November 7, 2025

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

Docket No. E002/CI-24-288: In the Matter of Establishing Tariffs for Distribution System Cost Sharing for Interconnection in Constrained Areas

Executive Secretary Bergman,

The Joint Solar Coalition (JSC) – comprised of the Clean Energy Economy Minnesota (CEEM), Coalition for Community Solar Access (CCSA), Minnesota Solar Energy Industries Association (MnSEIA), and Nokomis Energy – and Cooperative Energy Futures (CEF) hereby submits its Initial Comments to the above-referenced docket. CCSA has electronically filed this document with the Commission and is serving a copy on all persons on the official service list for this docket. A Certificate of Service is enclosed.

Respectfully submitted,

/s/ Nick Bowman
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STATE OF MINNESOTA
PUBLIC UTILITIES COMMISSION

Katie Sieben	Chair
Audrey Partridge	Commissioner
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John Tuma	Commissioner

A. INTRODUCTION

The Joint Solar Coalition (JSC) – comprised of the Clean Energy Economy Minnesota (CEEM), Coalition for Community Solar Access (CCSA), Minnesota Solar Energy Industries Association (MnSEIA), and Nokomis Energy – and Cooperative Energy Futures (CEF) appreciate the opportunity to comment on the draft Distribution System Reactive Upgrade Process (DSRUP) developed through the Commission's stakeholder process.

We commend Commission Staff and stakeholders for their efforts to create a framework that fulfills the statutory intent of Minn. Laws 2024, Chapter 126, Article 6, Section 53 to reduce the capital burden on interconnecting distributed generation (DG) projects while enabling cost-effective and equitable distribution system upgrades that advance Minnesota's clean energy goals. This comment period comes after nearly a year of very productive dialogue among utility, agency, industry, and advocacy stakeholders. The tenor of our conversations were positive and solutions focused thanks to a shared appreciation for not only the current challenges we are trying to solve but also the opportunity to avoid further challenges in the future.

Our current interconnection processes and norms like "cost causer pays" are not built to bring distributed generation to the grid at the pace we need, let alone the pace to meet future needs. At a time when federal action has created unprecedented pressure on states like Minnesota to address its challenges on its own, improving the way we handle interconnection and grid upgrades is one significant way we can bring greater amounts of desperately needed clean energy to our local distribution grid. Following termination of the federal Investment Tax Credit ("ITC") pursuant to the Budget Reconciliation Bill enacted July 4, 2025, it will be critical that DER stakeholders work together to diminish overarching development costs for solar and solar paired with energy storage to compensate for the lost incentive revenue and allow for a continued thriving DER market in Minnesota. As interconnection costs are one of the most significant costs in the development process, the sharing of high cost infrastructure upgrades through a Reactive Cost Share Program will make a significant difference in the overarching development costs for many DER projects.

As we approach perhaps the single greatest era of load growth and demand for clean energy in decades, this framework presents a unique opportunity for Minnesota to build an ambitious, durable model for how to quickly integrate new distributed generation in a fair, efficient, equitable way.

B. DEFINITIONS

The definitions in the draft framework help to set up the structure for the Distribution System Reactive Upgrade Process. There was unanimous support in the working group for the definitions. We believe the detail in the definitions will minimize uncertainty or confusion in the program.

The JSC and CEF support the definitions presented in the draft framework with one minor edit to the definition of "Distributed Generation Project (Project)" (addition in red):

> "*Distributed Generation Project (Project): An energy generating system connected to the distribution system with a capacity no greater than ten megawatts.*"

JSC/CEF Support: All (with one small edit noted above)

C. UPGRADE COST THRESHOLDS

The JSC and CEF support a minimum qualifying cost of $1 to ensure that all upgrades providing additional hosting capacity may qualify for the DSRUP (option 1b). This approach best aligns with legislative intent to expand hosting capacity and reduce barriers to interconnection. Currently, Xcel's DER Interconnection Queue is approximately 1 GW, showing that there is great demand for DER projects to interconnect. If a higher minimum threshold is deemed necessary, our second preference is $100,000 (option 1d).

