futures
Laura Brown	Development Services, Inc.
Natalie Haberman	Fresh Energy
Courtney O'Conno	Gordian Energy System
Jordan Betts	Green Lantern Solar
Shiva Gowrinathan	Hansen Technologies
Wendy Vorasane	Ideal Energies, LLC
Aaron Kueffer	Minnesota Power
Bridget Clements	MN Solar
Andrey Tolkachev	Nautilus Solar Energy
Megan Gallagher	New Energy Equity
Amy Woldt	Nokomis Energy
Fritz Ebinger	Nokomis Energy
Jamie Giguni	Nokomis Energy
Dana Hallstorm	Nokomis Energy
David Shaffer	Novel Energy Solutions
Bob Olson	Olson Energy Corporation
Maggie Clymer	Pivot Energy
Myra Gardiner	PurEnergy LLC
Aidan Keegan	Solar Landscape
Mouli Vaidyanathan	SolarPod
Travis Tufte	SolarPod
Steve Coleman	Sundial Energy
Holland Parker	SunShare

A. GROUP STUDIES

Xcel Energy gave a brief update on the cluster study efforts. Xcel Energy hosted a stakeholder workshop series for cluster studies that concluded on June 30th. Following the conclusion of the series, Xcel Energy filed the report with the Commission on July 25th. The report included an issues matrix detailing the resolved and unresolved issues surrounding cluster study implementation at that time. Two clusters had been completed, with more than 10 in progress. There has been anticipation to implement mandatory clusters on feeders with capacity constraint or significant queued DERs on hold. A report was filed on September 30, 2022, and its main purpose was to update the Commission on how the effort was going, how many studies were completed, and what the outcomes were at that time. In September, Xcel Energy completed 5 cluster study projects. Since then, 4 of these projects have been withdrawn. At that time, 7 more projects were in progress, and of those 7 projects, 3 of them are now complete with the remaining 4 still in progress. Xcel Energy has submitted 6 additional agreements for Cluster Studies.

B. SMART INVERTERS

Xcel Energy spoke on efforts to move towards Smart Inverter implementation when they become readily available, to align with the MNDIP process. There was an initial Office Hour on July 27, 2022, laying out Xcel Energy's proposed plan. The recording and PowerPoint are now available on the Interconnection webpage. Subsequent to this, the DGWG was directed to form a technical subgroup to work on the Smart Inverter topic as well. This included required updates to the TIIR, which is applicable across the entire state of Minnesota.

- Office Hour: Smart Inverters PowerPoint (July 27, 2022) (PPTX)
- Office Hour: Smart Inverters Recording (July 27, 2022)

The projected timeline for the updates and implementation of Smart Inverters was proposed through a Commission Notice on September 15, 2022. Once Smart Inverters are deemed readily available, this timeline will go into action.

The DGWG technical subgroup has been meeting every second week to work through updates that will be needed for the TIIR. The TIIR will utilize the advanced functionalities of smart inverters, primarily the autonomous functions for reactive power support or Volt-VAR capability and active power control Volt-Watt. The subgroup is progressing and will be able to meet the timelines as established within the notice.

C. MISO TRANSMISSION

Xcel Energy explained that MISO, Midcontinent Content Independent System Operator, has been working through the Interconnection Process Working Group (IPWG). IPWG has been meeting on a regular basis, as one of their topics throughout the year is specifically focused on the MISO study for affected transmission system studies. Xcel Energy provided

everyone with the materials from the last meeting of the IPWG, on November 14, 2022, including the Whitepaper that summarizes the process for affected system studies.

The screening for the first quarterly cycle will be in the August 2023 timeframe. Once the projects are evaluated with screening, they would go into a study. Those studies would be completed later in 2023 and the results complied in the first quarter of 2024, following the MISO study timeline.

Comment: IPWG meetings are addressing the transmission affected system impact studies and use the acronym TASIS. This will be important for developers and other interconnection customers to understand.

Response: Couldn't agree more.

E. TOOLS TO USE

Xcel Energy spoke about resources available before applications are submitted in order to gain initial indication of the feeders' potential available capacity for interconnection. All resources are available on Xcel Energy's interconnection website. One of these resources is the Hosting Capacity Map. More information can be found by clicking on the presentation to a workshop series on this item as well.

Another resource is the monthly Public DER Queue Report, which includes a tab that identifies Known Capacity Constraints that will include both feeders and substations that are currently constrained. That will help to identify any applications on those feeders that are probably going to take a longer time to process and will most likely need further in-depth studies. Information on the Public Queue Report is updated on a monthly basis.

Another tool is the Pre-application Data Report for a $300.00 fee. This report provides information about the feeder and the substation serving a particular area that can be used to give guidance on submitting an interconnection application. . However, the Pre-application Data Report is informational only and does not guarantee anything to the applicant.

Once again, all of these resources are available on Xcel Energy's webpage, but stakeholders can reach out to the program for questions on those as well.

- Interconnection | Renewable Developer Resources | Xcel Energy
- Suggested Tools to Use Before Submitting an Interconnection Application

Question: I have a question about the public queue report and the known capacity constraints tab. There are feeders with aggregate DER greater than daytime minimum load and feeders that we have typically found to only be in that constraint, so it doesn't meet any of the other constraints listed on this tab. We haven't historically seen feeders with applications on hold. If that is the only known issue, I see that a couple of feeders with applications of less than 40 kilowatts are getting placed on hold when that's the only known capacity constraint. Is this a change in the review of the capacity constraints or placing

MISO Transmission Affected Systems Study

The last Midcontinent Independent System Operator (MISO) IPWG meeting was **November 14, 2022**. Meeting details are available here.

- DRAFT MISO Whitepaper

Who? The outcomes of the MISO IPWG will impact Disturbed Energy Resources (DER) in Minnesota, including Solar*Rewards Community interconnection applications – *you!*

Why? "To provide stakeholders a forum to develop revised generator interconnection queue process procedures with the goal of reducing study time and increasing certainty. It is intended that the work product of this Working Group will be included in Tariff filings to FERC and modifications to the Generator Interconnection Business Manual." - misoenergy.org

Questions or interested in future meetings? Additional information is available on the MISO Interconnection Process Working Group (misoenergy.org) webpage.

414 Nicollet Mall
Minneapolis, MN 55401

PUBLIC DOCUMENT
NOT PUBLIC DATA EXCISED

August 15, 2023

—Via Electronic Filing—

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

RE: COMPLIANCE FILING – QUARTERLY 2023 REPORT
GENERIC STANDARDS FOR INTERCONNECTION AND OPERATION OF
DISTRIBUTED GENERATION FACILITIES
DOCKET NOS. E999/CI-16-521 & E,G-002/M-12-383 & E002/M-18-714

Dear Mr. Seuffert:

Northern States Power Company, doing business as Xcel Energy, submits this Quarterly Compliance Report as required by the Minnesota Public Utilities Commission's February 18, 2021 Order Accepting Filing and Denying Request to Exclude Complaints at Order Point 4 and the Notice of Quarterly Reporting Requirements issued on May 12, 2021.

Certain information in Attachment A is nonpublic and is Protected Information that is not in the public version of this filing. For example, pursuant to Minn. Stat. §13.02, subd 9, the pre-incentive installed costs and zip code information is generally nonpublic, consistent with the requirements in Minn. Stat. §216B.1611, subd. 3a(d). Other information may also be nonpublic because in combination with other publicly available information, it could identify specific customers.

Also, consistent with the need to protect "security information" under Minn. Stat. §13.37, subd 1(a), the Company generally does not publicly provide certain combinations of information about its grid including city information and feeder/substation information. This approach has been developed over time and includes the Commission discussion of what type of data to publicly provide in our Service Quality Performance reports, as reflected in our March 30, 2018 filing of our 2017 Annual Report in Docket No. E002/M-18-239 at page 13. This resulted in the Company publicly providing the city, but not also publicly providing the feeder/substation. This approach aligns with the Company's prior practice in this

filing, the Company committed to reporting ongoing progress of the Group Study pilot in future MN DIP Quarterly Compliance filings.

From September 2022 through June 30, 2023, a total of 121 applications are currently in or have completed cluster study. Approximately 15 percent of these applications are in FS, 33 percent are in SIS, 25 percent are on-hold while the previous in-queue project study is complete, and the remaining 27 percent have withdrawn their application.

VI. EQUIPMENT LEAD TIMES

The industry has experienced significant supply chain lead times which have persisted over the past few years. The Company is now seeing a substantial increase in equipment lead times for primary metering equipment. Historically, larger DER projects and Solar*Rewards Community applications were required to have metering equipment ordered no later than 32 weeks prior to the in-service date (ISD). As a result of the increase in lead times, in July 2023 we updated the timeline for procurement to require primary metering equipment be ordered no later than 50 weeks prior to the ISD. Secondary metering equipment lead times will remain unchanged. Also, transformer availability continues to be an issue. Even though the Company is installing oversized transformers when available, sourcing from new manufacturers, expanding our inventory & contracts, and expanding our internal/external transformer rebuild program, we have seen these lead times pushing past 52 weeks. We expect these lead time issues to continue through 2024 and impact additional equipment, like primary cable.

VII. TRANSMISSIONS STUDIES

Starting in October 2022, Xcel Energy implemented the MISO transmission study process for a MISO review and study of DER interconnection applications that have potential to adversely impact the transmission system under the MISO criteria that triggers a MISO review. In Q2, the Company has received its first completed report since the start of this process. Additional reports are currently under review and the Company expects to provide more details on this process in future MN DIP Quarterly reports.

VIII. SMART INVERTER IMPLEMENTATION

On March 2, 2023, the Distributed Generation Work Group (DGWG) presented updates to the State of Minnesota Technical Interconnection and Interoperability Requirements (TIIR) for Commission approval, including changes required to move for full implementation of the TIIR to use IEEE 1547-2018 certified inverters. The Commission

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

Xcel Energy		Information Request No.	1
Docket No.:	E999/CI-16-521		
Response To:	Minnesota Public Utilities Commission		
Requestor:	Sophie Nikitas		
Date Received:	October 27, 2023		

Question:
Does Xcel consider itself to be a Transmission Provider?
The MN DIP Glossary of Terms describes a Transmission Provider: "The entity (or its designated agent) that owns, leases, controls, or operates transmission facilities used for the transmission of electricity. The term Transmission Provider includes the Transmission Owner when the Transmission Owner is separate from the Transmission Provider. The Transmission Provider may include the Independent System Operator or Regional Transmission Operator."

Response:
Yes. Northern States Power Company owns the transmission facilities and therefore qualifies under the above definition as being a Transmission Provider. MISO is also a Transmission Provider under the above definition because it controls the transmission facilities.

Preparer:	Jason Standing
Title:	Manager, Transmission Planning
Department:	Transmission Planning
Telephone:	612-330-7768
Date:	November 14, 2023

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

Xcel Energy		Information Request No.	2
Docket No.:	E999/CI-16-521		
Response To:	Minnesota Public Utilities Commission		
Requestor:	Sophie Nikitas		
Date Received:	October 27, 2023		

Question:

Nokomis Energy's October 4, 2023 Letter includes Xcel's 2023 Q3 MN DER STAKEHOLDER WORKGROUP (Aug. 9, 2023) slides 34-37 where Xcel presents a new study process "Xcel Energy Transmission Affected System Impact Study Process" (Xcel Transmission Affected System Study). Xcel cites MN DIP 4.3.6-4.3.8 as the basis for this new process. Please describe:

a) Why MISO's Transmission Study Process is not sufficient "to protect Transmission reliability" and the Xcel Transmission Affected System Study is needed as claimed on Slide 37;
b) MN DIP 4.3.6 states when a transmission affected study is warranted: "In instances where the System Impact Study shows potential for Transmission System adverse system impact". Please explain how Xcel Transmission Affected System Study complies with MN DIP 4.3.6 in more detail.
c) MN DIP 4.3.8 requires "A Transmission System impact study, if required, shall be completed and the results transmitted to the Interconnection Customer in as timely a manner as possible after the transmission system impact study agreement is signed by the Parties." Please explain how the quarterly process proposed complies with MN DIP 4.3.8 in more detail.

