Staff Briefing Papers

Meeting Date	**March 14, 2024**	**Agenda Item 3****
Company	All Electric Utilities	
Docket No.	E-999/CI-16-521 **In the Matter of Updating the Generic Standards for the Interconnection and Operation of Distributed Generation Facilities Established Under Minn. Stat. § 216B.1611**	
Issues	What changes to the Minnesota Distributed Energy Resources Interconnection Process (MN DIP) should the Commission make to achieve the purpose of Minnesota Law 2023, Ch. 60, Art. 12, Sec. 75 (HF 2310)?	

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✓**Relevant Documents**	**Date**
PUC – Notice of Comment	September 1, 2023
<u>Proposals</u>	
Xcel Energy	November 1, 2023
Otter Tail Power	November 1, 2023
Dakota Energy Association	November 1, 2023
Minnesota Rural Electric Association	November 1, 2023
MnSEIA – Including Exhibits A and B	November 1, 2023
<u>Initial Comments</u>	
Xcel Energy	January 19, 2024
Department of Commerce	January 19, 2024

✓**Relevant Documents**	**Date**
Dakota Electric Association	January 19, 2024
MnSEIA – Including Exhibits A and B	January 19, 2024
US Solar	January 19, 2024
Nokomis Energy	January 19, 2024
All Energy Solar – Including Addendums 1 and 2	January 22, 2024
Coalition for Community Solar Access	January 22, 2024
<u>Reply Comments</u>	
Xcel Energy	February 2, 2024
Dakota Electric Association	February 2, 2024
Solar United Neighborhoods; Institute for Local Self-Reliance; Cooperative Energy Futures	February 2, 2024
All Energy Solar	February 2, 2024

I. Background

1. Legislative History

On May 24, 2023, the State of Minnesota passed House File 2310 (Law 2023, Ch. 60). Art. 12; Section 75 tasked the Commission with the following:

> Sec. 75. Public Utilities Commission Docket; Interconnection
>
> No later than September 1, 2023, the commission shall open a proceeding to establish interconnection procedures that allow customer-sited distributed generation projects up to 40 kilowatts alternating current in capacity to be processed according to schedules specified in the Minnesota Distributed Energy Resources Interconnection Process, giving such projects priority over larger projects that may enjoy superior positions in the processing queue.

On September 1, 2023, the Commission filed a Notice of Comment Period requesting interested participants to submit proposals on how to modify the Minnesota Distributed Energy Resources Interconnection Process (MN DIP) to meet the goals of HF 2310.[1] The Commission asked that the proposals address the following topics:

1. Interconnection procedures that allow customer-sited distributed generation projects up to 40 kilowatts alternating current in capacity to be processed according to schedules specified in the MNDIP, giving such projects priority over larger projects that may enjoy superior positions in the processing queue.
2. Whether the prioritization of these projects include areas where the distribution system is capacity constrained as well as in areas that are not similarly constrained.
3. Whether there are changes to the MN DIP that would be de minimis in nature regarding policy but would update the document to accurately reflect recent changes and references.
4. Are there other issues or concerns related to this matter?

On November 1, 2023, Xcel Energy (Xcel of the Company), Dakota Electric Association (Dakota or the Cooperative), Minnesota Rural Electric Association (MREA), and Minnesota Solar Energy Industries Association (MnSEIA) all filed proposals.

On November 1, 2023, Otter Tail Power (OTP) submitted comments.

On January 19, 2024, the Department of Commerce (the Department), Xcel, Dakota, MREA, MnSEIA, US Solar, Nokomis Energy (Nokomis) all filed initial comments.

On January 22, 2024, All Energy Solar (AES) and Coalition for Community Solar Access (CCSA)

[1] https://www.revisor.mn.gov/laws/2023/0/Session+Law/Chapter/60/

filed initial comments.

On February 2, 2024, Xcel, Dakota, All Energy Solar, and Solar United Neighborhoods (SUN)/Institute for Local Self Reliance (ILSR)/Cooperative Energy Futures (CEF) all filed reply comments.

This topic of treating customer-sited DG under 40 kW differently in the interconnection process has been heard by the Commission previously. The Commission's March 31, 2022 Order in Docket No. E999/CI-16-521 required Xcel Energy to expand its "parallel processing" to all fast-track projects in areas where there are no known capacity constraints. Effectively, this meant that instead of studying each application sequentially, one after another, Xcel would begin studying applications under 40 kW alongside, or in parallel with, larger projects ahead in the queue if the distribution system was not capacity constrained in that area.[2]

2. Technical Planning Standard History

A central piece to Xcel's proposal in this docket, discussed further below, includes the Technical Planning Standard (TPS) practice that Xcel has implemented over their entire distribution system.[3] Staff finds it helpful to provide background on the TPS before discussing specific proposals that address the legislative criteria described above.

The TPS entails a methodology to determine the maximum allowed amount of distributed energy resource (DER) generation on a distribution feeder or substation transformer. Staff notes that the TPS is used for planning purposes as an approximation of the maximum DER limit on portions of Xcel's distribution system based on a variety of engineering assumptions and calculations. The TPS had a few iterations before Xcel implemented it in its current form on March 1, 2022. On May 20, 2021, the Commission considered the proposed change at its agenda meeting and made no decision on the issue, and instead sought formal comment on the issues raised in the DGWG final report.

On July 16, 2021, the Commission filed a Notice of Comment in Docket No E-999/CI-16-521 on whether the TPS should be adopted. On August 25, 2021, Xcel announced it would implement the TPS in its current form, discussed in greater detail below, on October 1, 2021. This action was objected to by Fresh Energy, MnSEIA, and IREC. Xcel responded by saying that the TPS did not need Commission approval, but stayed implementation until the Commission had a chance to review the practice.

The Commission heard the item on January 20, 2022, and issued a Commission Order on March 31, 2022. The Commission Order stated:

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[2] Order Point 2

[3] Staff notes that originally, the Technical Planning Standard (TPS) was named the Technical Planning Limit (TPL) when it was first introduced. Xcel changed the name to TPS when they implemented it. The TPS and TPL are to be used interchangeably but Staff primarily used TPS to avoid confusion.

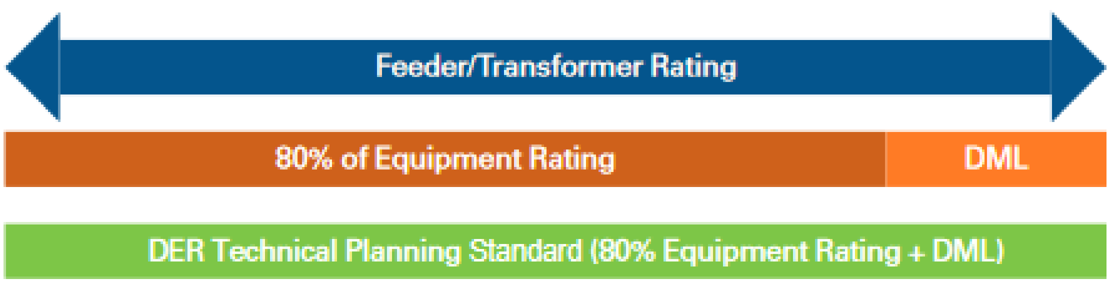
> While the commenters opposing Xcel Energy's change to the technical planning limit have valid concerns, the limitation may have a foundation in sound engineering practice. The Commission, however, cannot make that determination at this time based on the limited information in the record. Instead of making a change now, the Commission will require Xcel Energy to provide information which will help all parties in the future.

Xcel implemented the TPS on March 1, 2022, and has not been altered since that date. On September 12, 2023 the Minnesota Solar Advocates filed a complaint against Xcel's TPS in Dockets Nos E-999/CI-16-521 and E-002/C-23-424. On December 14, 2023, the Commission heard the item and determined that the TPS was an engineering judgement and Xcel was allowed to proceed with the standard as currently implemented. The Commission Order was filed on February 27, 2024.

3. Technical Planning Standard Mechanics

The TPS in its current form acts as a generation capacity limit, or buffer, on the distribution system by capping the generation allowed on the system to 80% of the equipment's thermal rating plus the Daytime Minimum Load (DML). This was a change from Xcel's previous historical practice of using 100% of the equipment's thermal rating plus the DML. Daytime Minimum Load is defined as the minimum amount of load or power delivered to customers on a feeder during a certain period of time. This typically occurs during the spring and fall when heating and cooling loads are lower. Figure 1 illustrates the relationship between the TPS and the distribution feeder/transformer rating.

Figure 1: Xcel's DER Technical Planning Standard Methodology



TPS Equation: $DER\ Technical\ Planning\ Standard = (E_r * 80\%) + L_{DML}$

Where:
DER Technical Planning Standard = Maximum Allowed DER on Feeder or Substation Transformer
E_r = Limiting Thermal Equipment Rating
L_{DML} = Daytime Minimum Load

Xcel specifies that the thermal equipment rating applies to both the feeder level and the substation level, meaning that while feeders on their own might not hit their respective equipment rating, collectively, they could add up to meet the substation's equipment rating.

The total generation capacity limit of the TPS can be altered through either the equipment rating on the distribution system or changes to the DML, as shown in Figure 1 above. The equipment rating can be changed via distribution system upgrades that increase the thermal capacity. These upgrades are the typical solution that Xcel provides to DER developers in the interconnection process if capacity levels are reached. The DML can be increased via adding load, typically through electrification (households switching from gas to electric, adding an electric vehicle, etc.) or an increase in customer base. The DML can also be decreased through efficiency improvements, the addition of DERs, and a decrease in the customer base.

Staff note that Xcel's proposal, as described in the Discussion section below, will alter the TPS formula to be 100% of Limiting Equipment Rating, but will not include the DML. In addition, 50% of the Limiting Equipment Rating will be reserved for small DER systems under 40kW.

4. Related Prior Order

Parallel Processing in Unconstrained Areas

This topic of treating customer-sited DG under 40 kW differently in the interconnection process has been heard by the Commission previously. In the March 31, 2022, Commission Order (Docket No. E999/CI-16-521), the Commission ordered Xcel Energy to expand its "parallel processing" to all fast-track projects in areas where there are no known capacity constraints. Effectively, this meant that instead of studying each application sequentially, one after another, Xcel would begin studying applications under 40 kW alongside, or in parallel with, larger projects ahead in the queue if the distribution system was not capacity constrained in that area.

II. Discussion

The PUC received proposals from Xcel, Dakota, MREA, and MnSEIA. The proposals can be broadly categorized into 1) Two Administrative Queues, 2) Two Administrative Queues with capacity reservation for Small DER projects (40kW and under), 3) a new Screen Review for Non-Exporting Projects, 4) New Size-to-Load Specification, and 5) Compensation to Larger DER (over 40kW). The proposals are summarized below in Table 1.