The JSC also supports no maximum cost limit (option 2c). We believe that upgrades of any cost should be allowed if they meet mobilization and cost-recovery requirements, but a maximum cost limit could be necessary in the future.

JSC/CEF Support: 1b. If not, then 1d
JSC Support: 2c

D. PRO RATA COST CALCULATION

The JSC and CEF support Staff's proposed approach to calculating pro-rata costs, which aligns with the statute by dividing total upgrade costs by total new capacity created. This ensures cost transparency, proportionality, and fairness among interconnecting customers. We also support the other provisions in this section.

The JSC and CEF strongly support subsections 3 and 4 of Section D, which provide for critical cost certainty for interconnecting customers. Minnesota's ability to rapidly and cost-effectively deploy distributed generation is dependent upon developers' ability to finance DER projects.

Financiers require cost certainty in order to invest, and charge a premium for investments with real and perceived risk.

Utility transparency, accountability, and certainty regarding distribution upgrade costs makes it dramatically easier for DER developers to secure financing for projects. Without it, investors can reasonably be expected to seek other, more reliable markets into which to invest their private capital. Currently, interconnection customers bear 100% of the risk of utility cost overruns, even in cases of utility errors, omissions or mismanagement. This is a misallocation of risk, as the party responsible for completing the work (the distribution utility) has no financial incentive to complete the work in a cost-effective manner. Conversely, the party that is paying for the work has no ability to control costs or manage performance risk.

Subsections 3 and 4 propose implementing a 25% hard cap on DER interconnection cost overruns borne by DER interconnection customers. Under this proposal, an interconnecting customer connecting to the distribution grid would be responsible for paying for distribution upgrades up to a maximum of 125% of the original cost estimate that is provided to the customer before signing an interconnection agreement. Implementing a 25% hard cap on utility cost overruns ensures that the interconnecting customer is paying for the cost of distribution upgrades while being protected against unreasonable utility cost overruns. The 25% contingency borne by the DER interconnection customer accounts for reasonable utility cost overruns caused by inflation and other factors. The proposed allowance for this 25% contingency is necessary to account for numerous factors, especially the length of time between the issuance of a cost estimate and the procurement of equipment and completion of upgrades. Subsection 4 proposes that cost overruns be borne by utility shareholders which we believe is an important protection for ratepayers and incentive for the utilities to keep costs reasonable.

JSC/CEF Support: All

E. INTERCONNECTION PROCESS

JSC and CEF largely support the Interconnection Process section as proposed, with some basic tweaks to match the thrust of stakeholder discussions held over the last year. Specifically, while the framework elsewhere allows any individual project to pay up to the mobilization threshold in order to move an Upgrade forward (F3, H8), such language was somehow omitted from Section E. Accordingly, we have proposed adding that language back into E1, E2, and E8.

Also in E8, we have removed reference to a “capacity reservation” to avoid any potential conflict with future Commission decisions and process changes, because the implementation of a capacity reservation is still under review in a number of Commission dockets. In E10, we offer simple changes to clarify language.

Finally, in E4 we offer an alternative (4c) that would allow a much more streamlined study process, which may allow utilities and developers to save both time and resources. Under this scenario, “follow on” projects that opt-in to an open Mobilization Window would not first go through system and facility study, only to be again studied later as a cluster. Instead, they would opt-in once deemed complete and, once the group of "follow on" projects hit the mobilization threshold for a given Upgrade, they would all go through a single cluster study. This would avoid duplicative work by the utility and added delay to Upgrade and Project timelines. Changes to those items are noted below.