Response:

a) From a safety and reliability perspective, we need transmission system impact studies when there is reverse flow onto the transmission network. Under the MISO trigger, there is a worrisome gap in performing necessary studies. MISO's System Impact Study is only triggered when DER would exceed peak loading scenarios. But there is a significant amount of time the feeders/distribution substation are not at system peak and DER production during these times could have a material impact on the safety and reliability of the system. For example, at daytime minimum load (DML) times, solar may be at full output. Accordingly, when DER exceeds DML but is less than peak substation load, we need to assess under an Xcel Energy Transmission System Impact Study the potential impact of DER on the safety and reliability of transmission system under this scenario. The Xcel Energy Transmission

System Impact Study applies to the gap between the DML and peak load scenarios, and this gap needs to be studied from a safety and reliability perspective.

b) The MNDIP process allows for additional transmission studies if deemed necessary. Whether it is for a MISO Transmission Study or an Xcel Energy Transmission Study, projects are screened to determine whether reverse flow is identified in each substation. Specifically, a MISO Transmission study is triggered when the reverse flow is identified to exceed peak substation load. An Xcel Energy Transmission study is triggered when reverse flow exceeds the substation DML. In either case, reverse flow to the substation would show potential for Transmission System adverse impact for both safety and reliability and therefore creates a need for the studies in both scenarios. Therefore, both the MISO and Xcel Energy Transmission Studies both comply with MN DIP 4.3.6.

c) A quarterly System Impact study is a reasonable cadence for all affected DER requests involving transmission system impact studies. A quarterly cadence is typical of several other study processes that occur through MISO, including the process for MISO Transmission System Impact Studies for DER interconnections.

MN DIP 4.3.8 does not provide a specific timeframe for completing Transmission Studies, which allows for flexibility in determining in the best timeframe possible to complete the studies and provide the results to the Interconnection Customer in a timely manner. In addition, the quarterly timeframe for the MISO Transmission Study is determined by MISO and their process, which is not under Xcel Energy's control. Note, however, that the transmission system is much larger than the distribution system and requires a larger scope than the typical distribution system impact study. Therefore, to ensure that the interconnection customer receives the results in a timely manner and to stay consistent with MISO's process for performing their Transmission Studies, the quarterly timeframe was the selected timeframe due to the scope of the study.

Preparer:	Jason Standing
Title:	Manager, Transmission Planning
Department:	Transmission Planning
Telephone:	612-330-7768
Date:	November 14, 2023

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Xcel Energy		Information Request No.	3
Docket No.:	E999/CI-16-521		
Response To:	Minnesota Public Utilities Commission		
Requestor:	Sophie Nikitas		
Date Received:	October 27, 2023		

Question:
Does Xcel use the 2022 TASIS Agreement that preceded MISO's DER Affected System Studies found in MISO's Business Practice Manual – 015 Generation Interconnection (see BPM-015 r26))? If so, explain why and how this complies with the Commission's March 31, 2022 Order?

Response:

No. The Company understands the term "2022 TASIS Agreement" to refer to that agreement attached to the December 17, 2021 letter filing of Xcel Energy in Docket No. E999/IC-16-521. Xcel Energy has not used that agreement. The Commissioner discussion at the January 20, 2022 Agenda Hearing on this issue clearly indicated that the MISO transmission studies would still be needed, and that the action of the Commission would not require placing projects on hold. (Hearing recording at about 2:42:50 and at about 3:53:10).

For the time that preceded MISO's DER Affected Studies found in MISO's Business Practice Manual – 015 Generation Interconnection[1] (see BPM-015 r26)) MISO performed Transmission Studies for DER interconnections under the MISO ad-hoc process. Under this MISO ad hoc process MISO would be notified of the need for study and perform their own screening with their own criteria. Once they had determined the need for study, MISO would provide the Company with a study agreement for each study that was to be performed and then performed the study. Under the new MISO process, the studies are now done on a quarterly basis with studies entering their queue to perform studies in the next quarter after they have been screened under MISO's updated criteria (this can be reviewed in the business practice manual linked above).

[1] https://www.misoenergy.org/legal/business-practice-manuals/

Preparer: Michael Ruiz
Title: Sr. Engineer
Department: Distribution
Telephone: 612-330-6771
Date: November 14, 2023

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

Xcel Energy		Information Request No.	4
Docket No.:	E999/CI-16-521		
Response To:	Minnesota Public Utilities Commission		
Requestor:	Sophie Nikitas		
Date Received:	October 27, 2023		

Question:
What is Xcel doing to seek feedback and educate DER Customers about the proposed Xcel Transmission Affected System Study process; including when it is applied, the study guidelines, and why the Daytime Minimum Load threshold is necessary to protect Transmission System reliability?

Response:
Xcel Energy communicated changes to the Transmission Study Process to workgroup stakeholders on August 9, 2023 and also explained why the Daytime Minimum Load threshold is necessary to protect Transmission System reliability. This was prior to the implementation of this for studies in October 2023. Electronic invitations were sent to about 1000+ people on our running invite list for DER issues, and included is the draft PowerPoint presentation as attached to the Nokomis letter. This workgroup was well attended, with about 53 non-Xcel Energy participants. After meeting minutes are approved at the next quarterly DER workgroup meeting, we will file the meeting minutes with the Commission.

At this workgroup, there was no push-back to the Company conducting transmission system impact studies. There were only a couple of questions from participants and those questions were not related to why the Daytime Minimum Load threshold is necessary to protect Transmission System reliability. We also encouraged developers to ask questions and provided responses in a timely manner. In addition, we have more information and resources available in our Xcel Energy Interconnection Developer resources page: Interconnection | Renewable Developer Resources | Xcel Energy[1]. Further, with most CSG developers, we have bi-weekly calls to go over status of projects and concerns of developers. We also review the process for transmission studies with individual developers when this type of study is needed for a given project.

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[1] https://mn.my.xcelenergy.com/s/renewable/developers/interconnection, Documents related to Transmission can be found under: General Resources > Interconnection Technical Requirements > Transmission Affected System Impact Study.

Preparer: Michael Ruiz
Title: Sr. Engineer
Department: Distribution
Telephone: 612-330-6771
Date: November 14, 2023

Xcel Energy®

414 Nicollet Mall
Minneapolis, MN 55401

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November 15, 2023

—Via Electronic Filing—

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

RE: COMPLIANCE FILING – QUARTERLY 2023 REPORT
GENERIC STANDARDS FOR INTERCONNECTION AND OPERATION OF DISTRIBUTED GENERATION FACILITIES
DOCKET NOS. E999/CI-16-521 & E,G002/M-12-383 & E002/M-18-714

Dear Mr. Seuffert:

Northern States Power Company, doing business as Xcel Energy, submits this Quarterly Compliance Report as required by the Minnesota Public Utilities Commission's February 18, 2021 Order Accepting Filing and Denying Request to Exclude Complaints at Order Point 4 and the Notice of Quarterly Reporting Requirements issued on May 12, 2021.

Certain information in Attachment A is nonpublic and is Protected Information that is not in the public version of this filing. For example, pursuant to Minn. Stat. §13.02, subd 9, the pre-incentive installed costs and zip code information is generally nonpublic, consistent with the requirements in Minn. Stat. §216B.1611, subd. 3a(d). Other information may also be nonpublic because in combination with other publicly available information, it could identify specific customers.

Also, consistent with the need to protect "security information" under Minn. Stat. §13.37, subd 1(a), the Company generally does not publicly provide certain combinations of information about its grid including city information and feeder/substation information. This approach has been developed over time and includes the Commission discussion of what type of data to publicly provide in our Service Quality Performance reports, as reflected in our March 30, 2018 filing of our 2017 Annual Report in Docket No. E002/M-18-239 at page 13. This resulted in the Company publicly providing the city, but not also publicly providing the feeder/substation. This approach aligns with the Company's prior practice in this

V. GROUP STUDY

In compliance with the March 2022 Order, Ordering Point 7, Xcel Energy filed a six-month Group Study compliance report on September 30, 2022 in this docket. In this filing, the Company committed to reporting ongoing progress of the Group Study pilot in future MN DIP Quarterly Compliance filings.

From September 2022 through October 31, 2023, a total of 147 applications are currently in or have completed cluster study. Approximately 16 percent of these applications are in System Impact Study, 3 percent are in Facilities Study, 10 percent have received an Interconnection Agreement, 24 percent are on-hold while the previous in-queue project study is complete, and the remaining 46 percent have withdrawn their application.

VI. EQUIPMENT LEAD TIMES

The industry has experienced significant supply chain lead times which have persisted over the past few years and have continued to persist through Q3. The Company is now seeing a substantial increase in equipment lead times for primary metering equipment. Historically, larger DER projects and Solar*Rewards Community applications were required to have metering equipment ordered no later than 32 weeks prior to the in-service date (ISD). As a result of the increase in lead times, in July 2023 we updated the timeline for procurement to require primary metering equipment be ordered no later than 50 weeks prior to the ISD. Secondary metering equipment lead times will remain unchanged.

Transformer availability continues to be a pervasive issue across the entire electric industry and will impact new customer projects for the foreseeable future. Even though the Company is installing oversized transformers when available, sourcing from new manufacturers, expanding our inventory & contracts, and expanding our internal/external transformer rebuild program, we have seen these lead times pushing past 52 weeks. The Company continues to communicate with major builders, developers, key customers, contractors, and community leaders regarding delays as we are made aware of delays. We expect these lead time issues to continue through 2024.

We are committed to working closely with customers and will keep them informed as the situation changes in the coming weeks and months ahead.

VII. TRANSMISSIONS STUDIES

We provide here a high level discussion of transmission studies, and provide further discussion in the last section of this quarterly report. Starting in October 2022, Xcel

Energy implemented the MISO transmission study process for a MISO review and study of DER interconnection applications that have potential to adversely impact the transmission system under the MISO criteria that triggers a MISO review. In Q2, the Company has received its first completed report since the start of this process. Additional reports are currently under review and the Company expects to provide more details on this process in future MN DIP Quarterly reports.

On September 1, 2023, Xcel Energy also implemented an internal Transmission Study Process independent of the MISO Transmission Study process. This internal Transmission Study reviews DER interconnection applications that have potential to adversely impact the transmission system when substation DML is exceeded but less than peak load. The screening process began on September 1, 2023 with studies having been scheduled to begin October 1, 2023. There are currently no applications being studied under the internal Transmission Study process at this time, but applications that trigger the internal transmission study criteria will be flagged and studied quarterly.