Table 1: Party Proposals

Party	Proposals	Description	Further Details
Xcel	Two Administrative Queues	A "Priority Queue" for "customer-sited" projects under 40kW. A "General Queue" for projects larger in size.	Customer-cited projects follow 120% rule. Priority Queue projects have priority unless General Queue application has begun an System Impact Study (SIS) or been issued an Interconnection Agreement (IA)
	TPS – Small DER Reservation	New TPS Formula: 100 Equipment Rating, no DML. 50% of capacity reserved for under 40kW projects	MN DIP to allow reservation of DER capacity for Priority Queue. Specific reservations for Area EPS in own Tariff.
Dakota	Two Administrative Queues	One Queue for under 40kW projects, another for over 40kW projects.	Larger systems studied with assumption that all 40kW projects planned over the next 6-12 months in queue are interconnected.
MREA	Two Administrative Queues	One Queue for under 40kW projects, another for over 40kW projects.	Would not apply to capacity constrained areas.
MnSEIA	New Screening Review for Non-Exporting Facilities	A screen to allow easier and quicker processing for non-exporting facilities	If a project fails the new screen, then further use of advanced inverter use in studying.
	New Size-to-Load Specifications	Increase the Size-to-Load to 200% of average load, up from 120%.	N/A
	Compensation to large DER	Compensation to large DER for time lost to exporting system having priority in queue	Funding source could be from application fees or state.

A. Xcel's Proposal – Two Queues and Capacity Reservation

Xcel anticipates a "significant increase in DER over the next several years" which the Company states may exacerbate issues that stem from capacity constraints on the distribution system caused, at least in part, by Community Solar Gardens (CSGs).[4] Xcel believes it to be "imperative to prioritize Small DER projects that have been pushed out due to the rapid expansion of larger DER projects."[5] To accomplish this, Xcel proposes a two-part plan that includes the creation of two administrative queues, one for projects 40kW AC and smaller, a "Priority Queue", and one for projects larger than 40kW AC, the "General Queue". The second aspect of this plan to proposes to modify their TPS to include what amounts to a 50% capacity reservation of their distribution system to be reserved specifically for customer-sited DER projects 40kW and under in size. In other words, 50% of the distribution system capacity would be reserved for the Priority Queue under this proposal.

<u>General and Priority Queue</u>

Xcel's proposal would modify the MN DIP to allow for two queues in the interconnection process: a "Priority Queue" for projects that are under 40kW AC, and a "General Queue" for projects that are larger than 40kW AC (**Decision Option 1**). Xcel states that a "Priority Queue" project would also be "customer-sited" which the Company defines as following the 120 percent rule, "whereby the total generation system annual energy production kilowatt hours alternating current is limited to 120 percent of the customer's on-site annual electric energy consumption."[6] Xcel's proposal also dictates that projects in the Priority Queue would have priority over applications in the General Queue unless a specific project in the General Queue has already begun a System Impact Study or been issued an Interconnection Agreement.

Xcel's specific MN DIP modifications are as follows for Sections 1.8.1, 1.8.3, and 1.8.5:

1.8.1

> Queue Position is assigned by the Area EPS Operator based on when the Interconnection Application is deemed complete as described in section 1.5.2, but Queue Position is also subject to the provisions of section 1.8.3 and 1.8.5. The Queue Position of each Interconnection Application will be used to determine the cost responsibility for the Upgrades necessary to accommodate the interconnection. The Queue Position also establishes conditional interconnection capacity for an Interconnection Customer, contingent upon all requirements of the MN DIP and MN Technical Requirements being met.

1.8.3

> The Area EPS Operator shall maintain two ~~a single,~~ administrative queues and may manage the queues by geographical region (i.e. feeder, substation, etc.). One

[4] Xcel Energy, Proposal, P. 4, November 1, 2024
[5] Xcel Energy, Proposal, P. 4, November 1, 2024
[6] Xcel Energy, Proposal, P. 8, November 1, 2024

queue is for "customer-sited" Interconnection. Applications up to 40 kWac (the "Priority Queue"), and the other queue is for all other Interconnection Applications (the "General Queue"). A "customer-sited" Interconnection Application is one that complies with the 120 percent rule whereby the total generation system annual energy production kilowatt hours alternating current is limited to 120 percent of the customer's on-site annual electric energy consumption. For existing customers, the application of the 120 percent rule must be based on standard 15-minute intervals, measured during the previous 12 calendar months. If a facility subject has either less than 12 calendar months of actual electric usage or has no demand metering available, then the means of estimating annual demand or usage for purposes of applying these limits will be based on looking at information for similarly situated customers. These~~is~~ administrative queues 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.

1.8.5

Applications in the Priority Queue have priority over applications in the General Queue unless a specific application in the General Queue has already begun a System Impact Study or been issued an Interconnection Agreement.

Capacity Reservation – TPS Formula Change

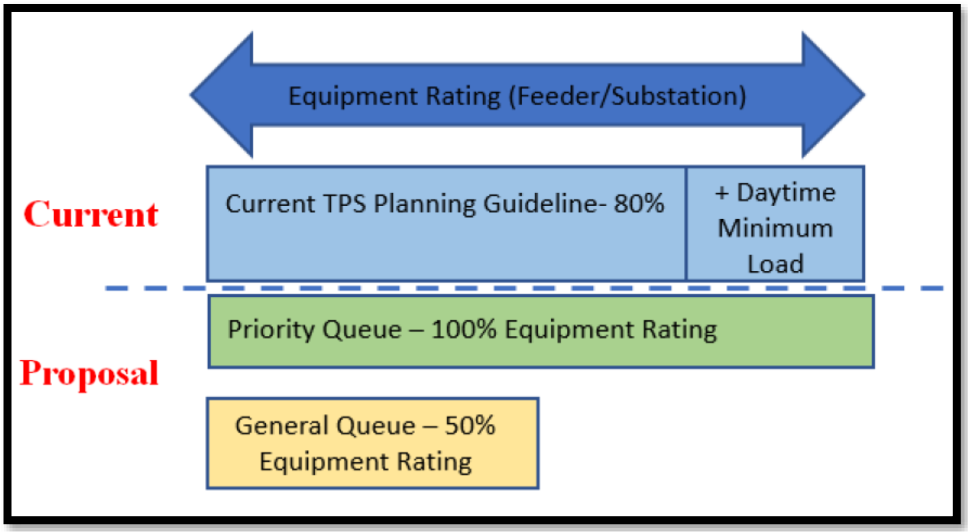
Xcel's second half of the proposal requests adding language to the MN DIP that would allow AREA EPS Operators the ability to reserve DER capacity (**Decision Option 7**):

1.8.6

The Area EPS Operator may reserve levels of available DER capacity in the Priority Queue that differs from the General Queue.

Xcel plans to use this new language to modify their TPS in a way that would reserve capacity solely for customer-cited, Small DER projects. Specifically, Xcel would change the Equipment Rating of the TPS to 100%, up from 80%. However, the proposal also removes the DML from the equation. Then, of the 100% Equipment Rating derived capacity, 50% would be accessible only to customer-cited projects under 40kW AC in size. Figure 2 details the change between the two.

Figure 2: Changes to the TPS



The Company stresses that high penetrations of DER, especially from larger projects like CSGs which currently amount to over 850MW of capacity, leads the distribution system to being capacity constrained and congested. A congested system leads to more complex engineering analyses, increased processing time, and longer queues. Xcel notes that even smaller DER systems require careful study when the distribution system is capacity constrained. Oftentimes, even residential projects will require costly upgrades in order to increase capacity for their contributing generation.

In determining the 50% capacity reservation, Xcel assumes that all residential customers might install PV in the future and that half of the rooftops will be suitable for PV systems. The Company states that there are currently 14,500 residential PV systems under 40kW on the grid out of a total of 1,200,000 total residential customers on the system. Xcel then cites growth rates from SEIA which project a national annual average growth rate of residential PV at 9%. Extrapolating from that projection, the Company determines that 50% of residential customers would have PV within 45 years (2049) at the national level. For Minnesota, Xcel states that a growth rate of 30% or 42%[7] per year will take 14 years or 10 years, respectively, to meet that assumed 50% uptake.[8]

Regarding how this process would work in capacity constrained areas, Xcel states that reserving capacity would allow Small DER projects to continue to interconnect even when the "General Queue" allotment (50% of total capacity) has been taken up, as long as the reserved 50% for Small DER still has capacity left.[9]

1. Response to Xcel Proposal

Two Administrative Queues

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[7] Xcel states this has been Minnesota's annual Small DER growth rate over the last 10 years.
[8] Xcel Energy, Proposal, P. 11, November 1, 2024
[9] Xcel Energy, Proposal, P. 12, November 1, 2024

The Department agrees that a two-queue system may meet the intent of the legislation. However, the Department is concerned that the solution is not required or necessary for all utilities, citing statements from Dakota and others that they are in the “free phase” of DER deployment and thus not experiencing the issues discussed in this proceeding.

Additionally, the Department is concerned that the two-queue solution may become obsolete as new technology becomes more widely available, may be more burdensome or inefficient to implement compared to the benefit it would provide, and may face challenges incorporating with Xcel’s IDP.[10]

Due to these concerns, the Department recommends implementing this two-queue proposal for an 18-24 month pilot duration and limit the application of the pilot to Xcel only (**Decision Option 2 and 3**).[11] Additionally, the pilot should not be implemented until Xcel’s and other utilities’ IDPs has been reviewed. All Energy Solar (AES) states that having two administrative queues will be challenging to manage in the long term and thus agree with the Department that this should be limited to Xcel and be a pilot project rather than permanent.[12]

Regarding the two administrative queues part of the proposal, MnSEIA agrees that it should be considered but believes that it may be best to apply the two queue proposal specifically to feeders that are congested (**Decision Option 1C or 2C**).[13] Applying it in this way would alleviate the burden of making any changes to the utilities that do not have a congestion issue (essentially to apply to Xcel only). Additionally, MnSEIA requests that this proposal not be made permanent until it can be demonstrated to meet the Legislature’s goals without creating additional problems. MnSEIA also suggest that distribution upgrades required under the second queue on congested feeders be funded by the DER Upgrade Program the Department is considering in Docket 23-458.[14]

Dakota believes that Xcel’s two administrative queue proposal is similar to their own proposal and believe it to be workable for their members. However, Dakota notes that it may be administratively burdensome in instances of lower penetration as it will “represent additional work and documentation that will not provide significant benefit to the utility or DER consumers.”[15]

Nokomis does not take a position on the two-queue proposal but questions how it would be different than what Xcel has already been ordered to do in prior proceedings, mainly to study Small DER projects in parallel in capacity unconstrained areas.[16]