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

   a. Participate in the DSRUP and act as a Trigger Project by signing and funding the DSRUP Agreement; or
   b. pay more than their project's Reactive Cost Share Contribution in order to reach the Mobilization Threshold
   c. Pay the full cost of the Upgrade as described in Section F2 by signing and funding the DSRUP Agreement; or
   d. Withdraw its application

2. An Interconnection Application that triggers an Upgrade shall have the option to pay for the full Upgrade, foregoing the cost sharing process and thus paying in full for the additional capacity beyond their project's need. Should the Interconnection Customer choose to fund the full Upgrade cost and forgo the cost sharing process they shall not be entitled to use excess capacity created by the Upgrade or receive any compensation from future Interconnection Customers utilizing the capacity created by the Upgrade. However, within 20 Business days from the issuance of the notice by the Utility, the Reactive Cost Share Participants may elect to pay more than their project's Reactive Cost Share Contribution in order to reach the Mobilization Threshold. Attachment A: Draft Standards for the Distribution System Reactive Upgrade Process (DSRUP)

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

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

   a. Once its Interconnection Application has completed a System Impact Study and, if necessary, a Facilities Study as required by MN DIP.

   OR

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

OR

c. after it is deemed complete.

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

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

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

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

a. Interconnection Applications in the "Awaiting Cost Share Upgrade Selection" status will maintain their queue position, and the next-in-queue project will be processed and studied through MN DIP. After completion of the System Impact Study and, if necessary, Facilities Study, next-in-queue projects will be notified by the Utility with a signature-ready DSRUP agreement. Next-in-queue projects must sign the DSRUP Agreement and pay the administrative fee within 10 Business Days of receiving notification from the Utility, elect to pay more than their project's Reactive Cost Share Contribution in order to reach the Mobilization Threshold, or withdraw

b. Next-in-queue projects will not be allowed to pay the entire cost of the upgrade under section E.2. Attachment A: Draft Standards for the Distribution System Reactive Upgrade Process (DSRUP)

c. If the System Impact Study and Facilities Study for a next-in-queue project determines that a new eligible Upgrade is required that does not fit within the scope of the existing Upgrade, then that next-in-queue project may choose to become a Trigger Project for the new upgrade following E.1 of the Standards.

d. Interconnection Applications that are processed as a next-in-queue project and have a capacity no greater than 40 kWac may proceed with interconnection if no upgrades are required and Hosting Capacity is available for applications with a capacity no greater than 40 kWac ~~through a capacity reservation.~~

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

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

JSC/CEF Support: 3, 5, 6, 7
JSC/CEF Support with edits: 1, 2, 4c, 8, 9, 10

F. MOBILIZATION THRESHOLD AND WINDOW

In the initial roll out of this new DSRUP process, it is likely that nearly all Upgrades will be fully subscribed due to the significant existing backlog in the interconnection queue and ever increasing demand for clean energy on the distribution grid. However, in the future, it will be necessary to set clear standards that allow upgrades to occur in a much more timely manner than they do under our current status quo. When setting certain standards such as the mobilization threshold and cost cap, it's important to remember the reason this new program is needed in the first place: our current interconnection process is not built to accommodate the level of distributed generation applications that our state climate goals demand. It has led to dramatic interconnection delays, congested feeders, and a tremendous amount of work before the Commission to address those challenges. When setting the course for this future program, it's critical that standards are built to address the tremendous backlog and demand for clean energy on our distribution grid.

With that in mind, JSC is supporting a 25% mobilization threshold that will allow grid upgrades to occur more quickly and capacity to be created at a greater scale. At a time of nearly unprecedented demand for new generation, we believe it is pertinent to send a clear market signal that Minnesota wants to be a leader in adding local clean energy. JSC and CEF largely support the rest of the section as drafted, with some concerns for the hypothetically sweeping impacts of 4b, which we oppose. While we appreciate the goal of having estimated costs more closely matching the true costs of Upgrade construction, 4b could unintentionally cause numerous Upgrades to be stalled in a cycle of study and restudy due to basic accounting or estimation errors.