VIII. SMART INVERTER IMPLEMENTATION

On March 2, 2023, the Distributed Generation Work Group (DGWG) presented updates to the State of Minnesota Technical Interconnection and Interoperability Requirements (TIIR) for Commission approval, including changes required to move for full implementation of the TIIR to use IEEE 1547-2018 certified inverters. The Commission approved the TIIR changes and on April 11, 2023, issued an Order setting the timeline for adopting these statewide standards into each utility's Technical Specifications Manual (TSM). The implementation of these changes will take place when smart inverters are determined to be "readily available" by the Commission.

Xcel Energy implemented a voluntary interim process to allow developers to have their projects studied using smart inverters. As part of the roll-out, Xcel Energy hosted two office hours summarizing the interim implementation process and outlining the steps developers need to take. Beginning April 3, 2023, smart inverters have been available for applications entering a SIS and in these cases the SIS will utilize the Volt-VAR functionality instead of the fixed Power Factor. This allows time for the developer to procure UL1741SB certified inverters and should not create a manufacturer market advantage or disadvantage. Although not yet fully approved, Xcel Energy's TSM will be utilized for the applications that elect to be studied with the smart inverter Volt-VAR functionality. The planned in-service date for any project using a smart inverter will be after smart inverters are deemed "readily available" and applicable TIIR and TSM are fully approved and in effect. The developer would need to decide prior to the start of the SIS if they want to switch to a smart inverter and modify application prior to signing the SIS

customers to keep their existing incentive allocation. This is a change from the existing practice which requires manual intervention, as typically any increase to the system size would require a new application. Despite the manual processing, the Company was happy to propose this solution for affected customers due to this situation. It is important to note that neither the former customers of Sun Badger nor the Company received benefits from this proposal that they would not have received, had their systems and Solar*Rewards applications been completed appropriately by Sun Badger Solar in the prior program year. The one variance to this statement is that some households would be allowed a slightly increased system size because of discontinued originally specified modules, and this proposal variance from standard operation is a one-time case.

C. Transmission

The Company currently has two processes for determining transmission impacts: The MISO Transmission System Impact Study Process and the Internal Transmission System Impact Study Process.

1. MISO Transmission System Impact Study Process

To ensure regional transmission reliability and deliverability, MISO conducts transmission studies for Xcel Energy in cases where transmission impacts are identified due to interconnecting DER in a substation (i.e., aggregate DER is exceeding the substation peak load, resulting in reverse flow.) This process was implemented in October 1, 2022 under the MISO "Ad hoc Process." As shared at MISO's July 1, 2023 Planning Advisory Committee, MISO has updated their process to perform quarterly studies, a process change that became effective on October 1, 2023. Under the new process, MISO will perform screenings to determine what projects will enter their quarterly study queue under the following conditions:

- Aggregate Substation DER less than 1MW of substation peak load: Project will screen out and not require a MISO Transmission System Impact Study.
- Aggregate Substation DER greater than 1MW but less than 5MW peak load: A 1% Line Rating criteria will be applied with MISO requiring a MISO Transmission System Impact Study for projects exceeding that criterion.
- Aggregate Substation DER greater than 5MW of substation peak load: Project will require a MISO Transmission System Impact Study.

There are currently three substations in MISO's study queue. Two of these studies have been completed. One study resulted in recommended upgrades of approximately $8 million, while the other study resulted in no transmission upgrades being required. As required by MISO, studies have a deposit fee of $60,000 per substation under study and

will take 90 days to complete. At the completion of the study, the results will be communicated to the developers.

2. Internal Transmission System Impact Study Process

Due to the extensive cost of transmission upgrades ($8 million) resulting from the first MISO study analysis and resulting reliability concerns, the Company has determined there is an additional need to conduct an internal Transmission System Impact Study.

As explained at our workgroup meeting on August 9, 2023, we began implementing the internal transmission study process to determine the impacts to Transmission due to interconnecting DER. Any CSG application where the aggregate DER is exceeding substation DML, but is less than peak load, will be studied internally and will not be sent to MISO for additional study. Screening for studies began on September 1, 2023 with quarterly studies beginning as of October 1, 2023. Interconnection applications that have not yet reached the Facilities Study stage by September 1, 2023 may be affected. This study process will impact 42 substations with DER rated at 750kW or greater. Initially, we determined that a study deposit of $60,000 would be required. However, after evaluation, the study deposit was reduced to $45,000 per study, regardless of substation. The internal transmission study will take up to 90 days to complete. At the completion of the study, the results will be communicated to develops.

CONCLUSION

We appreciate the opportunity to provide further information regarding the MN DIP process and applications. We respectfully request the Commission accept this Q3 2023 Quarterly Compliance Report in compliance with the Commission Orders and Notice.

Dated: November 15, 2023

Northern States Power Company

414 Nicollet Mall
Minneapolis, MN 55401

November 28, 2023

—Via Electronic Filing—

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

RE: STAKEHOLDER MINUTES
COMMUNITY SOLAR GARDENS
DOCKET NO. E002/M-13-867

Dear Mr. Seuffert:

Northern States Power Company, doing business as Xcel Energy, submits the attached Compliance information in response to the Commission's February 13, 2015 Order (Order Point 3) submitted in the above-noted docket. Per Commission Order, all agendas, approved minutes and attachments from the Solar*Rewards Community (S*RC) Implementation Workgroup will be filed in eDockets. We note that we have expanded our working group efforts to begin to include all Distributed Energy Resources (DER). Therefore, we include the meeting minutes from the MN DER Implementation Workging group here. Attachment A includes the minutes for our August 9, 2023 workgroup along with the powerpoint pertaining to that meeting, which were approved at the November 15, 2023 workgroup session

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 Kristen Ruud at Kristen.S.Ruud@xcelenergy.com if you have any questions regarding this filing.

Sincerely,
/s/

JESSICA PETERSON
MANAGER, PROGRAM POLICY

Enclosure
c: Service List

MN DER Implementation Workgroup

2023 Quarter Three – August 9, 2023

Meeting Minutes

PRESENT INCLUDE:

Full Name	Organization
Josh Schuman	Amp Energy
Andy Goke	Apadana Solar
Cecelia Hartigan	Apadana Solar
Mat Orner	Apadana Solar
Rachael Acevedo-Hoffmann	Apadana Solar
Ingrid Bjorklund	Bjorklund Law
"BlueSky Electric & Solar"	BlueSky Electric & Solar
Lucas Buchanan	Cedar Creek Energy
Bruce Konewko	Cooperative Energy Futures
Pouya Najmaie	Cooperative Energy Futures
Josephine Hamilton	EDF
Anabel Njoes	Emmons & Olivier Resources, Inc. (EOR)
Jon Richter	Energy Concepts LLC
Evan Carlson	Enterprise Energy
Carly Jaeger	Everlight Solar
Samira Hussaini	Everlight Solar
Courtney O'Connor	Gordian Energy Systems
Andrew Armstrong	Gordian Energy Systems
Jeffrey Barber	Knobelsdorff
Armel Martin	Luminance By Brookfield Renewable
Dave Robinson	McKinstry
Kyle Samejima	Minneapolis Climate Action
John Wachtler	Minnesota Department of Commerce (MN DOC)
Brian Lebens	Minnesota Office of the Attorney General (MN OAG)
John Dybvig	Minnesota Public Utilities Commission (MN PUC)
Tracie Bangert	Minnesota Public Utilities Commission (MN PUC)
Kyle Neal	Minnesota Valley Electric Cooperative
Pa Stelzner	MN PUC CAO
Kim Benjamin	MN Solar
Leah Johnson	MN Solar
Curtis Zaun	MnSEIA (MN Solar Energy Industries Association)
Bridget Clements	N/A
Kevin Burns	N/A
Michael Holmes	New Energy Equity

Matt Van Arkel	New Leaf Energy
Amber Vadnais	Nokomis Energy
Brooke Bestul	Nokomis Energy
David Shaffer	Novel Energy Solutions
Zeeshan Yasin	Novel Energy Solutions
Jose Luciano	PPLSI Business Solutions
David Coughlan	Solar Flow LLC
James McCarten	Solar Landscape
Mouli Vaidyanathan	Solar Pod
Jeff Bertch	Solar Stone
Steve Coleman	Steve Coleman
Umar Ahmed	Sun Renewable Energy
Cara Koontz	SunVest Solar
Donna Pickard	TruNorth Solar
Jackson Cade	US Solar
Luke Gildemeister	US Solar
Ross Abbey	US Solar
Audrey Ochtrup-DeKeyrel	US Solar
Will Kenworthy	Vote Solar
Amy Meister	Xcel Energy
Callie Walsh	Xcel Energy
Casey Anderson	Xcel Energy
Crystal Pomerleau	Xcel Energy
David Craig	Xcel Energy
Dean Schiro	Xcel Energy
Forrest Turner	Xcel Energy
Jacob Hillman	Xcel Energy
James Denniston	Xcel Energy
Jameson Kahl	Xcel Energy
Jeffrey McLean	Xcel Energy
Jessica Peterson	Xcel Energy
Joshua Gutzmann	Xcel Energy
Karl Johnson	Xcel Energy
Katie Dietlin	Xcel Energy
Kerry Klemm	Xcel Energy
Kristen Ruud	Xcel Energy
Leena Kurki	Xcel Energy
Madeline Lydon	Xcel Energy
Matthew Hooley	Xcel Energy
Michael Ruiz	Xcel Energy
Mike Sans Crainte	Xcel Energy

Lastly, Xcel Energy provided reminders and best practices for scheduling Witness Tests.

Transmission System Impact Studies

Xcel Energy also addressed Transmission System Impact Studies as part of a DER application review and provided information on the process. Xcel Energy referenced the PowerPoint slide that showed the process chart for the MISO (Midcontinent Independent System Operator) Transmission studies, and Xcel Energy then described the MISO screening criteria and current status as was communicated by MISO to the IPWG (Interconnection Process Working Group) workgroup on July 1st. MISO had explained that the MISO screening criteria and current process is in accordance with FERC (Federal Energy Regulatory Commission) requirements. Under the MISO process, the need for a MISO transmission System Impact Study for a DER application is triggered by aggregate DER exceeding substation peak load as further detailed in the Q3 PowerPoint slide. The cost is $60,000 per substation studied; and MISO studies are conducted on a quarterly basis.

Then Xcel Energy discussed the new Xcel Energy transmission System Impact Study process, why it was important for maintaining grid reliability, and the requirement for this type of study when aggregate DER is exceeding substation DML but not at a level that would trigger a MISO transmission System Impact Study review. The MISO trigger for review is when the DER exceeds peak substation load. Xcel Energy explained that it would begin its transmission System Impact Studies on September 1st, 2023, with quarterly studies beginning on October 1st, 2023. The initial study deposit for the Xcel Energy transmission System Impact Study would be $60,000 per study but this would cover the cost of all Xcel Energy transmission System Impact Studies conducted within a given quarter. A question was raised to clarify the line rating criteria of the new MISO screening criteria and the answer was that this would vary depending on the transmission line rating. Another question was whether the timing of sending the transmission System Impact Study agreement for funding could be delayed until after the results of the distribution System Impact Studies are presented to the developer. Xcel Energy stated that it would consider this internally and determine whether to change its practice.

C. DESIGN & CONSTRUCTION

Xcel Energy discussed the following:

- Equipment Lead Times associated with Design & Construction.
    - In general, we order material according to ISD and construction timelines
    - Transformers continue to be a challenge and some transformers can be up to or beyond 52–58-week lead time
    - Primary service PT and CT lead time increase from 32 weeks to approx. 50 weeks
    - Covered what the company is doing to be proactive in response to our long transformer lead times. Installing oversized transformers when available, sourcing from new vendors, sourcing transformer components, expanding inventory and entering into longer term contracts, expanding our internal rebuild program.