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[10] Department of Commerce, Initial, P. 11, January 19, 2024
[11] Department of Commerce, Initial, P. 11, January 19, 2024
[12] All Energy Solar, Initial, P. 8, January 19, 2024; AES, Reply, P. 3, February 2, 2024
[13] MnSEIA, Initial, P. 6, January 19, 2024
[14] MnSEIA, Initial, P. 7, January 19, 2024
[15] Dakota Electric Association, P. 3, January 19, 2024
[16] Nokomis Energy, Initial, P.2, January 19, 2024

AES requests the Commission reject Xcel's definition of customer-sited to include the 120% size to load requirement. However, if the Commission approves Xcel's definition, AES recommends MnSEIA's proposal, discussed below, which would increase the threshold from 120 to 200% of customer consumption (**Decision Option 1D or 2A**).[17] AES says Xcel overestimates production of solar compared to real world outcomes and that expected historical usage should only increase with electrification and electrical vehicle adoptions. AES also requests the Commission structure "the MN DIP 'Priority Queue' to include storage and non-exporting systems."[18]

Dakota recognizes the discussion around the size-to-load threshold and suggests that it warrants additional discussion in the Distributed Generation Working Group.[19]

ILSR, SUN, and CEF request the Commission reject the two queue proposal as they disagree with the interpretation of how the law wishes utilities to prioritize small DER applications. However, if the Commission approves the two-queue proposal proceeds, they support the Department's recommendation of limiting it to Xcel and only as a pilot.[20]

ILSR, SUN, and CEF also agree with AES's position that a 120% size to load requirement is not necessary nor backed by statute, but if the Commission does find it necessary to establish a load requirement it should be increased to 200%.[21]

Additionally, the ILSR, SUN, and CEF requests the Commission direct Xcel as part of the potential pilot to "investigate greater use of cluster studies to facilitate multiple interconnection requests at one time, use of storage and other advanced technologies (like advanced inverters) to mitigate delays and system upgrades, and consider options from other states that may facilitate interconnection", identify changes necessary to the MN DIP, and model impacts of systems less than 40KW on feeders with different levels of capacity to determine effects on system operations (**Decision Option 2B**).[22]

Xcel Reply

As mentioned above, Nokomis questions how this policy would be different than the Commission's Order requiring Xcel study Small DER projects in parallel in capacity unconstrained areas. The Company clarifies that it would be different in that when studying the Small DER application, it will only assume the existing DER on the system as well as any current larger DER application being studied (if there is any) rather than assuming the existing DER plus the larger DER application and all of the other larger DER applications that joined the queue

17 All Energy Solar, Initial, P. 6, January 19, 2024
18 All Energy Solar, Initial, P. 10, January 19, 2024
19 Dakota Electric Association, P. 4, February 2, 2024
20 ILSR, SUN, CEF, Reply, P. 5-6, February 2, 2024
21 ILSR, SUN, CEF, Reply, P. 3, February 2, 2024
22 ILSR, SUN, CEF, Reply, P. 6, February 2, 2024

before the Small DER application.[23] Xcel provides an example to illustrate. First, assume three projects wanting to interconnect onto a portion of the system with 1MW of existing DER: 1) a Small DER project, 2) a 1MW CSG being studied, and 3) five more 1MW CSGs in the queue but not being studied. Under the current system, the Small DER project would assume there was 7MW worth of DER on the system, the existing 1MW, the 1MW of CSG being studied, and the 5MW of CSGs in the queue. Under Xcel's proposal, the Small DER project would only assume 2MW worth of DER, the existing 1MW and the CSG being studied. Xcel states the Small DER applications will be processed faster under the proposal but would still run the risk of a costly upgrade when interconnecting in a capacity constrained area.

In response to the Department requesting the two-queue proposal start as a 18-24 month pilot program, the Company states the timeframe appears arbitrary and that the MN DIP has built in processes to be adjusted in an ongoing fashion. Xcel claims that a pilot is not necessary as the Commission can accept the proposal and then later order something different in 18-24 months if circumstances warrant a change.[24]

Capacity Reservation, TPS Change

The Department finds Xcel's capacity reservation proposal "unsupported, discriminatory, and not in the public interest."[25] The Departments claims the modification to the TPS is "imprecise and unnecessary to achieve the directed legislative goal" and that the legislative directive was to give priority to small DER interconnection as it relates to speed, not volume, and therefore this version of the TPS is discriminatory toward larger DERs.[26] Additionally, the Department finds Xcel's assumptions on PV system growth, where half of all residential customers would install PV in the future, to be unsupported and unreasonable. ILSR, SUN, and CEF strongly agree with the Department's conclusions on Xcel's capacity reservation proposal.[27]

MnSEIA requests the capacity reservation modification be rejected as it is not in the public interest and is inconsistent with the legislative objective.[28] MnSEIA states that the current makeup of the TPS is already reducing the total potential DG on the distribution system by approximately 2.6 gigawatts and that this new formulation would reduce capacity by "exponentially more." Additionally, by limiting the capacity available to larger projects to only 50% of the equipment rating, all additional interconnection projects will be more expensive due to requiring distribution upgrades before they are needed. MnSEIA continues, theorizing that Minnesota's clean energy programs like Solar on Schools (SoS), Solar on Public Buildings (SoPB), and the new Distributed Solare Energy Standard (DSES) would not have much chance at success under this limitation.

[23] Xcel, Reply, P. 9-10, February 2, 2024
[24] Xcel, Reply, P. 11, February 2, 2024
[25] Department of Commerce, Initial, P. 13, January 19, 2024
[26] Department of Commerce, Initial, P. 13, January 19, 2024
[27] ILSR, SUN, CEF, Reply, P. 3, February 2, 2024
[28] MnSEIA, Initial, P. 9, January 19, 2024

MnSEIA also highlights that changing the TPS formulation as proposal appears much more like a policy decision rather than an engineering judgement. Lastly, MnSEIA states that this is too impactful of a change to make without first building a more robust record that details the impacts it would have on other legislative programs and projects.

Nokomis requests the Commission to reject Xcel's capacity reservation proposal, citing that the proposal is out of scope of the Notice.[29] Nokomis states that any considerations of capacity reservation should be taken up by the DGWG. Nokomis also claims that Xcel assumed 50% of residential uptake regarding residential PV is unsupported. Nokomis also points to legislation that created the DER Upgrade Program which specifically targets Small DER, stating the Legislature has already worked toward increasing capacity for Small DER.

US Solar also requests the Commission to reject Xcel's proposal and cites that this capacity reservation would impact other legislative projects like SoS and SoPB as well as the new CSG program.[30] US Solar states that Xcel does not attempt to quantify the harm this reservation would have on those programs and larger DERs generally, questions what the estimated cost will be for the grid upgrades caused by this new reservation, and how the proposal would impact Xcel's ability to meet the requirements in the new DSES.

AES also requests the proposal to be rejected as out of scope, as it is not a long term solution and would make interconnection costs unreasonable for the SoS, SoPB, and new CSG program.[31] AES also points out that the behind-the-meter (BTM) forecasting Xcel references in this docket is very different from the forecasting in the Company's IDP and requests the Commission to clarify these ambiguities. AES notes that Xcel's IDP states this reservation proposal would create $100,000,000 in existing upgrades immediately.[32]

AES states that if the Commission approves this proposal, Xcel should implement the reservation on a feeder-by-feeder level and "only in limited circumstances where the distribution utility can demonstrate through accurate forecasting and apparent need that such capacity reservation is required for that particular location on the grid" (**Decision Option 7A**).[33] AES also requests the Commission direct Xcel to initiate pilot programs to develop and advance innovative solutions that will increase capacity utilization, including the use of advanced inverter settings and storage pursuant to Minn. Stat. § 216B.2425, subd. 9, and Minn. Stat. § 216C.378 (**Decision Option 13**).

CCSA also does not support the capacity reservation proposal as it goes beyond what the legislature asked for and states that it would not fix the congestion problem, is arbitrary and overly restrictive, and would discriminate against larger projects like CSGs.[34] CCSA states that

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[29] Nokomis Energy, Initial, P.2, January 19, 2024
[30] US Solar, Initial, P. 2, January 19, 2024
[31] All Energy Solar, Initial, P. 5, January 19, 2024
[32] All Energy Solar, Initial, P. 4, January 19, 2024
[33] All Energy Solar, Initial, P. 7, January 19, 2024
[34] CCSA, Initial, P. 2, January 19, 2024

any "limits on feeder capacity should be site-specific and in response to a demonstrated need for reserve capacity – due to, for example, considerations related to customer density, type of area served, or customer demographics of the circuit" (**Decision Option 7A**).[35] CCSA also cites that they have not seen this practice done anywhere else in the nation aside from New Mexico and Maryland, noting that New Mexico invalidated the practice in 2023 and the Maryland PSC adopted revised regulations in January 2024 to have capacity limits placed on site-specific analyses and not on a broad rule of thumb.[36]

ILSR, SUN, and CEF find that Xcel's proposal "fails to consider that technology changes and adapts, along with customer usage and preferences" and skips other considerations like load growth through electrification (as removing the DML portion of the TPS makes the total capacity available to DER static rather than increasing with increased load), and improvements in inverter technologies.[37]

ILSR, SUN, and CEF also claim that there is not sufficient data to make these decisions. The group suggests that an underlying problem with Xcel's proposal is that the hosting capacity map is not updated often enough. Staff notes that the Commission ordered Xcel to update their Hosting Capacity Map monthly in the September 15, 2023 Commission Order.

Xcel Reply

In reply comments the Company states that they "fundamentally [disagree] with comments from CCSA, the Department, MnSEIA, US Solar, and Nokomis stating that the new law does not support reserving DER hosting capacity for customer-sited projects up to 40 kW" as "not reserving DER hosting capacity for these projects would prevent the Commission from fulfilling this legislative mandate."[38] Xcel cites that they have received many comments that expressed frustration in the lack of hosting capacity for their rooftop DER systems and their proposal works to address those frustrations by reserving that capacity.

Xcel warns that should no capacity be reserved for Small DER, capacity may be further consumed by larger DERs like CSGs, especially with the new CSG program that removes the contiguous county rule and expands the size of CSGs to 5MW, up from 1MW. The Company stresses that it would be important that the Commission "implement small solar capacity reservation as soon as possible to help prevent available hosting capacity being assigned to CSGs."[39] Xcel adds that a "separate queue alone, without a capacity reservation, is unlikely to achieve any longer-term benefits" and that without capacity reservation the distribution system will continue to "become oversaturated with large DER, and ultimately leaving no additional capacity for small DER to interconnect unless if significant and costly upgrades are

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[35] CCSA, Initial, P. 3, January 19, 2024
[36] CCSA, Initial, P. 3, January 19, 2024
[37] ILSR, SUN, CEF, Reply, P. 4, February 2, 2024
[38] Xcel, Reply, P. 5, February 2, 2024
[39] Xcel, Reply, P. 6, February 2, 2024

undertaken."[40]

Regarding the implications with public programs like Solar on Schools and Solar on Public Buildings, Xcel states that if the Commission wants to elevate priority for these types of programs to be consistent with the public interest, the Commission can dictate that these applications be placed in the priority queue and within the capacity reservation (**Decision Option 1B**).[41]

Regarding AES's request that Xcel use "innovative solutions" to increase capacity utilization, Xcel reiterates statements it made in the DER Upgrade Program docket that the Company is not against innovative solutions, but did not have time to properly evaluate solutions in that docket, and instead provided traditional solutions..[42] Xcel writes that the Company has addressed advanced interconnection as part its IDP proceeding and also has preliminary analysis of flexibility interconnection in the Distributed Energy Resources System Upgrade Program (Docket No. E002/M-23-458). Xcel suggests that the discussion of innovative technology solutions continue in the IDP process and will be explored more through the DGWG.