Lastly, JSC and CEF support subsection 6 which proposes that if a Mobilization Window remains open for more than two years, the Utility may consider the Upgrade as a potential Proactive Upgrade in its next Proactive Upgrade Proposal under the framework established in Docket E002/CI-24-318. We seek to have the Reactive Cost Share Program and the Proactive Upgrade Framework work in tandem to achieve the most strategic and cost effective modernization of Minnesota's electric distribution system. This subsection allows the Reactive Cost Share Program to inform the Proactive Upgrade Framework. If an eligible Reactive Cost Share Upgrade does not meet its mobilization threshold within two years, it is likely that there is a cost barrier for interconnecting customers that could be resolved through the Proactive Upgrade Framework. As such, it would be efficient for the cost signals from the Reactive Cost Share Program to inform the Utility's Proactive Upgrade Proposal.

JSC Support: 1a
JSC/CEF Support: 2, 3, 4a, 5, 6
JSC/CEF Oppose: 4b

G. UPGRADE PRIORITIZATION

The DSRUP funds need to be strategically managed because not all Upgrades will be able to commence at the same time. This is especially true during the first few years of operation where, due to the long queues for Upgrades currently on the grid, there will be a large number of Upgrades that have enough projects in an Upgrade pool to pay for 100% of the Upgrade. Realistically, utilities cannot perform an unlimited number of Upgrades at any given time. The Upgrade Prioritization Process would ensure that, all other things being equal, the most cost effective Upgrades are constructed first. This ensures the distribution system is being built in an efficient and equitable manner.

JSC and CEF understand and appreciate the intent of Xcel Energy when they proposed G2. An Upgrade should not be able to overly delay (more than 1 year) other Upgrades because of issues that may affect that individual Upgrade. However, we have concerns with the vagueness of the wording. Utilities should define what "supply chain issues" and "permitting issues" are in practice and define a time-based criteria for an issue being resolved. Simply stating "permitting issues" or "supply chain issues" is insufficient. Furthermore, "other issues" is far too vague and could be used as a "catch-all" justification for a utility to stop any Upgrade for any reason whatsoever. We recommend that, if the commission approves this decision option, that it also require transparency best practices such as providing a narrative explanation including all information relevant to the utility determination.

For G3, JSC and CEF believe the appropriate amount of time between Upgrade review processes is three months. Six months in between Upgrade reviews is too long and would only allow for two sets of Upgrades per year. Minnesota needs to rapidly increase the amount of distributed generation on the grid due to increasing load forecasts, cuts in funding for transmission-level projects, and our state climate requirements. Having these Upgrades reviewed and prioritized every quarter is more appropriate during this time of urgency, especially during the initial period of 100% developer-paid Upgrades.

The JSC and CEF also agree that when choosing Upgrades through the DSRUP, utilities should have rebuttal presumption of prudence in cost recovery proceedings. This is because there needs to be some amount of assurance that the utility will be able to recover the cost of the Upgrade, and earn a Return on Equity, otherwise utilities would be overly cautious and hesitant to perform Upgrades and it would defeat the ultimate purpose of the DSRUP: to relieve grid congestion and get more distributed generation on the grid in order to offset increasing load and achieve Minnesota's stated climate goals.

To enable this to work well in practice, the utility must be required to provide a detailed public accounting of the cost to be recovered for each upgrade under the program. This will be valuable information for cost-benefit modeling and academic learning; but this disclosure requirement is also justified by the rebuttable presumption itself. If non-utility stakeholders have to assume that the utility is correct, then the utility must at least provide all the relevant information (including its complete analysis used to make the determination) to the non-utility stakeholders to enable them to flag any concern and (if necessary) attempt to rebut the presumption of prudence in any given case.

In terms of complaints and disputes regarding both the prioritization process and the results of that process, we believe discussion of the prioritization process itself is best handled in the Working Group to ensure stakeholders are able to continue productive dialogue on these issues or petition the Commission for a change in the process. If, however, final prioritization decisions lead a party to dispute a formal prioritization result, we agree those disputes are best handled through the formal complaint process.

JSC/CEF Support: 1, 3a, 4, 5, 6
JSC/CEF Oppose: 2

H. PAYMENT DETAILS

Regarding the ability for DSRUP participants to withdraw their interconnection agreement, the JSC and CEF support no fees being assessed to companies that withdraw. The loss of their Cost Share Contribution is sufficient incentive to only withdraw when absolutely necessary.