Transmission Studies

Who: MISO

What: MISO Transmission Studies (TS)

Where: Aggregate DER > Substation peak Load

If substation contains multiple transformers, substation peak load is the sum of the substation transformers

When: Quarterly

Why: Ensure Regional Transmission reliability & deliverability

How: Developer is notified and sent an SOW. Xcel Energy notifies MISO after receiving signed SOW

MISO performs screening to determine if substation will move forward to study stage

Who: Xcel Energy

What: Xcel Energy Transmission Studies (TS)

Where: DER exceeds DML

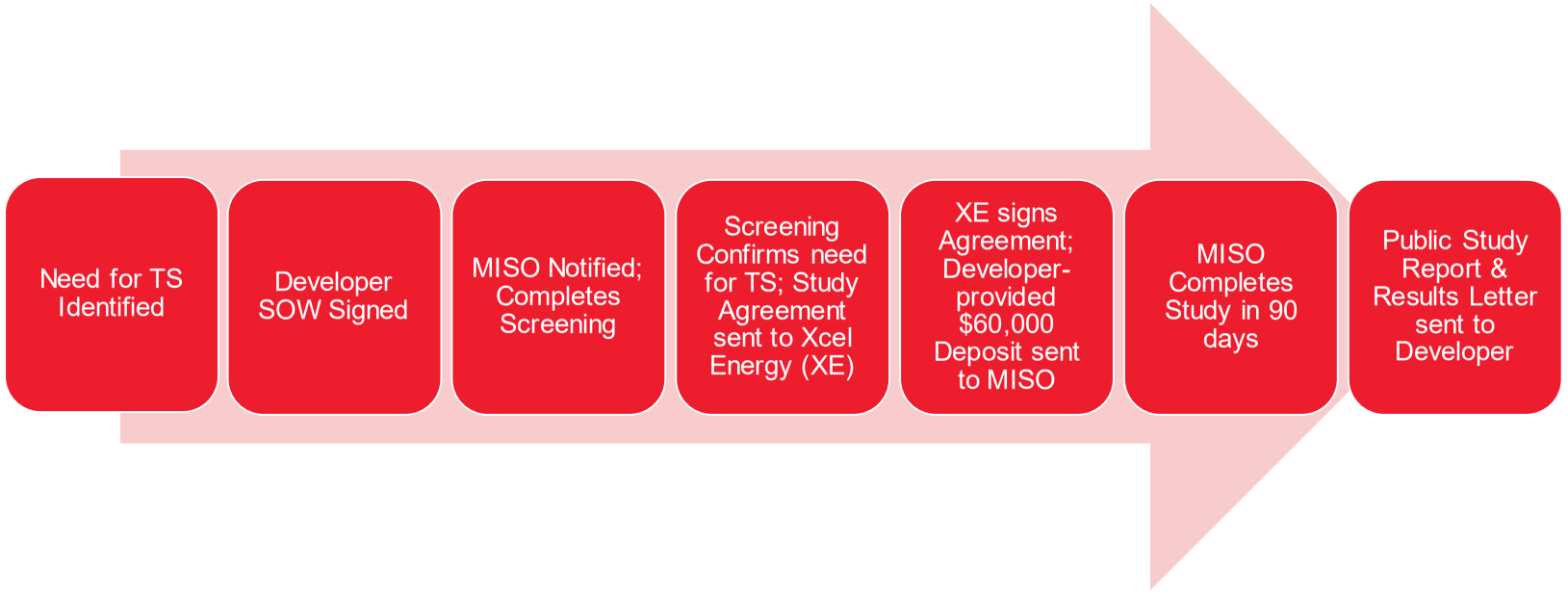
When: Proposal: Quarterly

Why: Ensure Xcel Energy Transmission system reliability

How: Process similar to MISO, but Transmission Planning will be informed after receiving confirmation and agreement of Transmission Study

Transmission Studies

MISO Transmission Study Process



Transmission Studies (TS)

MISO Transmission Study Process

Screening Criteria & Current Status

- MISO Screening is in accordance with their new DER Affected System Impact Study process
  - **Aggregate Substation DER < 1MW of substation peak load**: No TS required
  - **Aggregate Substation DER > 1MW but < 5MW of peak load**: >1% line rating criteria is applied.
  - DER meeting that criteria require TS
  - **Aggregate Substation DER > 5MW of substation peak load**: TS required.
- Currently 5 substations with signed study agreements and currently in study
- 1 study is completed resulting in transmission upgrades estimated to cost ~$8M.

Xcel Energy®

414 Nicollet Mall
Minneapolis, MN 55401

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March 1, 2024

—Via Electronic Filing—

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

RE: COMPLIANCE FILING - 2023 INTERCONNECTIONS
GENERIC STANDARDS FOR INTERCONNECTION AND OPERATION OF
DISTRIBUTED GENERATION FACILITIES
DOCKET NOS. & E,G-002/M-12-383 & E002/M-13-867 & E999/CI-16-521
E002/M-18-714

Dear Mr. Seuffert:

Northern States Power Company, doing business as Xcel Energy, submits this Annual Report as required by the Minnesota Public Utilities Commission's August 13, 2018 Order in these dockets Establishing Updated Interconnection Process and Standard Interconnection Agreement at Order Point 20, the Commission's January 22, 2020 Order in these dockets Establishing Updated Technical Interconnection and Interoperability Requirements at Order Point 9, the Commission's May 12, 2021 Notice in these dockets, the Commission's February 18, 2021 Order Accepting Filing and Denying Request to Exclude Complaints in Docket Nos. E,G002/CI-02-2034 and E,G002/M-12-383 at Order Point 4, the Commission's November 19, 2022 Order in Docket No. E002/M-22-162 at Order Point 7, and the June 20, 2023 and December 12, 2023 Orders in Docket No. E002/M-13-867.

Certain information in Attachment A is nonpublic and is Protected Information that is not in the public version of this filing. For example, pursuant to Minn. Stat. § 13.02, subd 9, the pre-incentive installed costs, zip code and feeder information are generally nonpublic, consistent with the requirements in Minn. Stat. § 216B.1611, subd. 3a(d). Other information may also be nonpublic because in combination with other publicly available information, it could identify specific customers.

Also, consistent with the need to protect "security information" under Minn. Stat. §13.37, subd 1(a), the Company does not publicly provide certain combinations of

D. Transmission Studies

Due to the extensive cost of transmission upgrades ($8 million) resulting from the first MISO study analysis and resulting reliability concerns, the Company has determined there is an additional need to conduct an internal Transmission System Impact Study. Since then, three additional MISO studies have been performed. The findings of those three studies did not result in any transmission upgrades needed.

As explained at our workgroup meeting on August 9, 2023, we began implementing the internal transmission study process to determine the impacts to Transmission due to interconnecting DER. Any CSG application where the aggregate DER is exceeding substation DML, but is less than peak load, will be studied internally and will not be sent to MISO for additional study because these have not met the MISO threshold. Screening for studies began on September 1, 2023 with quarterly studies beginning as of October 1, 2023. Interconnection applications that have not yet reached the Facilities Study stage by September 1, 2023 may be affected. This study process will impact 42 substations with DER rated at 750kW or greater. Initially, we determined that a study deposit of $60,000 would be required. However, after evaluation, the study deposit was reduced to $45,000 per study, regardless of substation. The internal transmission study will take up to 90 days to complete. At the completion of the study, the results will be communicated to develops.

CONCLUSION

We respectfully request the Commission accept this 2023 Annual Report in compliance with the applicable Orders as outlined in Attachment A, Compliance Matrix.

Dated: March 1, 2024

Northern States Power Company

414 Nicollet Mall
Minneapolis, MN 55401

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May 15, 2024

—Via Electronic Filing—

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

RE: COMPLIANCE FILING - 2024 INTERCONNECTIONS
GENERIC STANDARDS FOR INTERCONNECTION AND OPERATION OF
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DOCKET NOS. & E,G-002/M-12-383 & E002/M-13-867 & E999/CI-16-521
E002/M-18-714

Dear Mr. Seuffert:

Northern States Power Company, doing business as Xcel Energy, submits this Annual Report as required by the Minnesota Public Utilities Commission's August 13, 2018 Order in these dockets Establishing Updated Interconnection Process and Standard Interconnection Agreement at Order Point 20, the Commission's January 22, 2020 Order in these dockets Establishing Updated Technical Interconnection and Interoperability Requirements at Order Point 9, the Commission's May 12, 2021 Notice in these dockets, the Commission's February 18, 2021 Order Accepting Filing and Denying Request to Exclude Complaints in Docket Nos. E,G002/CI-02-2034 and E,G002/M-12-383 at Order Point 4, the Commission's November 19, 2022 Order in Docket No. E002/M-22-162 at Order Point 7, and the June 20, 2023 and December 12, 2023 Orders in Docket No. E002/M-13-867.

Certain information in Attachment A is nonpublic and is Protected Information that is not in the public version of this filing. For example, pursuant to Minn. Stat. § 13.02, subd 9, the pre-incentive installed costs, zip code and feeder information are generally nonpublic, consistent with the requirements in Minn. Stat. § 216B.1611, subd. 3a(d). Other information may also be nonpublic because in combination with other publicly available information, it could identify specific customers.

Also, consistent with the need to protect "security information" under Minn. Stat. §13.37, subd 1(a), the Company does not publicly provide certain combinations of

ordered no later than 32 weeks prior to the in-service date (ISD). As a result of the increase in lead times, we updated the timeline for procurement in July of 2023 to require primary metering equipment be ordered no later than 50 weeks prior to the ISD. Secondary metering equipment lead times remain unchanged.

Transformer availability continues to be a pervasive issue across the entire electric industry and will impact new customer projects for the foreseeable future. Even though the Company is installing oversized transformers when available, sourcing from new manufacturers, expanding our inventory & contracts, expanding our internal/external transformer rebuild program, and are working with peer utilities, we have seen these lead times pushing past 52 weeks. The Company continues to communicate with major builders, developers, key customers, contractors, and community leaders regarding delays as we are made aware of delays.

We expect these lead time issues to continue through 2024 and have seen a plateau in the estimated lead times, stabilizing at 52 weeks for transformers and 50 weeks for primary metering equipment. This same equipment is used for DER interconnections as well as for retail customers who do not have DER equipment. Accordingly, this supply chain issue impacts both retail and DER interconnection services.

B. Transmission Studies

Due to the extensive cost of transmission upgrades ($8 million) resulting from the first MISO study analysis and resulting reliability concerns, the Company has determined there is an additional need to conduct an internal Transmission System Impact Study. As explained at our workgroup meeting on August 9, 2023, we began implementing the internal transmission study process to determine the impacts to Transmission due to interconnecting DER. Any CSG application where the aggregate DER is exceeding substation DML, but is less than peak load, will be studied internally and will not be sent to MISO for additional study because these have not met the MISO threshold. Screening for studies began on September 1, 2023 with quarterly studies beginning as of October 1, 2023. Interconnection applications that have not yet reached the Facilities Study stage by September 1, 2023 may be affected. This study process will impact 42 substations with DER rated at 750kW or greater. Initially, we determined that a study deposit of $60,000 would be required. However, after evaluation, the study deposit was reduced to $45,000 per study, regardless of substation. The internal transmission study will take up to 90 days to complete. At the completion of the study, the results will be communicated to developers.