Regarding assumptions on their forecasts of DER uptake, Xcel cites the IDP which predicts significant growth in large, front-of-the-meter (FTM) solar due to the new CSG program as well as the DSES. However, the Company likewise forecasts BTM solar adoption to continue to grow between 50 and 70 MW per year from now until 2040.[43] Regarding forecasted costs, Xcel states that the capacity reservation policy would cause higher upgrade costs for FTM facilities, when compared to their current TPS practice, due to reduced available capacity combined with the growth in FTM solar due to the new CSG program and DSES. However, the Company states that upgrade costs are forecasted to be consistently lower after 2040 when compared to their current TPS because the capacity reservation will have prevented the need for more upgrades for Small DER when they are expected to accelerate in uptake.

Over the 30-year forecast, the Company states that the difference in total distribution upgrade costs between the two scenarios, the current TPS and the 50% capacity reservation, differ by less than 5%. The main difference is that the current TPS would increase cost allocations toward the BTM applications whereas the capacity reservation scenario would tilt the cost allocation toward the larger, FTM applications. Xcel notes that this does favor BTM facilities but believes it to be following the intent of the Legislature which the Company has interpreted to prefer Small DER projects over larger DER projects.[44] The Company cites the language of the law in this item as well as the language in the DER System Upgrade Program docket, E002/M-23-458, which requires that any created capacity from the upgrades identified in the docket should be reserved for Small DER.[45]

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[40] Xcel, Reply, P. 10, February 2, 2024
[41] Xcel, Reply, P. 6, February 2, 2024
[42] Xcel, Reply, P. 6, February 2, 2024
[43] Xcel, Reply, P. 8, February 2, 2024
[44] Xcel, Reply, P. 8-9, February 2, 2024
[45] Xcel, Reply, P. 7, February 2, 2024

B. Dakota and MREA Proposal – Two Administrative Queues

Dakota, and MREA both proposed having two administrative queues, one for projects that are under 40kW in size and one for projects greater than 40kW in size (**Decision Option 5**).[46]

Dakota's proposal would have the Cooperative process applications under 40kW as they come in for "all portions of their system which are not already limited."[47] Dakota would study larger than 40kW systems with an existing base of DER interconnections as well as the expected under-40kW system DER interconnection requests over the next six to 12 months. Dakota further clarifies that DER interconnection applications greater than 40kW will be studied sequentially – a project greater than 40kW can only proceed on that substation once the greater-than-40kW project that is being studied is cleared for interconnection or withdraws their request.

Dakota provides a hypothetical example where a feeder with 150kW of available capacity gets four DER applications of 10kW each and one larger DER application sized at 125kW.[48] Under the current status quo, if the 125kW application applied before the other four projects, it would take up all but 25kW of available capacity leaving the last two 10kW applications either reducing the size of the project, paying for a distribution upgrade, or withdrawing their application. Under the proposed system, the four 10kW projects would be studied in parallel with the larger project and be interconnected first, leaving 110kW of available capacity. Then, the larger 125kW project would have to choose to reduce the size of their system, pay for an upgrade, or withdraw their application.

Regarding whether the two queues would apply in capacity constrained areas, Dakota suggests that to do so it may be possible to extend the time periods for "dedicated review of small DER in capacity constrained areas if that is advantageous or possible for an internal staffing and resource perspective."[49] However, Dakota cautions that the Cooperative has a small number of internal staff and that further complications to the interconnection process may cause increased workloads and review times. Additionally, Dakota adds that this process would not help in the cases where there is no capacity available and that even small DER applications would still be faced with potentially costly distribution upgrade barriers.

Dakota, MREA, and Otter Tail Power note that the issues that prompted the requested proposals (queue congestions, long wait times, high costs to interconnect) are not issues that they are currently experiencing (Dakota described it as still being in the "free phrase" of DER development).[50] Dakota reiterates that this two-queue solution will meet the legislative goals

[46] MREA, Proposal, P. 2, November 1, 2023; Dakota Electric Association, Proposal, P. 5, November 1, 2023
[47] Dakota Electric Association, Proposal, P. 5, November 1, 2023
[48] Dakota Electric Association, Proposal, P. 5-6, November 1, 2023
[49] Dakota Electric Association, Proposal, P. 7, November 1, 2023
[50] MREA, Proposal, P. 1, November 1, 2023; Otter Tail Power, Proposal, P. 1, November 1, 2023; Dakota Electric Association, Proposal, P. 4, November 1, 2023

but views it as a short-term solution and that other areas need to be address to resolve the issues in the long term. Additionally, Dakota details that some of the drawbacks to this proposal include shifting upgrade costs to over 40kW facilities (which Dakota states likely does not go against legislative goals), does not resolve the full capacity constrained areas, and that the administrative management of multiple queues could become difficult, especially for smaller utilities.[51]

1. Response to Dakota's Proposal

The Department's response to two interconnection queues is the same for Dakota's and Xcel's proposals. In summary the Department recommends implementing this two-queue proposal for a 18-24 month pilot duration and limit to Xcel in its applicability.[52] Additionally, the pilot should not be implemented until Xcel's and other utilities' IDPs has been reviewed.

Xcel believes that Dakota's proposal is similar to their own but different in a few key ways. First, Xcel writes that their capacity reservation proposal is crucial and more precise and provides "clear direction to projects larger than 40 kW without the risk of delaying these projects."[53] Further, Xcel states that while Dakota's proposal ensures that Small DER projects planned in the 6-12 month timeframe will be interconnected, their proposal works to ensure that all Small DER projects are able to interconnect.

In response to comments, Dakota would also support the Commission taking no action on two administrative queues for the Cooperative.

C. MnSEIA Proposal – New Screen, Size-to-Load, and Compensation

MnSEIA begins by stating that their interpretation of the purpose of the Minnesota Law is to interconnect small projects as quickly as possible and not to simply have those projects bypass the larger projects. Additionally, MnSEIA believes that if there is a "fast lane" for small projects that projects that are "sized-to-load" should be treated differently than projects that are not sized-to-load (i.e., net-metered facilities) because the impact each project has on the grid is different. Projects that are primarily used to offset load would have minimal impacts on the grid compared to net-metered facilities which will send more generation onto the distribution system.[54]

MnSEIA suggests that this impact on larger projects should be compensated, offering that a fee could be put in place for net-metered facilities (**Decision Option 11C**).[55] In their initial comments, MnSEIA adds that money could be allocated under the Distributed Energy

[51] Dakota Electric Association, Proposal, P. 6, November 1, 2023

[52] Department of Commerce, Initial, P. 11, January 19, 2024

[53] Xcel, Initial, P. 3, January 25, 2024

[54] MnSEIA, Proposal, P. 4, November 1, 2024

[55] MnSEIA, Proposal, P. 5, November 1, 2024

Resources System Upgrade Program, and clarifies that this is not meant to pay for required distribution upgrades.[56]

Regarding additional screens, MnSEIA points to Massachusetts, New Mexico, and Illinois as examples Minnesota could emulate. MnSEIA writes that in Massachusetts 15kW-and-under systems that use certified inverters are only screened to confirm that the aggregate DER does not exceed 15% or more of the annual peak load and are approved for interconnection upon completion. In New Mexico, systems under 10kW get screened for aggregate generating capacity of under 65% of the Substation Rating and compatibility with the transformer rating. Illinois permits up to 100% of DML on the basis of aggregate export capacity.[57]

In initial comments, MnSEIA also recommends increasing the projects' "sized to load" threshold to 200% of load, up from 120%.[58] MnSEIA cites that 120% will likely not be sufficient to meet their members' own load, especially as electrification increases.

In summary, MnSEIA requests the MN DIP be changed first to allow for the following (**Decision Options 11A, 11B, 11C, 1D or 2A**):[59]

1. Creation of a different screening review process for non-exporting facilities.
2. Should a new screen not be created, MnSEIA requests that Small DER projects be able to obtain "interconnection approval through the usage of advanced inverter settings for curtailment to mitigate export in excess of grid capacity."
3. For small projects that are not sized to load, the impact of the smaller project or projects on the larger projects in the queue should be determined so that those costs can be offset or otherwise compensated so that the larger projects are not prejudiced.
4. Increase the definition of projects "sized to load" to 200% of customer load.

1. Response to MnSEIA's Proposals

New Screen and Using Advanced Inverters

Regarding MnSEIA proposals about an additional screen and or use of advanced inverters for interconnection, the Department believes they "bear further exploration, and that promise supports limiting the priority queue proposal to a pilot."[60]

Xcel is unclear on what a new screen as suggested by MnSEIA would look like, what changes would need to be made to implement, and how it would differ from the Simplified track that is already in the MN DIP.