In the past quarter, there have been no internal transmission studies performed.

Xcel Energy®

414 Nicollet Mall
Minneapolis, MN 55401

PUBLIC DOCUMENT
NOT PUBLIC DATA HAS BEEN EXCISED

August 15, 2024

—Via Electronic Filing—

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

RE: COMPLIANCE FILING - 2024 INTERCONNECTIONS
GENERIC STANDARDS FOR INTERCONNECTION AND OPERATION OF
DISTRIBUTED GENERATION FACILITIES
DOCKET NOS. & E,G-002/M-12-383 & E002/M-13-867 & E999/CI-16-521
E002/M-18-714

Dear Mr. Seuffert:

Northern States Power Company, doing business as Xcel Energy, submits this Quarterly Report as required by the Minnesota Public Utilities Commission's August 13, 2018 Order in these dockets Establishing Updated Interconnection Process and Standard Interconnection Agreement at Order Point 20, the Commission's January 22, 2020 Order in these dockets Establishing Updated Technical Interconnection and Interoperability Requirements at Order Point 9, the Commission's May 12, 2021 Notice in these dockets, the Commission's February 18, 2021 Order Accepting Filing and Denying Request to Exclude Complaints in Docket Nos. E,G002/CI-02-2034 and E,G002/M-12-383 at Order Point 4, the Commission's November 19, 2022 Order in Docket No. E002/M-22-162 at Order Point 7, and the June 20, 2023 and December 12, 2023 Orders in Docket No. E002/M-13-867.

Certain information in Attachment A is nonpublic and is Protected Information that is not in the public version of this filing. For example, pursuant to Minn. Stat. § 13.02, subd 9, the pre-incentive installed costs, zip code and feeder information are generally nonpublic, consistent with the requirements in Minn. Stat. § 216B.1611, subd. 3a(d). Other information may also be nonpublic because in combination with other publicly available information, it could identify specific customers.

Also, consistent with the need to protect "security information" under Minn. Stat. §13.37, subd 1(a), the Company does not publicly provide certain combinations of

metering equipment. This same equipment is used for DER interconnections as well as for retail customers who do not have DER equipment. Accordingly, this supply chain issue impacts both retail and DER interconnection services.

C. Transmission Studies

Due to the extensive cost of transmission upgrades ($8 million) resulting from the first MISO study analysis and resulting reliability concerns, the Company has determined there is an additional need to conduct an internal Transmission System Impact Study. As explained at our workgroup meeting on August 9, 2023, we began implementing the internal transmission study process to determine the impacts to Transmission due to interconnecting DER. Any CSG application where the aggregate DER is exceeding substation DML, but is less than peak load, will be studied internally and will not be sent to MISO for additional study because these have not met the MISO threshold. Screening for studies began on September 1, 2023 with quarterly studies beginning as of October 1, 2023. Interconnection applications that have not yet reached the Facilities Study stage by September 1, 2023 may be affected. This study process will impact 42 substations with DER rated at 750kW or greater. Initially, we determined that a study deposit of $60,000 would be required. However, after evaluation, the study deposit was reduced to $45,000 per study, regardless of substation. The internal transmission study will take up to 90 days to complete. At the completion of the study, the results will be communicated to developers.

In the past quarter, there have been no internal transmission studies performed.

VII. COMMUNITY SOLAR GARDEN PLANNED OUTAGES

In addition, the Commission's December 12, 2023 Order in Docket No. E002/M-13-867 granted Xcel Energy's motion to streamline reporting requirements for the Solar*Rewards Community program. This Order requires Xcel Energy to provide reporting on Planned Outages for community solar gardens (CSGs) in the quarterly MN DIP reporting and file a copy of this reporting in Docket No. E-002/M-13-867. This information is provided in Attachment G, CSG Planned Outage Reporting.

CONCLUSION

We respectfully request the Commission accept this Q2 2024 Quarterly Report in compliance with the applicable Orders as outlined in Attachment A, Compliance Matrix.

Dated: August 15, 2024

Northern States Power Company

Xcel Energy®

414 Nicollet Mall
Minneapolis, MN 55401

September 19, 2024

—Via Electronic Filing—

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

RE: STAKEHOLDER MINUTES
COMMUNITY SOLAR GARDENS
DOCKET NO. E002/M-13-867

Dear Mr. Seuffert:

Northern States Power Company, doing business as Xcel Energy, submits the attached Compliance information in response to the Commission's February 13, 2015 Order (Order Point 3) submitted in the above-noted docket. Per Commission Order, all agendas, approved minutes and attachments from the Solar*Rewards Community (S*RC) Implementation Workgroup will be filed in eDockets. We note that we have expanded our working group efforts to begin to include all Distributed Energy Resources (DER). Therefore, we include the meeting minutes from the MN DER Implementation Workging group here. Attachment A includes the approved meeting minutes for our May 15, 2024 workgroup along with the powerpoint pertaining to that meeting.

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 Kristen Ruud at Kristen.S.Ruud@xcelenergy.com if you have any questions regarding this filing.

Sincerely,
/s/

JESSICA PETERSON
MANAGER, PROGRAM STRATEGY AND PERFORMANCE

Enclosure
c: Service List

MN DER Stakeholder Workgroup

2024 Quarter Two – May 15, 2024

Meeting Minutes

PRESENT INCLUDE:

Full Name	Organization
Casey Anderson	Xcel Energy
Andrew Damitio	Unverified
Anna Danielski	Unverified
Ankita Ashrit	Xcel Energy
Austin	Unverified
Bella Montague	Unverified
Ben Gregory	Dynamic Energy
Ben Ransom	Unverified
Patrick Berger	Xcel Energy
Braden Salvati	Unverified
Brandon Smithwood	Unverified
Brant Thomas	Unverified
Brian Dolan	Unverified
Brooke Bestul	Nokomis Energy
Ryan Bruers	Xcel Energy
Cara Koontz	Unverified
Carly Jaeger	Unverified
Carissa Cavalieri	Xcel Energy
Colin O'Neil	Unverified
John-Michael Cross	Department of Commerce
Dan	Guest
Danielle DeMarre	All Energy Solar
Dave Coughlan	Unverified
James Denniston	Xcel Energy
Bridget Dockter	Xcel Energy
Donna	TruNorth Solar
Derek Duran	PUC
Elliott Wiegman	Unverified
Eric Pasi	Enterprise Energy
Erick Sipila	Sisu Solar
Erin Curran	Unverified
Evan	Unverified
Anastasia Garth	Unverified
Gary Winters	Unverified

Full Name	**Organization**
Gabriel Gauderman	Unverified
Tami Gunderzik	Xcel Energy
Hannah Boudreau	Unverified
Jeff Horst	Unverified
Karl Johnson	Xcel Energy
Joseph Nishida	Unverified
Ken Valley	Unverified
Kevin Cray	Unverified
Kim Benjamin	MN Solar
Madeleine Klein	ENGIE North America
Kerry Klemm	Xcel Energy
Leena Kurki	Xcel Energy
Kyle Samejima	Cooperative Energy Futures
Lionel Durand	Unverified
Lucas Buchanan	Cedar Creek Energy
Luke Glidemeister	US Solar
Maggie Kaynor	Unverified
Matt Van Arkel	Unverified
Megan Spear	All Energy Solar
Mena Kaehler	Unverified
Michael Cathcart	Unverified
Mike Kampmeyer	Unverified
MK	New Leaf Energy
Hannah Moore	ENGIE North America
Adwaid Nambiar	Xcel Energy
Nathan Smelker	Unverified
Nikolas Vivier	Unverified
Paige Knutsen	MEEA
Jessica Peterson	Xcel Energy
Phillip Truax	Unverified
Ryan Pierce	Xcel Energy
Pouya	Unverified
Tamara Rogers	Xcel Energy
Ross Abbey	US Solar
Michael Ruiz	Xcel Energy
Russel Gilberg	Energy Concepts
Russell Goetze	Unverified
Kristen Ruud	Xcel Energy
Samira H	Unverified
Mike Sans Crainte	Xcel Energy

Full Name	Organization
Sare	Unverified
Dean Schiro	Xcel Energy
Sido Shira	Unverified
Michael Siglin Jr.	Unverified
Stephanie Rogalsky	Unverified
Steve Chan	Unverified
Steve Coleman	Unverified
Peter Teigland	COMM
Tim Rudnicki	Unverified
Makaela Truner	Unverified
Violeta Vidakovic	Xcel Energy
Vince Robinson	DSI
Callie Walsh	Xcel Energy
Brandon Wellcome	Xcel Energy
Wendy Vorasane	Unverified
Zeeshan Yasin	Unverified
Corbin Donner	Xcel Energy
Adwaid Nambiar	Xcel Energy
Vlad	Unverified
Aileen Cole	Unverified
Chua Xiong	Xcel Energy
William Waldron	Unverified

Total Number of Participants: 97

Total Number of Organizations: At least 5+

AGENDA

1:00pm Welcome & Meeting Logistics
1:05pm On-Site Programs
1:35pm All MN DER Interconnections
2:45pm Solar*Rewards Community
2:50pm Closing Remarks

WELCOME & MEETING LOGISTICS

Xcel Energy welcomed stakeholders to the meeting and opened it with logistical items.

PRIORITY AND GENERAL QUEUES – AND NEW DOCKET ON CAPACITY RESERVATION

Commission's April 15, 2024 order in Docket 16 -521 requires two queues for Xcel Energy – a "Priority" queue and a "General" queue. Those applications in the Priority Queue have priority over those in the General queue that have not yet started a System Impact Study nor have a signed Interconnection Agreement. Priority queue includes those "customer sited" DER projects up to 40 kW that comply with the 120% rule, as well as those applications that participate in the Solar on Schools and Solar on Public Building programs. Commission has opened new Docket 24-176 to address issues on capacity reservation for specific types of DER projects. Initial comments due June 7, and Reply comments due June 28.

TRANSMISSION STUDY PROCESS UPDATES

GENERAL

Developers flagged for transmission studies can opt to wait until receiving their distribution System Impact Studies to decide whether to move forward with a transmission study or withdraw. Developer still has 15 business day to decide to move forward and sign SOW once distribution SIS results are received.

INTERNAL TRANSMISSION STUDY (ITS)

Study deposit was reduced from $45,000 to $33,000. Projects entering ITS have until June 23, 2024, to fund study. True-ups will be provided after this date. Projects with signed SOWs and funded will be studied starting on July 1, 2024

MISO

Quarterly cadence began October 1, 2023, and the next screening closing date is June 3, 2024. Developers can refer to MISO Distribution website for upcoming milestones under the DER AFS cycle schedules. Note that screening timeline begins prior to the 90 day study timeline.

DESIGN & CONSTRUCTION

Xcel Energy designers become involved in projects when a study has determined upgrades are required for an Interconnection Agreement (IA). Inform your designers when an IA requiring construction upgrades has been signed. After an IA requiring upgrades has been executed designers will submit an invoice with a Statement of Work (SOW) that must be signed and fully funded to move forward. If you are not receiving the invoice and SOW from your designers, please ask. The site contact will be notified when Xcel Energy's required construction upgrades are complete. Designers should only be contacted after an Interconnection Agreement has been executed, unless a meeting has been scheduled by the program management office.

Transmission Study Process Updates

General

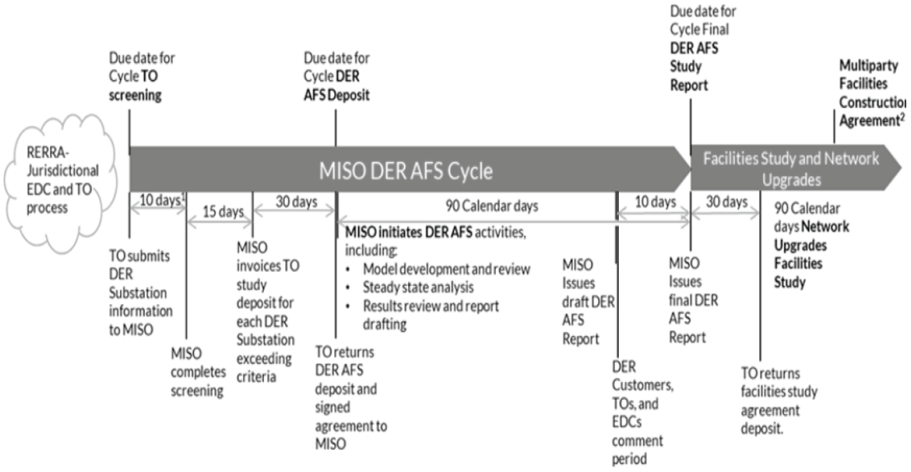
- Developers flagged for transmission studies can opt to wait until receiving their distribution System Impact Studies to decide whether to move forward with a transmission study or withdraw.
  - Developer still has 15 business day to decide to move forward and sign SOW once distribution SIS results are received.

Internal Transmission Study (ITS)

- Study deposit was reduced from $45,000 to $33,000.
- Projects entering ITS have until June 23, 2024, to fund study
  - True-ups will be provided after this date
- Projects with signed SOWs and funded will be studied starting on July 1, 2024

Transmission Study Process Updates
MISO

- MISO Study quarterly cadence began October 1, 2023
- Next screening window closing date: June 3, 2024
- MISO milestone dates can be seen at Distribution (misoenergy.org)[1] under Quarterly DER AFS Study Cycle Schedules
  - Note: Screening timeline begins prior to the 90-calendar day study timeline



1 https://www.misoenergy.org/planning/resource-utilization/distribution/

Xcel Energy®

414 Nicollet Mall
Minneapolis, MN 55401

December 19, 2024

—Via Electronic Filing—

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

RE: STAKEHOLDER MINUTES
COMMUNITY SOLAR GARDENS
DOCKET NO. E002/M-13-867

Dear Mr. Seuffert:

Northern States Power Company, doing business as Xcel Energy, submits the attached Compliance information in response to the Commission's February 13, 2015 Order (Order Point 3) submitted in the above-noted docket. Per Commission Order, all agendas, approved minutes and attachments from the Solar*Rewards Community (S*RC) Implementation Workgroup will be filed in eDockets. We note that we have expanded our working group efforts to begin to include all Distributed Energy Resources (DER). Therefore, we include the meeting minutes from the MN DER Implementation Workging group here. Attachment A includes the approved meeting minutes for our September 4, 2024 workgroup along with the powerpoint pertaining to that meeting.

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 Kristen Ruud at Kristen.S.Ruud@xcelenergy.com if you have any questions regarding this filing.

Sincerely,
/s/

JESSICA PETERSON
MANAGER, PROGRAM POLICY

Enclosure
c: Service List

MN DER Stakeholder Workgroup

2024 Quarter Three – September 4, 2024

Meeting Minutes

PRESENT INCLUDE:

Full Name	Organization
Casey Anderson	Xcel Energy
Andrew Damitio	Unverified
Anna Danielski	Unverified
Ankita Ashrit	Xcel Energy
Austin	Unverified
Bella Montague	Unverified
Ben Gregory	Dynamic Energy
Ben Ransom	Unverified
Patrick Berger	Xcel Energy
Braden Salvati	Unverified
Brandon Smithwood	Unverified
Brant Thomas	Unverified
Brian Dolan	Unverified
Brooke Bestul	Nokomis Energy
Ryan Bruers	Xcel Energy
Cara Koontz	Unverified
Carly Jaeger	Unverified
Carissa Cavalieri	Xcel Energy
Colin O'Neil	Unverified
John-Michael Cross	Department of Commerce
Dan	Guest
Danielle DeMarre	All Energy Solar
Dave Coughlan	Unverified
James Denniston	Xcel Energy
Bridget Dockter	Xcel Energy
Donna	TruNorth Solar
Derek Duran	PUC
Elliott Wiegman	Unverified
Eric Pasi	Enterprise Energy
Erick Sipila	Sisu Solar
Erin Curran	Unverified
Evan	Unverified
Anastasia Garth	Unverified
Gary Winters	Unverified

Full Name	Organization
Gabriel Gauderman	Unverified
Tami Gunderzik	Xcel Energy
Hannah Boudreau	Unverified
Jeff Horst	Unverified
Karl Johnson	Xcel Energy
Joseph Nishida	Unverified
Ken Valley	Unverified
Kevin Cray	Unverified
Kim Benjamin	MN Solar
Madeleine Klein	ENGIE North America
Kerry Klemm	Xcel Energy
Leena Kurki	Xcel Energy
Kyle Samejima	Cooperative Energy Futures
Lionel Durand	Unverified
Lucas Buchanan	Cedar Creek Energy
Luke Glidemeister	US Solar
Maggie Kaynor	Unverified
Matt Van Arkel	Unverified
Megan Spear	All Energy Solar
Mena Kaehler	Unverified
Michael Cathcart	Unverified
Mike Kampmeyer	Unverified
MK	New Leaf Energy
Hannah Moore	ENGIE North America
Adwaid Nambiar	Xcel Energy
Nathan Smelker	Unverified
Nikolas Vivier	Unverified
Paige Knutsen	MEEA
Jessica Peterson	Xcel Energy
Phillip Truax	Unverified
Ryan Pierce	Xcel Energy
Pouya	Unverified
Tamara Rogers	Xcel Energy
Ross Abbey	US Solar
Michael Ruiz	Xcel Energy
Russel Gilberg	Energy Concepts
Russell Goetze	Unverified
Kristen Ruud	Xcel Energy
Samira H	Unverified
Mike Sans Crainte	Xcel Energy

Full Name	Organization
Sare	Unverified
Dean Schiro	Xcel Energy
Sido Shira	Unverified
Michael Siglin Jr.	Unverified
Stephanie Rogalsky	Unverified
Steve Chan	Unverified
Steve Coleman	Unverified
Peter Teigland	COMM
Tim Rudnicki	Unverified
Makaela Truner	Unverified
Violeta Vidakovic	Xcel Energy
Vince Robinson	DSI
Callie Walsh	Xcel Energy
Brandon Wellcome	Xcel Energy
Wendy Vorasane	Unverified
Zeeshan Yasin	Unverified
Dena Webster	Unverified
Donna	TruNorth Solar
Chua Xiong	Xcel Energy
Cleveland Silas	Xcel Energy

Total Number of Participants: 97

Total Number of Organizations: At least 5+

AGENDA

1:00pm Welcome & Meeting Logistics
1:05pm On-Site Programs
1:35pm All MN DER Interconnections
2:45pm Solar*Rewards Community
2:50pm Closing Remarks

WELCOME & MEETING LOGISTICS

Xcel Energy welcomed stakeholders to the meeting and opened it with logistical items.

APPROVAL OF MINUTES

Xcel Energy reiterated that stakeholders are expected to have reviewed the Meeting Minutes and are encouraged to refer to the Meeting Minutes for reference as needed. No workgroup attendees objected to the September 4 Quarter Three Stakeholder Workgroup Meeting Minutes, and these were therefore approved.

Priority Queue have priority over those in the General queue that have not yet started a System Impact Study nor have a signed Interconnection Agreement. Priority queue includes those "customer sited" DER projects up to 40 kW that comply with the 120% rule, as well as those applications that participate in the Solar on Schools and Solar on Public Building programs. Commission has opened new Docket 24-176 to address issues on capacity reservation for specific types of DER projects. Initial comments due June 7, and Reply comments due June 28.

Transmission Study Process Updates

Developers flagged for transmission studies can opt to wait until receiving their distribution System Impact Studies to decide whether to move forward with a transmission study or withdraw. Developer still has 15 business day to decide to move forward and sign SOW once distribution SIS results are received.

MISO Transmission Study

Transmission Study deposits will be collected after MISO completes their screening and confirms the need for a study. Note: Study agreements will still be provided and signed prior to MISO being notified.

Developers will have 15 business days to provide study deposits after MISO provides their confirmation. MISO milestone dates can be seen at misoenergy.org under Quarterly DER AFS Study Cycle Schedules. Screening timeline begins prior to the 90-calendar day study timeline.

Internal Transmission Study (ITS)

Beginning in Q4, developers requiring an ITS will have 23 business days (15 business days + 8 business days automatic extension) to sign the Transmission SIS agreements and fund the study.

The cutoff for next calendar quarter's study is the 20th calendar date of the third month of the given calendar quarter. Studies that are signed and funded on or before the 20th calendar date will qualify to be part of the ITS for the next calendar quarter. Studies that are signed and funded after the 20th calendar date would qualify to be part of the ITS for the quarter after the next calendar quarter.

Projects can still opt to wait until distribution SIS is completed, although they may have to wait until the quarter after the next calendar quarter to enter ITS. Projects that opt to be studied in parallel will be studied in the next quarter.

Three Phase Repeat Trip Charge Pilot

Effective 8/1/2024, the Three-Phase Repeat Trip Charge pilot was marked as complete and Xcel Energy will no longer charge for repeat trips at this time. The pilot was successful, seeing an increase in the pass-first-time percentages, from 50%

Transmission Study Process Updates

Internal Transmission Study (ITS)

- Beginning in the fourth quarter, developers requiring an ITS will have 23 Business days (15 Business days + 8 Business days automatic extension) to sign Transmission SIS Agreements and fund the study.
- Cutoff for next calendar quarter's study is the 20th calendar date of the second month of the given calendar quarter.
  - Studies that are signed and funded on or before the 20th calendar date will qualify to be part of the ITS for the next calendar quarter.
  - Studies that are signed and funded after the 20th calendar date would qualify to be part of the ITS for the quarter after the next calendar quarter.
- Projects can still opt to wait until distribution SIS is completed.
  - May have to wait until the quarter after the next calendar quarter to enter ITS
  - Projects that opt to be studied in parallel will be studied in the next quarter.

Transmission Study Process Updates

MISO

- Study deposits will be collected after MISO completes their screening and confirms the need for a study.
  - Note: Study agreements will still be provided and signed prior to MISO being notified.
- Developers will have 15 business days to provide study deposits after MISO provides their confirmation
- ***Reminder*** – MISO milestone dates can be seen at Distribution(misoenergy.org)[1] under Quarterly DER AFS Study Cycle Schedules
  - Note: Screening timeline begins prior to the 90-calendar day study timeline

1 https://www.misoenergy.org/planning/resource-utilization/distribution/

Attachment 6: System Impact Study Agreement

THIS AGREEMENT is made and entered on Jun 14, 2024 by and between , a [[SertifiLG_1]] organized and existing under the laws of the State of Minnesota, ("Interconnection Customer"), and Northern States Power Company, a Minnesota corporation, doing business as Xcel Energy ("Area EPS Operator"). Interconnection Customer and the Area EPS Operator each may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, the Interconnection Customer is proposing to develop a Distributed Energy Resource (DER) or generating capacity addition to an existing DER consistent with the Interconnection Application completed by the Interconnection Customer on **10/13/2023**; and

WHEREAS, the Interconnection Customer desires to interconnect the DER with the Area EPS Operator's electric system;

WHEREAS, the Interconnection Customer has requested the Area EPS Operator to perform a system impact study(s) to assess the impact of interconnecting the DER with the Area EPS Operator's electric System, and potential Affected System(s);

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agreed as follows:

1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated or the meanings specified in the standard Minnesota Distributed Energy Resources Interconnection Procedures (MN DIP.)