[56] MnSEIA, Initial, P. 8, January 19, 2024
[57] MnSEIA, Proposal, P. 5-6, November 1, 2024
[58] MnSEIA, Initial, P. 7, January 19, 2024
[59] MnSEIA, Proposal, P. 5-6, November 1, 2024
[60] Department of Commerce, Initial, P. 10, January 19, 2024

Regarding the use of advanced inverter settings, the Company notes that they recently began studying these functions in DER interconnection impact studies and that they were required to use them as of January 1, 2024. However, they note that advanced inverters still require technical review or study to verify that voltage impacts are resolved. Xcel does not support including any technical mitigation requirements to the MN DIP to this end as the Company believes the scope of the MN DIP should remain procedural. However, Xcel would support the creation of a new expedited path to interconnection for small, non-exporting, behind the meter interconnection applications (**Decision Option 14**).[61] Xcel states that this rule change would "require the Company to change its engineering practice to remove load from the thermal loading calculation and calculate by aggregate generation export only."[62] AES also encourages amending the MN DIP to equitably give priority to consumers limiting their export with battery storage by including a tier for non-exporting interconnection in the priority queue.[63]

On MnSEIA's references to other states' practices, Xcel claims that the details about the New Mexico "interconnection standards and processes appear to be misunderstood, misrepresented, outdated, and not relevant to any issue here."[64] Additionally, Xcel continues, the attachment MnSEIA included with their proposal is a state document, not an Xcel document, from 2008 that is no longer relevant as the rules have since been altered to reference the TIIR rather than the attached manual. In reply comments, Xcel examined the Massachusetts example provided by MnSEIA and claims that MnSEIA did not accurately convey how Massachusetts conducts their interconnection process and states that in reality the MA process is very similar to the Simplified Track that Minnesota already has.[65]

AES supports the Commission's consideration of MnSEIA's proposal to utilize advanced interconnection solutions already working in other states with 100% clean energy deployment goals and requests the Commission update "the MN DIP in a manner consistent with advanced interconnection policies being utilized in other states with similar climate goals."[66]

In reply comments, AES supports adding amendments to the MN DIP that "define the export capacity of a system and differentiate export capacity from nameplate capacity." AES also supports additional screens that "define where export capacity should be used and incorporate an inadvertent export screen as part of initial review." However, AES believes that these discussions should first flow through the DGWG and be reviewed before recommendations be brought to the DGWG (**Decision Option 14**).[67]

<u>Compensation to Larger DERs</u>

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[61] Xcel, Initial, P. 7, January 25, 2024
[62] Xcel, Initial, P. 7, January 25, 2024
[63] All Energy Solar, Initial, P. 7, January 19, 2024
[64] Xcel, Initial, P. 8, January 25, 2024
[65] Xcel, Reply, P. 11-12, February 2, 2024
[66] All Energy Solar, Initial, P. 2, January 19, 2024
[67] All Energy Solar, Reply, P. 3, February 2, 2024

The Department finds MnSEIA's compensation proposal to larger DERs to be contrary to legislative intent and not in the public interest, stating that "nothing in statute directs, or even hints, that small DERs must pay for this prioritization."[68] The Department reiterates that smaller systems would likely be less able to absorb distribution system upgrade costs and it would likewise be unreasonable to have them absorb a "toll" for jumping the queue.

Regarding compensation to larger DER projects, Xcel cites that they disagree with their interpretation of the 2023 legislation and the Legislature did intend to "bypass the larger projects" and does not believe that larger DER were meant to be compensated. The Company notes that MnSEIA did not provide any specifics regarding who would administer the fund, who would be required to pay, and how those fees would be collected.[69]

<u>New Sized-to-Load Threshold</u>

The Company notes that MnSEIA is suggesting a redefinition of net metering to increase the 120 percent of energy consumption to 200 percent. Xcel states that this could result in significantly larger DER installations relative to load and that changing the definition is out of scope of this docket and is a subject much broader than the MN DIP. Xcel suggests that this proposal does not prioritize small DER installations and therefore the Company does not support it.

In reply comments, Xcel also adds that 120 percent is the Minnesota standard and cites several statutes that reference the 120 percent requirement, including the net metering statute, CSG subscription size caps, the public SoS and SoPB programs, and Solar*Rewards compliance.[70] Xcel claims that increasing to 200 percent would also require more distribution upgrades, which would delay those interconnection projects, and that the secondary system equipment was designed for customer load, not potential generation exports. Regarding accounting for electrification, Xcel first provides a mock up, shown in Figure 3, of what up-to-200% generation would look like in a household that has an EV and that the 120% limit is still reasonable under this scenario.[71]

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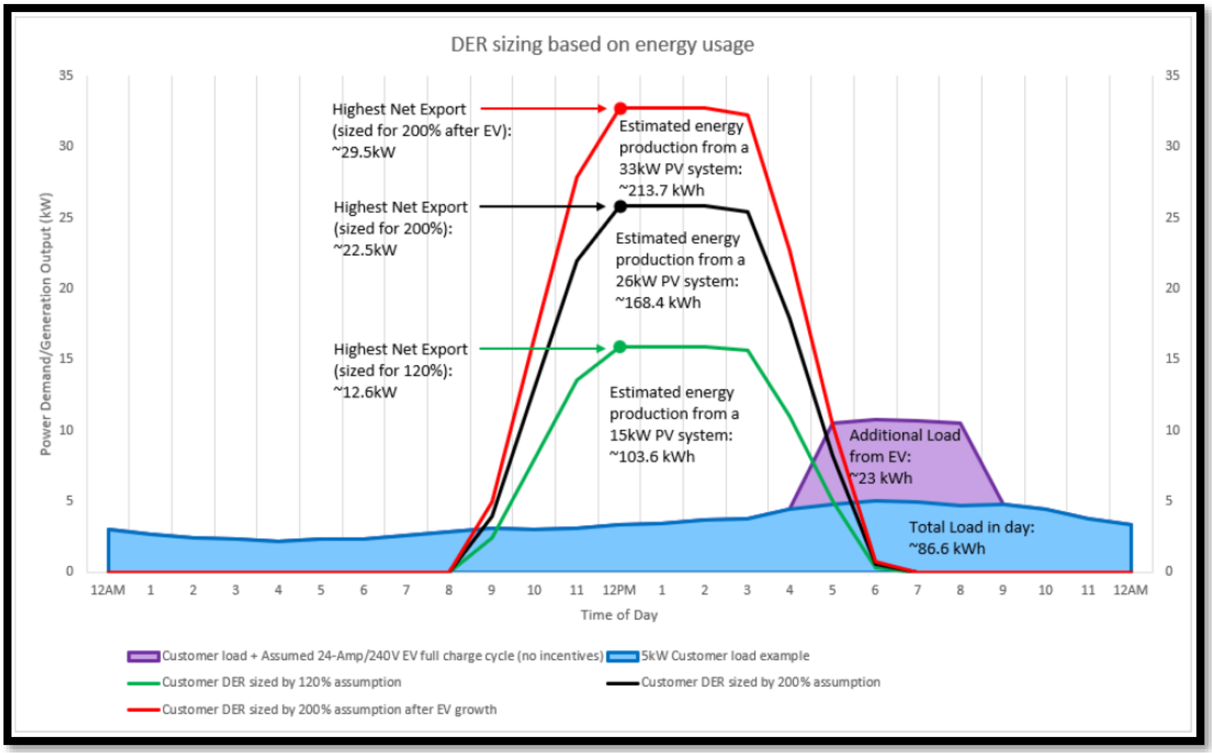
[68] Department of Commerce, Initial, P. 13, January 19, 2024
[69] Xcel, Initial, P. 5-6, January 25, 2024
[70] Minn. Stat. § 216B.164, Subd. 4c; Minn. Stat. § 216B.1641, Subd. 1 (b); Minn. Stat. § 216C.375, Subd. 5, Minn. Stat. § 216C.377, Subd. 5; Tariff sheets 9-16, 9-36, and 9-49.03
[71] Xcel, Reply, P. 14-15, February 2, 2024

Figure 3



Additionally, Xcel says that there are procedures in the MN DIP where customers can add additional DER to their system if their annual consumption is increased due to electrification or consumption use changes.[72]

Dakota agrees with MnSEIA in that net-metered facilities can place additional stresses on distribution and can unreasonably shift costs to other consumers, but they disagree with MnSEIA's definition of size to load stating that it "does not align with our understanding, or application, of sized to load from an operational or engineering perspective."[73] Dakota believes this discussion may be more appropriate to have in the DGWG.

AES supports moving the sized to load threshold to 200% of energy consumption if the Commission requires a sized to load threshold but ultimately does not believe the requirement to be necessary.[74] ILSR, SUN, and CEF share similar sentiments.[75]

D. Miscellaneous

<u>Energy Storage</u>

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72 Xcel, Reply, P. 15, February 2, 2024
73 Dakota Electric Association, P. 4, January 19, 2024
74 All Energy Solar, Initial, P. 6, January 19, 2024
75 ILSR, SUN, CEF, Reply, P. 3, February 2, 2024

Dakota also brought up the idea of how energy storage could relate to the Legislature's intent regarding the interconnection of DER under 40kW in capacity. Currently, the MN DIP treats DER capacity and energy storage on a combined basis – a 20kW solar facility and 25kW battery storage would be treated as 45kW of DER for interconnection studies.[76] Dakota states that this energy storage question was discussed at length in the DGWG but suggests the Commission may want to revisit the topic in light of meeting the intent of the Legislature.

AES also agrees that this energy storage question needs to be explored further and suggests amending the MN DIP to no longer treat energy storage and DER capacity on a combined basis, as well as to create a separate queue for non-exporting interconnections (**Decision Option 15**).[77] Xcel states that they are also interested in the topic of energy storage and would want to see it explored more in the DGWG. However, as it stands, Xcel states that there is currently no mechanism for a utility to confirm that a PV system would not export to the grid, even with a battery in place.[78]

Xcel would support adding non-exporting battery energy storage systems enter the priority queue over other applications but any changes to the MN DIP would first need to be vetted by the DGWG.[79] However, Xcel states that these projects might already be eligible to be in the priority queue if they meet the 120% rule and are less than 40kW in size.

<u>Cost Allocation</u>

Dakota offers setting the groundwork for what they view as a longer-term solution to addressing interconnection issues. The Cooperative sees the current practice of cost-causer pays, where the project that trips the need for an upgrade, regardless of the size of the project, is solely responsible for paying for that upgrade, as the reason for much of the conflict between larger and small DER facilities as well as the cost-barrier for small DER projects that get hit with a large and costly distribution system upgrade. While Dakota is not currently seeing these issues in their system, they foresee the potential for more issues as DER penetrations increase and would like to be proactive in its attempts at resolving them.

The Cooperative speculates that significant customer complaints in Minnesota involve higher interconnection upgrade costs for smaller DER facilities and may have spurred the Legislative directive at question in this item's Notice.[80] Dakota states that if the goal is to shield smaller DER installations "from high, and unexpected, interconnection upgrade costs, and avoid lengthy queue delays" then discussing longer-term solution may be beneficial.

Dakota offers a "make-ready" alternative to cost causer pays. Under this system Dakota suggests that they could make necessary distribution upgrades proactively, requiring no upfront

[76] Dakota Electric Association, Proposal, P. 9, November 1, 2023
[77] All Energy Solar, Initial, P. 8, January 19, 2024
[78] Xcel, Initial, P. 4, January 25, 2024; Xcel, Reply, P. 16, February 2, 2024
[79] Xcel, Initial, P. 4, January 25, 2024; Xcel, Reply, P. 16, February 2, 2024
[80] Dakota Electric Association, Proposal, P. 11, November 1, 2023

payment from Small DER facilities but would instead apply a monthly charge to each DER system to account for that upgrade.[81] The Cooperative notes that there is a risk to doing this in the case where a high-cost distribution upgrade could shift costs to future DER consumers and may also shift costs toward ratepayers who are unable to consider DER. However, Dakota states this approach would allow for smaller projects to proceed in almost all cases with minimal review and will remove the free rider dilemma that currently exists. Additionally, Dakota cites that a utility benefit to this approach is that it allows the utility to move away from the current piecemeal approach to distribution upgrades and instead focus on holistic system upgrades that provide greater benefit for the entire distribution system and optimize operational and cost efficiencies.[82]

Dakota provides additional details to their hypothetical cost allocation system such as having a "grandfathering in" period of existing DERs, applying a cost cap to "make ready" upgrades, thoughts on how to price the monthly fee and the length of the payment duration, as well as an illustrative example of the "make-ready" approach in their filing.[83] However, Dakota states that they are open to other ideas such as applying a one-time charge by system or per kW size of system, charging based on peak kW export of the unit to encourage load matching. Dakota emphasizes they are not requesting any changes to the MN DIP but thought it important to begin this conversation now while DER penetrations were low.