2.0 The Interconnection Customer elects and the Area EPS Operator shall cause to be performed a system impact study(s) consistent with the MN DIP. The scope of a system impact study shall be subject to the assumptions set forth in this Agreement; including Attachment A.

3.0 A system impact study will be based upon the technical information provided by Interconnection Customer in the Interconnection Application. The Area EPS Operator reserves the right to request additional technical information from the Interconnection Customer as may reasonably become necessary consistent with Good Utility Practice during the course of the system impact study.

(Continued on Sheet No. 10-233)

MINNESOTA DISTRIBUTED ENERGY RESOURCES INTERCONNECTION PROCESS (MN DIP)

4.0 A system impact study may, as necessary, consist of a short circuit analysis, a stability analysis, a power flow analysis, voltage drop and flicker studies, protection and set point coordination studies, and grounding reviews. A system impact study shall state the assumptions upon which it is based, state the results of the analyses, and provide the requirement or potential impediments to providing the requested interconnection service, including a preliminary indication of the cost and length of time that would be necessary to correct any problems identified in those analyses and implement the interconnection. A system impact study shall provide a list of facilities that are required as a result of the Interconnection Application and non-binding good faith estimates of cost responsibility and time to construct.

5.0 A distribution system impact study shall incorporate a distribution load flow study, an analysis of equipment interrupting ratings, protection coordination study, voltage drop and flicker studies, protection and set point coordination studies, grounding reviews, and the impact on electric system operation, as necessary.

6.0 Affected Systems may participate in the preparation of a system impact study, with a division of costs among such entities as they may agree. All Affected Systems shall be afforded an opportunity to review and comment upon a system impact study that covers potential adverse system impacts on their electric systems.

7.0 If the Area EPS Operator uses a queuing procedure for sorting or prioritizing projects and their associated cost responsibilities for any required Network Upgrades, the system impact study shall consider all Distributed Energy Resources (and with respect to paragraph 7.3 below, any identified Upgrades associated with such higher queued interconnection) that, on the date the system impact study is commenced –

7.1 Are directly interconnected with the Area EPS Operator's electric system; or

7.2 Are interconnected with Affected Systems and may have an impact on the proposed interconnection; and

7.3 Have a pending higher queued Interconnection Application to interconnect with the Area EPS Operator's electric system.

8.0 A deposit of the equivalent of the good faith estimated cost of a distribution system impact study and the good faith estimated cost of a transmission system impact study shall be required from the Interconnection Customer when the signed Agreement is provided to the Area EPS Operator.

9.0 Any study fees shall be based on the Area EPS Operator's actual costs and will be invoiced to the Interconnection Customer within 20 Business Days after the study is completed and delivered and will include a summary of professional time.

10.0 The Interconnection Customer must pay any study costs that exceed the deposit without interest within 20 Business Days on receipt of the invoice or resolution of any dispute. If the deposit exceeds the invoiced fees, the Area EPS Operator shall refund such excess within 20 Business Days of the invoice without interest.

(Continued on Sheet No. 10-234)

11.0 Governing Law, Regulatory Authority, and Rules

The validity, interpretation and enforcement of this Agreement and each of its provisions shall be governed by the laws of the state of Minnesota. This Agreement is subject to all Applicable Laws and Regulations. Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, or regulations of a Governmental Authority.

12.0 Amendment

The Parties may amend this Agreement by a written instrument duly executed by both Parties.

13.0 No Third-Party Beneficiaries

This Agreement is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and where permitted, their assigns.

14.0 Waiver

14.1 The failure of a Party to this Agreement to insist, on any occasion, upon strict performance of any provision of this Agreement will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.

14.2 Any waiver at any time by either Party of its rights with respect to this Agreement shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, duty of this Agreement. Termination or default of this Agreement for any reason by Interconnection Customer shall not constitute a waiver of the Interconnection Customer's legal rights to obtain an interconnection from the Area EPS Operator. Any waiver of this Agreement shall, if requested, be provided in writing.

15.0 Multiple Counterparts

This Agreement may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument. Electronic signatures are acceptable if the Area EPS Operator has made such a determination pursuant to MN DIP 1.2.1.1.

16.0 No Partnership

This Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon either Party. Neither Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Party.

(Continued on Sheet No. 10-235)

17.0 Severability

If any provision or portion of this Agreement shall for any reason be held or adjudged to be invalid or illegal or unenforceable by any court of competent jurisdiction or other Governmental Authority, (1) such portion or provision shall be deemed separate and independent, (2) the Parties shall negotiate in good faith to restore insofar as practicable the benefits to each Party that were affected by such ruling, and (3) the remainder of this Agreement shall remain in full force and effect.

18.0 Subcontractors

Nothing in this Agreement shall prevent a Party from utilizing the services of any subcontractor as it deems appropriate to perform its obligations under this Agreement; provided, however, that each Party shall require its subcontractors to comply with all applicable terms and conditions of this Agreement in providing such services and each Party shall remain primarily liable to the other Party for the performance of such subcontractor.

18.1 The creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under this Agreement. The hiring Party shall be fully responsible to the other Party for the acts or omissions of any subcontractor the hiring Party hires as if no subcontract had been made; provided, however, that in no event shall the Area EPS Operator be liable for the actions or inactions of the Interconnection Customer or its subcontractors with respect to obligations of the Interconnection Customer under this Agreement. Any applicable obligation imposed by this Agreement upon the hiring Party shall be equally binding upon, and shall be construed as having application to, any subcontractor of such Party.

18.2 The obligations under this article will not be limited in any way by any limitation of subcontractor's insurance.

19.0 Inclusion ofArea EPS Operator Tariffs and Rules

The interconnection services provided under this Agreement shall at all times be subject to the terms and conditions set forth in the tariff schedules and rules applicable to the electric service provided by the Area EPS Operator, which tariff schedules and rules are hereby incorporated into this Agreement by this reference. Notwithstanding any other provisions of this Agreement, the Area EPS Operator shall have the right to unilaterally file with the Minnesota Public Utilities Commission, pursuant to the Commission's rules and regulations, an application for change in rates, charges, classification, service, tariff, or rule or any agreement relating thereto. The Interconnection Customer shall also have the right to unilaterally file with the Minnesota Public Utilities Commission, pursuant to the Commission's rules and regulations, an application for change in rates, charges, classification, service, tariff, or rule or any agreement relating thereto. Each Party shall be have the right to protest any such filing by the other Party and/or to participate fully in any proceeding before the Minnesota Public Utilities Commission in which such modifications may be considered, pursuant to the Commission's rules and regulations.

(Continued on Sheet No. 10-236)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

MINNESOTA DISTRIBUTED ENERGY RESOURCES INTERCONNECTION PROCESS (MN DIP)
(Continued)

Section No. 10
Original Sheet No. 236

IN WITNESS THEREOF, the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.

Northern States Power Company, a Minnesota corporation **(Area EPS Operator)**	_____ **(Interconnection Customer)**
Signed: _____	Signed: _____
Name (Printed): _____	Name (Printed): _____
Title: _____	Title: _____

Amendment

As allowed by paragraph 12.0 above, the Parties have agreed to amend this Agreement. With the signature of the Parties above, the Parties have agreed to this Amendment.

If the project subject to this Agreement requires an Xcel Energy Internal transmission system impact study (and not a MISO transmission study), the deposit referred to in paragraph 8.0 for the good faith estimated cost of such a transmission system impact study shall be paid, and this transmission System Impact Study Agreement needs to be signed by the Interconnection Customer, within 15 Business Days after the Company tenders to the Interconnection Customer this transmission System Impact Study Agreement. The Parties agree to an automatic extension of these deadlines by adding 8 additional Business Days to the deadlines for signing and funding. A Business Day ends at 4:30pm local time in St. Paul, Minnesota. Timely payment is of the essence. The Parties agree that any failure of the Interconnection Customer to make timely payment of this amount, or to sign this Agreement, shall cause the above application to lose its position in queue and to be withdrawn.

Within any given calendar quarter, where this transmission System Impact Study Agreement has been tendered on or before the 20th calendar date of the third month of such quarter, and the Interconnection Customer timely makes payment and timely signs this Agreement, then the project would qualify to be part of the Xcel Energy internal transmission System Impact Study for the next calendar quarter. Within any given calendar quarter, where this transmission System Impact Study Agreement has been tendered after the 20th calendar date of the third month of such quarter, and the Interconnection Customer timely makes payment and timely signs this Agreement, then the project would qualify to be part of the Xcel Energy internal transmission System Impact Study for the quarter after the next calendar quarter.

(Continued on Sheet No. 10-237)

Attachment 6: System Impact Study Agreement (cont'd)

Attachment A

Assumptions Used in Conducting the System Impact Study

The system impact study shall be based upon the following assumptions:

1) Designation of Point of Common Coupling and configuration to be studied.
2) Designation of alternative Points of DER Interconnection and configuration.

1) and 2) are to be completed by the Interconnection Customer. Other assumptions (listed below) are to be provided by the Interconnection Customer and the Area EPS Operator. The Area EPS Operator shall use the Reference Point for Applicability which is either the Point of Common Coupling or the Point(s) of DER Interconnection as described in IEEE 1547.

Additional DER technical data required for System Impact Study

Pursuant to above par. 8.0 and MN DIP 4.3.6, this is for a transmission System Impact Study and may also be part of a cluster study. The Cluster Study Guidelines attachment to this transmission System Impact Study Agreement are part of the transmission System Impact Study Agreement. This transmission System Impact Study, if part of a cluster study, would include one or more other projects.

- Consistent with tariff sheet 10-233, par. 8.0 of the System Impact Study Agreement (SISA) and tariff sheet 10-239, par 5.0 of the Facilities Study Agreement (FSA), a separate Statement of Work (SOW) has been issued to the Interconnection Customer showing the Interconnection Customer's share of the expense of the cluster System Impact Study as conveyed by the study participants to the Area EPS Operator.

- Each project above needs to have a signed System Impact Study Agreement and signed Facilities Study Agreement, with full payment delivered to the Area EPS Operator on or before the due date as communicated by the Area EPS Operator.