Xcel responded to Dakota citing that this is similar to their own Cost Sharing Program for projects under 40kW which can be found in Docket No. E002/M-18-714 and therefore does not take a position with the understanding that this proposal would only affect Dakota.[84]

MnSEIA shares similar sentiments that the cost-cause pays method is outdated and that costs should reflect the benefit to the ratepayer and future developers.[85]

AES supports the idea that the cost allocation question needs additional discussion and requests the Commission initiate an "investigation of Dakota Electric's 'Make Ready' proposals in a separate proceeding with the purpose of developing equitable allocation methodologies for DG customers to share the cost of updating the grid with other ratepayers who will also enjoy the benefits of increased grid capacity."[86] (Decision Option 17)

Somewhat related, CCSA supports a more proactive distribution system planning and investment.[87] CCSA states that regulators should "require distribution utilities to adopt planning frameworks whereby they ultimately propose proactive investments in the grid to enable future expected DER growth, promote electrification of customer load, and achieve

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[81] Dakota Electric Association, Proposal, P. 11, November 1, 2023
[82] Dakota Electric Association, Proposal, P. 12, November 1, 2023
[83] Dakota Electric Association, Proposal, P. 14-15, November 1, 2023
[84] Xcel, Initial, P. 4, January 25, 2024
[85] MnSEIA, Initial, P. 8, January 19, 2024
[86] All Energy Solar, Initial, P. 9, January 19, 2024
[87] CCSA, Initial, P. 3, January 19, 2024

other similar policy objectives."[88] CCSA proffers that this proactive approach would make state-wide goals easier to meet and would allow utilities to better identify least-cost solutions to grid needs. CCSA understands this topic is more in scope with IDP dockets but cites Massachusetts, New Jersey, and Maryland as states that are experiencing high DER penetrations but have been proactively upgrading the grid to accommodate those DERs. Xcel responds to CCSA in their reply comments noting that New Jersey and Massachusetts appear to subsidize or pay for distribution upgrades with ratepayer funds rather than the current cost-causer pays model Minnesota currently employs. Xcel sees potential benefit in having more flexibility to identify efficient upgrades but deems the topic out of scope of the current proceeding and recommends CCSA bring it up to the DGWG to be discussed more.[89]

E. MN DIP Edits for Clarity

The Commission asked if there were any updates or changes, de minimis in nature, that could be made to the MN DIP to more accurately reflect any recent changes and references.

Dakota offered a few changes. The first was to add a table relaying the time frames of each interconnection track to make it easier for applicants to follow and understand.

Section 1.5.2 – Creation of a Table[90]

Application Path	**Notification of Application Receipt**	**Notification of Application Completeness**	**Notification of Interconnection Approval**
Simplified	3 days from filing	10 days from filing	20 day from receipt of complete application
Fast Track	3 days from filing	10 days from filing	25 days from receipt of complete application
Study Process	3 days from filing	10 days from filing to initiate scheduling of scoping meeting	Per study process time-lines

Note: Days are Business Days

Section 3.4.5.2 – Clarification of 20 business day deadline[91]

> If the proposed interconnection requires construction of any facilities, the Area EPS Operator shall notify the Interconnection Customer of such requirement when it provides the supplemental review results and either: 1) provide a good faith cost estimate; or 2) require a facilities study pursuant to 4.4.1. Within five (5) Business Days, the Interconnection Customer shall inform the Area EPS Operator if the Interconnection Customer elects to proceed with the proposed interconnection. If the Interconnection Customer makes such an election, within

[88] CCSA, Initial, P. 3, January 19, 2024
[89] Xcel, Reply, P. 12, February 2, 2024
[90] Dakota Electric Association, Proposal, P. 8, November 1, 2023
[91] Dakota Electric Association, Proposal, P. 8, November 1, 2023

twenty (20) business days, the Area EPS Operator shall either provide: i) an Interconnection Agreement, along with a non-binding good faith cost estimate and construction schedule for such upgrades, ~~within twenty (20) Business Days after the Area EPS Operator receives such an election~~ or ii) a facilities study agreement pursuant to section 4.4.

Glossary of Terms: Clarification of technical requirements that have been updated since the creation of the TIIR.[92]

MN Technical Requirements – The term including all of the DER technical interconnection requirement documents for the state of Minnesota; including: the Minnesota DER Technical Interconnection and Interoperability Requirements (TIIR) and the Dakota Electric Technical Standards Manual (TSM). The terms Technical Requirements, Minnesota Interconnection Technical Requirements and Minnesota Technical Requirements are all considered referencing this set of technical requirements for the interconnection of DER. ~~1) Attachment 2 Distributed Generation Interconnection Requirements established in the Commission's September 28, 2004 Order in E-999/CI-01-1023) until superseded and upon Commission approval of updated Minnesota DER Technical Interconnection and Interoperability Requirements in E-999/CI-16-521 (anticipated in late 2019.)~~

Additionally, Dakota states the following updates can be made to the Attachments 2-4 and a typo error on page 1 one of the MN DIP.[93]

Attachment 2, Simplified Application Form: Replaced existing Simplified Interconnection Application with version approved by the DGWG in 2021. May 7, 2021 Notice Docket Nos. E999/CI-01-1023 and E999/CI-16-521.

Attachment 2, Exhibit B: This exhibit is removed. Energy Storage information is now contained in both updated applications.

Attachment 3: Replaced Interconnection Application with version approved by the DGWG in 2021. May 7, 2021 Notice Docket Nos. E999/CI-01-1023 and E999/CI-16- 521.

Attachment 4: Need to update the technical references to align with the updated TIIR document. This would include updating or possibly removing the footnote #14

Also page 1 – MN DTIIR to MN TIIR

[92] Dakota Electric Association, Proposal, P. 8, November 1, 2023
[93] Dakota Electric Association, Proposal, P. 9, November 1, 2023

The Department and Xcel support these de minimis changes to the MN DIP.[94]

III. Staff Analysis

This docket was borne from the Minnesota Legislature in House File 2310 (Law 2023, Ch. 60). Art. 12; Section 75 tasked the Commission with the following:

> Sec. 75. Public Utilities Commission Docket; Interconnection
>
> No later than September 1, 2023, the commission shall open a proceeding to establish interconnection procedures that allow customer-sited distributed generation projects up to 40 kilowatts alternating current in capacity to be processed according to schedules specified in the Minnesota Distributed Energy Resources Interconnection Process, giving such projects priority over larger projects that may enjoy superior positions in the processing queue.

The PUC issued a Notice of Comment Period to this end on September 1, 2023 and received proposals from Xcel Energy, MnSEIA, Dakota Energy Association, and Minnesota Rural Energy Association.

Staff will address each of the proposals issued by the parties but notes that several ideas brought forth in this record are out of scope for this particular proceeding. Staff believes many of the ideas are important and worth discussing but does not believe some of the ideas received sufficient record development given the potential impact they may have in the field and so will recommend that these topics be explored further before decisions are made.

Two Administrative Queues

Xcel, Dakota, and MREA offered very similar proposals to create two administrative queues, one for DERs 40kW AC and smaller and one for DERs larger than 40kW AC. The three proposals have only slight differences. Each of the proposals would prioritize Small DER applications getting studied over other larger projects in the queue that are not actively getting studied. The smaller projects would be studied in parallel with any larger project being studied and the available capacity assumptions when studied would include the existing DER on the system and any DER actively being studied.

This is different than the status quo in a few ways. First, these proposals differ from the status quo regarding the assumptions of available capacity. Where the proposals only assume existing DER and DER being actively studied, the status quo assumes the existing DER, the DER being actively studied, as well as DER projects that filed for interconnection before the smaller DER projects. This could be a large difference in available capacity assumptions depending on how

[94] Department of Commerce, Initial, P. 14, January 19, 2024; Xcel, Initial, P. 4, January 25, 2024

many projects are currently in the queue and how much available capacity is currently available on the respective feeders and substations. This ultimately means that more small DER applications may be interconnected under this proposal simply due to being processed more quickly before available capacity is diminished. However, Staff notes that this may, as a result, lead to fewer larger projects being interconnected without requiring distribution upgrades.

The second difference from the status quo is that the projects would be studied in parallel with larger projects rather than sequentially in the order of application filing date. Xcel currently does this in unconstrained areas after the March 31, 2022, Commission Order, but would begin doing so in capacity constrained areas as well should this proposal be accepted. However, Xcel notes that while these projects may be studied quicker in these constrained areas, the barriers of large upgrade costs would still be an issue, potentially making the projects economically unviable under current cost-cause pays policies.

Xcel provided MN DIP changes to create these two queues with edits to Sections 1.8.1, 1.8.3, and 1.8.5. Xcel's proposal would create a "Priority Queue" for projects that are customer-sited and meet the 120% rule. Dakota's proposal was higher level in nature. Dakota stated that they provided their proposal to meet the Minnesota Law but admit that they are currently in the "free phase" of development where this solution may actually not provide much benefit to its members and may instead be administratively burdensome to implement.

To Dakota's point, the Department believes Xcel should be the only Area EPS Operator that the law impacts as they are the only utility currently experiencing interconnection queue issues. The Department does not believe that the other utilities should be required to implement this proposal, that it should be limited to Xcel, and that edits to the MN DIP are not required to meet the goals of the legislation. The Department suggests Xcel's proposal be implemented via their tariff only and that it should be commenced as a 18-24 month pilot rather than a permanent solution with reasoning that the proposal may be obsolete with the integration of new technology and may actually add inefficiencies to the process. The Department suggests that only once the results are considered should the proposal become permanent, or an alternative proposal be considered. The Department did not suggest any reporting requirements be made if a pilot program is chosen.

Staff believes that the two-queue solution meets the intent of the Legislature as it would indeed give priority to Small DER over larger projects that are ahead in the queue. It is a similar mechanism to what Xcel has done with their parallel processing of Small DER in unconstrained areas (which was considered and approved in Docket No. E002/M-18-714), which has been a relative success in processing those applications more quickly as well as reducing the on-hold projects in those respective queues. Staff believes the two-queue solution may provide some modest improvements to processing times without unduly burdening other projects due to the relative size of most of these Small DERs. However, Staff agrees with Xcel and other parties that this does not resolve the larger issues at play such as areas of the distribution system being capacity constrained, and the cost-causer pays requirement smaller DERs face when trying to interconnect.