(Continued on Sheet No. 10-238)

CERTIFICATE OF SERVICE

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

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

xx electronic filing

DOCKET NO. E999/CI-16-521

Dated this 13th day of March 2025

/s/

_____

Joshua DePauw
Regulatory Administrator

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#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
						United States				
102	David	Moeller	dmoeller@allete.com	Minnesota Power			Electronic Service		No	16-521Official Service List PUC
103	Dalene	Monsebroten	dalene.monsebroten@nmpagency.com	Northern Municipal Power Agency		123 2nd St W Thief River Falls MN, 56701 United States	Electronic Service		No	16-521Official Service List PUC
104	Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP		33 South Sixth St Ste 4200 Minneapolis MN, 55402 United States	Electronic Service		No	16-521Official Service List PUC
105	Alex	Nelson	anelson@dakotaelectric.com	Dakota Electric Association		4300 220nd St Farmington MN, 55024 United States	Electronic Service		No	16-521Official Service List PUC
106	Ben	Nelson	benn@cmpasgroup.org	CMMPA		459 South Grove Street Blue Earth MN, 56013 United States	Electronic Service		No	16-521Official Service List PUC
107	David	Niles	david.niles@avantenergy.com	Minnesota Municipal Power Agency		220 South Sixth Street Suite 1300 Minneapolis MN, 55402 United States	Electronic Service		No	16-521Official Service List PUC
108	Michael	Noble	noble@fresh-energy.org	Fresh Energy		408 Saint Peter St Ste 350 Saint Paul MN, 55102 United States	Electronic Service		No	16-521Official Service List PUC
109	Rolf	Nordstrom	rnordstrom@gpisd.net	Great Plains Institute		2801 21ST AVE S STE 220 Minneapolis MN, 55407-1229 United States	Electronic Service		No	16-521Official Service List PUC
110	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	16-521Official Service List PUC
111	Logan	O'Grady	logrady@mnseia.org	Minnesota Solar Energy Industries Association		2288 University Ave W St. Paul MN, 55114 United States	Electronic Service		No	16-521Official Service List PUC
112	Timothy	O'Leary	toleary@llec.coop	Lyon-Lincoln Electric Cooperative, Inc		P.O. Box 639 Tyler MN, 56178-0639 United States	Electronic Service		No	16-521Official Service List PUC

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
113	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	16-521Official Service List PUC
114	Russell	Olson	rolson@hcpd.com	Heartland Consumers Power District		PO Box 248 Madison SD, 57042-0248 United States	Electronic Service		No	16-521Official Service List PUC
115	Wendi	Olson	wolson@otpco.com	Otter Tail Power Company		215 South Cascade Fergus Falls MN, 56537 United States	Electronic Service		No	16-521Official Service List PUC
116	Bethany	Owen	bowen@mnpower.com	Minnesota Power		30 West Superior Street Duluth MN, 55802 United States	Electronic Service		No	16-521Official Service List PUC
117	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	16-521Official Service List PUC
118	Dan	Patry	dpatry@sunedison.com	SunEdison		600 Clipper Drive Belmont CA, 94002 United States	Electronic Service		No	16-521Official Service List PUC
119	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	16-521Official Service List PUC
120	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	16-521Official Service List PUC
121	Susan	Peirce	susan.peirce@state.mn.us		Department of Commerce	85 Seventh Place East St. Paul MN, 55101 United States	Electronic Service		No	16-521Official Service List PUC
122	Wess	Pfaff	wes.pfaff@mrenergy.com			null null, null United States	Electronic Service		No	16-521Official Service List PUC
123	DONNA	PICKARD	dpickard@aladdinsolar.com	Genie Solar Support Services		1215 Lilac Lane Excelsior MN, 55331 United States	Electronic Service		No	16-521Official Service List PUC
124	Crystal	Pomerleau	crystal.r.pomerleau@xcelenergy.com	Xcel		null null, null United States	Electronic Service		No	16-521Official Service List PUC

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
125	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	16-521Official Service List PUC
126	Elizabeth	Psihos	elizabeth.psihos@idealenergies.com			null null, null United States	Electronic Service		No	16-521Official Service List PUC
127	Peter	Reese	preese@sundialsolarenergy.com	Sundial Energy, LLC		3363 Republic Ave Saint Louis Park MN, 55426 United States	Electronic Service		No	16-521Official Service List PUC
128	John C.	Reinhardt		Laura A. Reinhardt		3552 26th Ave S Minneapolis MN, 55406 United States	Paper Service		No	16-521Official Service List PUC
129	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	16-521Official Service List PUC
130	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	16-521Official Service List PUC
131	Kristi	Robinson	krobinson@star-energy.com	STAR Energy Services, LLC		1401 South Broadway Pelican Rapids MN, 56572 United States	Electronic Service		No	16-521Official Service List PUC
132	Daniel	Rogers	dan@nokomispartners.com			2639 Nicollet Ave Ste 200 Minneapolis MN, 55408 United States	Electronic Service		No	16-521Official Service List PUC
133	Michael	Ruiz	michael.ruiz@xcelenergy.com	Xcel Energy		null null, null United States	Electronic Service		No	16-521Official Service List PUC
134	Darla	Ruschen	d.ruschen@bcrea.coop	Brown County Rural Electrical Association		PO Box 529 24386 State Highway 4 Sleepy Eye MN, 56085 United States	Electronic Service		No	16-521Official Service List PUC
135	Robert K.	Sahr	bsahr@eastriver.coop	East River Electric Power Cooperative		P.O. Box 227 Madison SD, 57042	Electronic Service		No	16-521Official Service List PUC

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						United States				
136	Kenric	Scheevel	kjs@dairynet.com	Dairyland Power Cooperative		3200 East Ave S PO Box 817 La Crosse WI, 54602 United States	Electronic Service		No	16-521Official Service List PUC
137	Dean	Schiro	dean.e.schiro@xcelenergy.com	Xcel Energy		null null, null United States	Electronic Service		No	16-521Official Service List PUC
138	Kay	Schraeder	kschraeder@minnkota.com	Minnkota Power		5301 32nd Ave S Grand Forks ND, 58201 United States	Electronic Service		No	16-521Official Service List PUC
139	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	16-521Official Service List PUC
140	Ronald J.	Schwartau	rschwartau@noblesce.com	Nobles Electric Cooperative		22636 U.S. Hwy. 59 Worthington MN, 56187 United States	Electronic Service		No	16-521Official Service List PUC
141	Christine	Schwartz	regulatory.records@xcelenergy.com	Xcel Energy		414 Nicollet Mall FL 7 Minneapolis MN, 55401-1993 United States	Electronic Service		No	16-521Official Service List PUC
142	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	16-521Official Service List PUC
143	Dean	Sedgwick	sedgwick@itascapower.com	Itasca Power Company		PO Box 455 Spring Lake MN, 56680 United States	Electronic Service		No	16-521Official Service List PUC
144	Will	Seuffert	will.seuffert@state.mn.us		Public Utilities Commission	121 7th Pl E Ste 350 Saint Paul MN, 55101 United States	Electronic Service		Yes	16-521Official Service List PUC
145	Doug	Shoemaker	dougs@charter.net	Minnesota Renewable Energy		2928 5th Ave S Minneapolis MN, 55408 United States	Electronic Service		No	16-521Official Service List PUC
146	Felicia	Skaggs	fskaggs@meeker.coop	Meeker Cooperative Light & Power		1725 US Highway 12 E Suite 100 Litchfield MN, 55355 United States	Electronic Service		No	16-521Official Service List PUC
147	Trevor	Smith	trevor.smith@avantenergy.com	Avant Energy, Inc.		220 South Sixth Street	Electronic Service		No	16-521Official

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						Suite 1300 Minneapolis MN, 55402 United States				Service List PUC
148	Rafi	Sohail	rafi.sohail@centerpointenergy.com	CenterPoint Energy		800 LaSalle Avenue P.O. Box 59038 Minneapolis MN, 55459-0038 United States	Electronic Service		No	16-521Official Service List PUC
149	Beth	Soholt	bsoholt@cleangridalliance.org	Clean Grid Alliance		570 Asbury Street Suite 201 St. Paul MN, 55104 United States	Electronic Service		No	16-521Official Service List PUC
150	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	16-521Official Service List PUC
151	Braden	Solum	braden.solum@idealenergies.com	iDEAL Energies		5810 Nicollet Ave Minneapolis MN, 55419 United States	Electronic Service		No	16-521Official Service List PUC
152	Brandon	Stamp	brandon.j.stamp@xcelenergy.com	Xcel Energy		401 Nicollet Mall Minneapolis MN, 55401 United States	Electronic Service		No	16-521Official Service List PUC
153	Sky	Stanfield	stanfield@smwlaw.com	Shute, Mihaly & Weinberger		396 Hayes Street San Francisco CA, 94102 United States	Electronic Service		No	16-521Official Service List PUC
154	Kristin	Stastny	kstastny@taftlaw.com	Taft Stettinius & Hollister LLP		2200 IDS Center 80 South 8th Street Minneapolis MN, 55402 United States	Electronic Service		No	16-521Official Service List PUC
155	Eric	Swanson	eswanson@winthrop.com	Winthrop & Weinstine		225 S 6th St Ste 3500 Capella Tower Minneapolis MN, 55402-4629 United States	Electronic Service		No	16-521Official Service List PUC
156	Sherry	Swanson	sswanson@noblesce.com	Nobles Cooperative Electric		22636 US Highway 59 PO Box 788 Worthington MN, 56187 United States	Electronic Service		No	16-521Official Service List PUC

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157	Bryant	Tauer	btauer@whe.org	Wright-Hennepin		6800 Electric Dr Rockford MN, 55373 United States	Electronic Service		No	16-521Official Service List PUC
158	Emma Marshall	Torres	emarshall-torres@convergentep.com			null null, null United States	Electronic Service		No	16-521Official Service List PUC
159	Pat	Treseler	pat.jcplaw@comcast.net	Paulson Law Office LTD		4445 W 77th Street Suite 224 Edina MN, 55435 United States	Electronic Service		No	16-521Official Service List PUC
160	Jeff	Triplett	triplettj@powersystem.org	MREA		10710 Town Square Dr NW St 201 Minneapolis MN, 55449 United States	Electronic Service		No	16-521Official Service List PUC
161	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	16-521Official Service List PUC
162	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	16-521Official Service List PUC
163	Alan	Urban	alan.m.urban@xcelenergy.com	Xcel Energy		null null, null United States	Electronic Service		No	16-521Official Service List PUC
164	Ellen	Veazey	lveazey@solarunitedneighbors.org	Solar United Neighbors		1350 Connecticut Ave NW Ste 412 Washington DC, 20036 United States	Electronic Service		No	16-521Official Service List PUC
165	Sam	Villella	sdvillella@gmail.com			10534 Alamo Street NE Blaine MN, 55449 United States	Electronic Service		No	16-521Official Service List PUC
166	Wendy	Vorasane	wendy.vorasane@idealenergies.com			null null, null United States	Electronic Service		No	16-521Official Service List PUC
167	Robert	Walsh	bwalsh@mnvalleyrec.com	Minnesota Valley Coop Light and Power		PO Box 248 501 S 1st St Montevideo MN, 56265 United States	Electronic Service		No	16-521Official Service List PUC
168	Roger	Warehime	roger.warehime@owatonnautilities.com	Owatonna Municipal Public Utilities - Gas		208 S Walnut Ave PO BOX 800 Owatonna MN, 55060	Electronic Service		No	16-521Official Service List PUC

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
						United States				
169	Samantha	Weaver	samantha@communitysolaraccess.org	Coalition for Community Solar Access		1380 Monroe St. Washington DC DC, 20010 United States	Electronic Service		No	16-521Official Service List PUC
170	Elizabeth	Wefel	eawefel@flaherty-hood.com	Missouri River Energy Services		525 Park St Ste 470 Saint Paul MN, 55103 United States	Electronic Service		No	16-521Official Service List PUC
171	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	16-521Official Service List PUC
172	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	16-521Official Service List PUC
173	Robyn	Woeste	robynwoeste@alliantenergy.com	Interstate Power and Light Company		200 First St SE Cedar Rapids IA, 52401 United States	Electronic Service		No	16-521Official Service List PUC
174	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	16-521Official Service List PUC
175	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	16-521Official Service List PUC