Staff is indifferent on whether this should be applied to the MN DIP or if it should be applied via Xcel's tariff only. Staff is in agreement with most parties that Xcel is the only utility that this proposal will immediately impact. However, DER forecasts suggest greater uptake generally in the next few decades and there could be advantages to having the language in place before other utilities see the need for it. The Commission may also choose to accept this proposal and integrate it into the MN DIP with the caveat that Area EPS Operators are required to implement it only when they experience a certain level of DER interconnection, similar to Area EPS being required to host a public interconnection queue only if they have received at least 40 completed Interconnection Applications a year (**Decision Option 1A**).[95] That way, the two-queue proposal will be applied to parties like Dakota, MP, and OTP once they are experiencing higher levels of DER interconnection. Staff would be interested in what the DER development threshold would need to reach for this program to be beneficial to Dakota and OTP in order to meet the legislative intent to prioritize Small DER in the queue process.

Regarding the Department's suggestion that this proposal be implemented as a pilot program due to it being obsolete because of various technology advancements, or that it may actually be detrimental in practice (**Decision Option 2**), Staff is unclear as to what technology advancements the Department had in mind that would meet the legislative intent to prioritize Small DER in the interconnection queue. Staff agrees with Xcel that the suggested duration is somewhat arbitrary when the Commission can choose to change its approach on the matter at a later time, but Staff believes having a deadline for a more thorough evaluation could be beneficial.

Regardless of whether this proposal is implemented through the MN DIP or Xcel tariff and whether it is "permanent" or a pilot, Staff believes some reporting should be required in order to track the progress. Staff suggests the following requirements, but the Commission may wish to hear from parties on other potential reporting requirements (**Decision Option 6**):

1. The number of Small DER applications interconnected under the new framework adopted to prioritize small DER.
2. Interconnection queue timelines for Small DER applications under the new framework and a comparison with timelines under the previous framework.
3. Interconnection queue timelines for large DER applications under the new framework and, if needed, a discussion of issues large DER applications may be facing.
4. Costs associated with implementing the new framework and a summary of the process implement under the new framework.

<u>Capacity Reservation</u>

Xcel's two-queue proposal was one part of a two-part proposal with the other part modifying their Technical Planning Standard (TPS) to essentially reserve 50% of the distribution system solely for Small DER (**Decision Option 7**). The Commission recently heard Xcel's current version of the TPS (80% of Equipment Rating + DML) on December 14, 2023, and issued an Order on February 27, 2024 determining that it was an engineering judgement on behalf of Xcel. In this

[95] MN DIP Section 1.8.4

proceeding, Xcel is proposing to modify the formula to 100% of the Equipment Rating excluding the DML and then, within that total amount, allocating 50% of that capacity to the Priority Queue. Xcel's reasoning for reserving capacity generally is due to their experience on several feeders and substations where larger DERs like CSGs have taken up all of the available capacity on the distribution system to the point where Small DER projects like rooftop solar cannot interconnect without first paying upgrades that can be as much as $1 million. The Company suggests that the new Non-Legacy CSG program, which increases the size of CSGs to 5MW from 1MW and eliminates the contiguous county rule (where subscribers can only subscribe to gardens in their county or directly adjacent) in addition to the DSES, will quickly lead to situations where even more areas of the grid are capacity constrained leading to more would-be Small DER customers unable to reasonably interconnect their projects.

Xcel expresses urgency to this end, stating that the longer capacity is not reserved, the more areas will become capacity constrained, locking out Small DER customers. Additionally, Xcel has interpreted the legislative intent to prefer Small DER customers to the point that every Small DER customer should have the ability to interconnect their system without facing significant distribution upgrade requirements. The Company bases this interpretation on the language used in this docket's Notice as well as in the DER Upgrade Docket which requires Xcel to reserve the capacity that is made free from the program to Small DER interconnection applications.

The Department, MnSEIA, Nokomis, AES, and CCSA determined Xcel capacity reservation proposal is out of scope of this Notice and beyond the legislative intent, and no other parties actively supported this proposal. Additionally, the same parties believe the proposal to be unsupported and discriminatory by providing undue preference to a specific class of customer, Small DER in this case.

Staff understands Xcel's rationale for including the concept of capacity reservation in their proposal and the reasons for implementing in a timely manner. Much of the consternation and complaints regarding interconnection stem from capacity constrained areas generally, but especially in how Small DER customers are unable to interconnect in these areas despite having relatively smaller impacts to the distribution grid. However, Staff believes that while the idea of a capacity reservation proposal is related to the topics raised in the notice, it is outside the scope of the current proceeding and requires additional record development if the Commission is inclined to move in that direction. Staff believes there may be merit to the Department's interpretation that the legislative directive was meant to give priority to Small DER as it relates to speed rather than volume, which is what the capacity reservation affect.

Staff notes that depending on the interpretation of the legislative intent, which appears to generally prioritize the interconnection of Small DER over larger DERs, at least as it pertains to queue wait times, the Commission could determine that a capacity reservation for Small DER, generally, is in the public interest. However, a reservation of this nature, 50% of Xcel's total distribution capacity, would be a great deviation from how the interconnection process currently works. Staff believes deviations of this magnitude require more scrutiny and record development to determine whether the changes are in the public interest. Staff is unconvinced, based on the available record, that the TPS should be modified in a way that give a 50% capacity reservation to Small DER.

However, Staff is persuaded by Xcel that this may be a pressing issue that perhaps deserves more expedited processing. The Commission could issue a Notice of Comment Period in an existing docket or establish a new proceeding that could directly ask if a capacity reservation is in the public interest and what level of reservation would be appropriate (**Decision Option 9**). Alternatively, the Commission could order the DGWG to address the issue and provide a report to the Commission (**Decision Option 10**). The former would create a record before the Commission on the issue directly, whereas the DGWG could offer a more informal discussion and analysis but at the expense of potentially taking longer to come to a resolution or decision by the Commission. Staff supports creating a new proceeding over sending the topic to the DGWG due to the relative time-urgency and the current bandwidth of the DGWG.

Size-to-Load Threshold

One of the requirements Xcel included for projects to be eligible for the "priority queue" was that they had to be a "customer-sited" interconnection application "that complies with the 120% rule whereby the total generation system annual energy production kilowatt hours alternating current is limited to 120% of the customer's on-site annual electric energy consumption."[96] MnSEIA, AES, and ILSR/SUN/CEF believe that the threshold should be increased to 200% of energy consumption if the requirement is necessary (**Decision Option 1D or 2A**). Their arguments suggest that projects that are sized-to-load have a smaller impact on the grid and that the 120% rule doesn't account for electrification and won't be sufficient to meet customers' own load.

Xcel's response is that the 120% rule is used in most other Minnesota statutes including net metering, the CSG program regarding subscription sizes, Solar*Rewards compliance, and the public SoS and SoPB programs, and that there are mechanisms in place for customers to apply for additional DER if they have increased their energy consumption through electrification or otherwise. Dakota also believes the 120% definition fits within their understanding of projects that are sized to load.

Staff is not convinced by the record available to deviate from the standardized 120% rule, especially when customers are able to apply for additional DER if their annual energy consumption increases. This topic could potentially be discussed further elsewhere but Staff believes there is insufficient record to make a decision at this point. However, Staff does agree that non-exporting systems do have a smaller impact on the distribution grid.

New Interconnection Screen and Advanced Inverters

MnSEIA's proposal also suggests creating a new screen in the interconnection process for non-exporting facilities (sized to load) and that if a new screen is not created, that advanced inverters be used to obtain interconnection approval by allowing curtailment to mitigate export in excess of grid capacity. MnSEIA then references Massachusetts, New Mexico, and Illinois that Minnesota could emulate to this end.

[96] Xcel Energy, Proposal, P. 8, November 1, 2024

MnSEIA does not provide additional details on what this screen would look like, and Xcel was unclear how it would differ from the Simplified Track already in place. However, Xcel is amenable to creating a new interconnection track for non-exporting DER but explained that it would require some changes to its engineering practices.

Staff does not believe the record is developed enough to make a decision on this topic. Staff notes that the discussion is similar to the discussion on storage which is addressed later in staff analysis where parties have recommended that the topic be explored further by the DGWG.

Staff notes that the use of advanced inverters is now required under the TIIR as of January 1, 2024.

<u>Compensation to Larger DERs in Queue</u>

MnSEIA's proposal requests the Commission develop some mechanism so that larger DER in the interconnection queue that are impacted by the prioritization of Small DER might be compensated or offset for the harm done to those customers (**Decision Option 11C**). MnSEIA suggest that the compensation could come from a cost sharing program similar to how Xcel's Cost Sharing Program is implemented for Small DERs where each application pays a defined fee. Alternatively, MnSEIA suggests the funds could be garnered under Minn. Stat. § 216C.378. Xcel believes this does not meet the legislative intent and the Department believes it to be contrary to the legislative intent and not in the public interest.

Staff agrees with Xcel and the Department that a compensation mechanism for the larger DERs in the queue is not in the public interest.

<u>Energy Storage and Non-Exporting Systems</u>

Several parties spoke to how the interconnection process currently treats energy storage and how that may be altered. For reference, DER generation and storage are considered on a combined basis in the MN DIP, meaning a 10kW PV system and 15kW battery pack would be 25kW worth of DER that would need to be studied for interconnection. AES and Dakota believe that more discussion may be warranted on whether these two systems should be considered in a combined way. Additionally, Xcel and AES suggest treating non-exporting systems in a different way and perhaps creating a new expedited interconnection track for that type of application. Staff believes these topics may deserve more exploration since the last time the DGWG addressed them given how the interconnection, distributed generation, and energy storage fields have evolved since then. The Commission may wish to have the DGWG address the topic again (**Decision Option 14 and 15**).

<u>Cost Allocation</u>

Cost allocation for necessary distribution upgrades is a nuanced topic where who pays for what, when, how, and on behalf of whom can have different answers depending on what the priorities of the decision makers are. Currently, Minnesota employs a cost-causer pays principle where the party or customer who necessitates the need for an upgrade in order to interconnect their project must pay the full price of that upgrade. The logic behind this principle is that those who benefit must also pay for that benefit and not be subsidized by groups that are not directly benefiting from that investment.

The Commission has heard criticisms of this model as it pertains to allocating costs for distribution system upgrades, namely that significant upgrade costs can fall on a single customer when additional projects or customers may benefit from the upgrade. This issue has been raised specifically regarding portions of Xcel's distribution system that no longer have free capacity for additional DER systems. To address this issue, the Commission has allowed Xcel to try out slightly different cost allocation methods to, among other goals, help alleviate the high upgrade cost obstacle. Xcel's Cost Sharing Program requires all Small DER customers pay into a cost sharing fund so that any particular customer that faces an upgrade requirement on the secondary system may have it paid for by the fund up to a cost of $15,000. Xcel is also currently implementing a Cluster Study pilot where several projects 1MW or greater applying for interconnection may be studied jointly rather than sequentially and would have any upgrade costs split among the different parties. Both of these methods are a variation of the cost-causer pays model but attempt to spread the costs amongst more of the beneficiaries rather than focus it onto an individual customer.

Staff references these issues simply to demonstrate that Minnesota grappling with these issues and has expended a fair amount of effort and resources on addressing some of these challenges that are borne from the caused cost-causer pays model. Parties in this docket and other dockets have suggested various alternatives to this model, all of which would require deliberate and well-reasoned decisions by the Commission if implemented. For example, Dakota provided a proposal where the Cooperative would proactively make distribution upgrades and then collect funds from DER customers after interconnection so that process is smooth regarding capacity availability. Others include a potential expansion of Xcel's Cost Sharing Program to projects greater than 40kW and continuing Xcel's Cluster Study pilot.

Comments in other dockets have suggested a further distancing from the cost-cause pays model and that distribution upgrades should be paid for by the ratepayers as a whole. Proponents of this model suggest expansion of renewable DER is paramount, should be done expeditiously, and that some cross-subsidization by ratepayers is worthwhile. Additionally, parties argue that this model would allow utilities to be more efficient with the distribution upgrades as they can holistically study the grid, make forecasts of expected DER penetration, and generally be more deliberate with their upgrades rather than the more reactive and piecemeal approach currently employed.

Staff believes cost allocation of distribution upgrades is a complex issue with several influencing factors, and that further discussion is needed regarding potential alternatives. The Commission has several options for discussing this issue, including the current docket, a new docket, the DGWG, and Xcel's Integrated Distribution Plan docket (Docket No. E002/M-23-452) where parties have also raised the issue of cost allocation across different types of scenarios. Staff recommends that Commission not make a decision on where to hear this issue, but instead rely on the Executive Secretary's existing authority to continue discussions as warranted in relevant processes.

De Minimus edits to the MN DIP

Dakota was the only party to offer edits to the MN DIP that would be de minimus in nature. Dakota offered a table that clarifies the time requirements for each of the interconnection tracks, some clarifying language in Section 3.4.5.2 regarding Area EPS Operator deadlines, updates to the Glossary of Terms sections, as well as some typos (**Decision Option 16**). The Department and Xcel support these edits. Staff also supports these edits and is appreciative to the Cooperative for suggesting these clarifications.

Extension of Rate Case Order

The Commission's July 17, 2023 Xcel Rate Case Order, par. 134 directed the DGWG to do the following:

> The Commission directs the Distributed Generation Working Group's (DGWG) Technical Subgroup (TSG) to convene to examine the possibility of unintentional islanding caused by interconnection of DERs. As part of the examination, the TSG will identify additional screens that utilities can perform to assess the risk of unintentional islanding, and determine if there are less costly alternatives to Voltage Supervisory Reclosing for addressing any perceived risk. The TSG will seek feedback from the DGWG during this examination, and file in Docket No. E999/CI-16-521 a report with its findings and recommendations by July 31, 2024.

The DGWG had a meeting dedicated exclusively to the topic of unintential islanding which was a great start toward accomplishing this directive. However, members of the DGWG have indicated that the July 31, 2024 deadline might be difficult to meet in light of other work and requested an extension. Staff filed an ex parte of these conversation in this docket on February 12, 2024. Staff agrees with the extension and offers an extension of the deadline to December 31, 2024 (**Decision Option 17**).

Lead Interconnection Commissioner

Commissioner Schuerger, who worked extensively in the interconnection field on behalf of the Commission, retired as Commissioner for the PUC on December 31, 2023. Commissioner Schuerger was designated the "lead commissioner" on interconnection issues pursuant to § 216A.03, subd. 9. This designation allowed Commissioner Schuerger to actively participate in the DGWG and work with Staff with greater latitude that made the interconnection discussions proceed more effectively and efficiently.

In order to achieve similar processing goals, the Commission may wish to designate a lead interconnection Commissioner to replace Commission Schuerger pursuant to § 216A.03, subd. 9 (**Decision Option 18**).

IV. Decision Options

Two Queues

1. Approve Xcel's proposal to establish two administrative queues, accepting the modifications to Sections 1.8.1, 1.8.3, and 1.8.5 of the MN DIP. (*Xcel*)
   A. Add language to MN DIP Section 1.8.3 that specifies the two queues are voluntary for Area EPS Operators that are not experiencing forty (40) complete Interconnection Applications, including Simplified Process Applications, in a year. (*Staff Proposed*)
   B. Designate applications a part of the Solar on Schools and Solar on Public Buildings legislative programs to fall under the "Priority Queue". (*Xcel proposed*)
   C. The two queues will apply toward feeders only if and when they are deemed capacity constrained. (*MnSEIA*)
   D. Modify Xcel's proposed "120% rule" for defining a "customer-sited" Interconnection Application, to instead define a "customer-sited" Interconnection Application as one whereby the total generation system annual energy production kilowatt hours alternating current is limited to 200 percent of the customer's on-site annual electric energy consumption. (*MnSEIA, AES, CCSA, SUN/ILSR/CEF*)

[OR]

2. Grant Xcel Energy a variance to MN DIP 1.8.3 to pilot its proposal establishing two administrative queues. (*The Department, SUN/ILSR/CEF*)
   A. Modify Xcel's proposed "120% rule" for defining a "customer-sited" Interconnection Application, to instead define a "customer-sited" Interconnection Application as one whereby the total generation system annual energy production kilowatt hours alternating current is limited to 200 percent of the customer's on-site annual electric energy consumption. (*MnSEIA, AES, CCSA, SUN/ILSR/CEF*)
   B. As part of the pilot, require Xcel to: (*SUN/ILSR/CEF)*
      1) investigate greater use of cluster studies to facilitate multiple interconnection requests at one time, use of storage and other advanced technologies (like advanced inverters) to mitigate delays and system upgrades, and consider options from other states that may facilitate interconnection
      2) Identify any changes necessary to the MN DIP;
      3) Model impacts of systems less than 40KW on feeders with different levels of capacity to determine effects on system operations
   C. The two queues will apply toward feeders only if and when they are deemed capacity constrained. (*MnSEIA*)

[AND] <u>If Decision Option 2 is selected, choose 3.A or B.</u>

3. The pilot's duration shall be the following months upon Commission Order: (*The*

Department, *MnSEIA*)
   A. 18 months
   [OR]
   B. 24 months

[OR]

4. Reject Xcel's proposal to establish two administrative queues. (*SUN/ILSR/CEF)*

[OR]

5. Approve Dakota's proposal to establish two administrative queues. Require Dakota to file proposed revised MN DIP language to reflect this change, for Commission approval, within 30 days of the order. (*Dakota*)

<u>If the Commission chooses Decision Option 1, 2, or 5 it may also choose Decision Option 6.</u>

6. Require Xcel to report the following in its quarterly and annual interconnection compliance filings: (*Staff Proposed*)
   A. The number of Small DER applications interconnected under the new framework adopted to prioritize small DER.
   B. Interconnection queue timelines for Small DER applications under the new framework and a comparison with timelines under the previous framework.
   C. Interconnection queue timelines for large DER applications under the new framework and, if needed, a discussion of issues large DER applications may be facing.
   D. Costs associated with implementing the new framework and a summary of the process implement under the new framework.

Capacity Reservation

<u>If the Commission chooses Decision Option 1, 2, or 5 it may also choose Decision Option 7.</u>

7. Approve Xcel's proposal to amend MN DIP Section 1.8.6 to allow Area EPS Operators the ability to reserve DER capacity. (*Xcel*)
   A. Modify Xcel's proposal so that the capacity reservation shall be applied only on a feeder by feeder level and only after adequate forecasting and analysis shows that capacity reservation is required for that particular location on the grid. (*AES*)

[OR]

8. Reject Xcel's proposal regarding capacity reservation for Small DER. (*The Department, MnSEIA, AES, Nokomis, CCSA, SUN/ILSR/CEF*)

[OR]

9. Delegate authority to the Executive Secretary to establish a Notice of Comment Period in an existing or new docket on the topic of capacity reservation for Small DER applications on the distribution system. (*Staff proposed*)

[OR]

10. Direct the DGWG to explore the necessity, risks, and benefits of establishing a capacity reservation for Small DER applications. (*Staff proposed*)

MnSEIA Proposals

11. Approve MnSEIA's proposal to modify MN DIP as follows (*MnSEIA*):
    A. Create a different screening review process for non-exporting or net-metered facilities.
    B. In the event that a facility does not pass a screen, allow the facility to obtain interconnection approval through the use of advanced inverter settings for curtailment to mitigate export in excess of grid capacity.
    C. For small projects that are not sized to load, determine the impact of the smaller project or projects on the larger projects in the queue so that those costs can be offset or otherwise compensated so the larger projects are not prejudiced.

[AND] <u>If the Commission chooses Decision Option 11, it may also choose 12.</u>

12. Request that MnSEIA file proposed modified MN DIP language to reflect these changes, for Commission approval, within 30 days of the order. (*Staff proposed*)

AES Proposal

13. Require Xcel to initiate pilot programs to develop and advance innovative solutions that will increase capacity utilization, including the use of advanced inverter settings and storage pursuant to Minn. Stat § 216B.2425, subd. 9, and Minn. Stat. § 216C.378. (*AES*)

Topic Exploration

14. Direct the DGWG to explore whether and how a new interconnection screen or interconnection track should be created for non-exporting DER applications under 40kW AC. (*Xcel, AES*)

15. Direct the DGWG to explore whether if and how battery storage systems should be evaluated under the MN DIP. Topics to discuss would include: should the battery storage and DER generation by studied on a combined basis in the interconnection process, and whether or not net-metered DER plus storage applications should be treated differently under the MN DIP than non-exporting DER plus storage applications. (*Dakota, MnSEIA, AES,*

Nokomis)

De minimis changes to the MN DIP

16. Adopt the de minimis changes to the MN DIP that Dakota identified in its November 1, 2023, proposal. (*Dakota, Xcel, the Department*)

Miscellaneous

17. Extend the deadline from par. 134 of the July 17, 2023 Xcel Rate Order regarding the DGWG's Technical Subgroup reporting and recommendations to the Commission on its unintentional islanding work to December 31, 2024. (*Staff Proposed*)

18. Designate Commissioner ______ as lead commissioner pursuant to Minn. Stat. § 216A.03, subd. 9, with authority to help develop the record necessary for resolution of interconnection issues, and to develop recommendations to the Commission in this docket. (*Staff Proposed*)