The JSC and CEF strongly support subsection 6, which allows interconnecting customers to use surety bonds and/or letters of credit to pay for cost share contributions. The actual cash payments that are secured by the Bonds, would become due and payable to the utility in alignment with utilities' actual spending/costs incurred. In practice we think that this either means payments at COD or in arrears, as the utility completes the work or makes payment to third parties.

Interconnecting customers triggering complex infrastructure upgrades are required to make interconnection deposits prior to receiving project specific information on an uncertain timeline. In many circumstances this means that deposits are required years in advance of high-level substation commissioning timelines. For many projects this payment is in excess of one million dollars. The size of these carrying costs and the uncertain timeline often results in projects becoming unviable and unable to move forward to interconnection. The DSRUP process has the potential to exacerbate this problem, with higher costs and more uncertain timelines. This has the potential to lead to mobilization thresholds not being met and a less efficient implementation of the Cost Share Program.

Further, many interconnecting customers are developers that typically sell the projects they develop, which means that they finance their deposits at considerable expense. For cash financing, at 13% for a one million dollar project over 4 years, the project will incur $520,000 in interest. It is very likely that for many projects, a requirement of such a large cash outlay years ahead of operation will erode project economics and threaten project viability. Bonds have a much lower carrying cost than cash (~one percent paid annually versus 13% paid quarterly). Bonds could be utilized in these circumstances to allow for delay in actual cash payment until a time closer to project specific PTO, which would greatly diminish the carrying cost and risk to interconnecting customers. Requiring utilities to accept letters of credit and bonds for interconnection deposits and invoicing for cash once construction is complete or in alignment with actual spending/costs incurred, will mitigate excessive carrying costs while still providing the utilities with the security that an interconnection customer will fulfill its contractual obligations to pay its interconnection costs.

The goal of the statute is to "allow for the interconnection of distributed generation facilities" at congested or constrained locations on the grid. Clause 2 of the statute states that its goal is to "reduce the capital burden on owners of trigger projects seeking interconnection." Requiring utilities to accept letters of credit and bonds for interconnection deposits and invoicing for cash once construction is complete or in alignment with actual spending/costs incurred, will facilitate these goals.

The JSC, with the exception of MnSEIA, supports the use of the existing cost share programs to cover the cost of pro-rata fees for DSRUP upgrades. MnSEIA will file comments addressing its views on this matter in a supplemental filing. The statute is clear that anyone using unsubscribed capacity created by a DSRUP upgrade must pay a pro rata fee, as Clause 7 of the statute prohibits "owners of distributed generation facilities from using any unsubscribed capacity at an interconnection that has undergone an upgrade without the distributed generation owners paying the distributed generation owner's pro rata cost of the upgrade." This, in addition to the use of a blanket capacity reservation which continues to be in contention in various Commission proceedings, leads CCSA, CEF, and Nokomis to oppose H.11. But we strongly support both the use of existing cost sharing programs to cover the cost of under 40kw projects and the expansion of those cost sharing programs to ensure all small system costs are more equitably covered.

JSC/CEF Support: 1, 2, 3, 4 over 5, 6, 7, 8, 9, 10, 12
CCSA, CEF, Nokomis Oppose: 11

I. PAYBACK PERIOD

The JSC and CEF support a Payback Period of at least five (5) years before ratepayers have to cover the DSRUP costs (option 1.a.i.). If at least 75% of the costs have not been recovered after five years, we support extending the Payback Period by an additional three (3) years. This extended period ensures that interconnection customers are paying for the relevant upgrades and minimizes impacts to ratepayers. We have concerns that Subsection 3 may either need to be tweaked or reworked to have the correct impact. In any given payback period, there may be many interconnection applications that are deemed complete that don't choose to opt-in to a given mobilization window and would not, therefore, be subject to the respective cost share contribution. It's possible that 3 was meant to speak to any application that is deemed complete *and opts into a mobilization window* but we won't speculate.

JSC/CEF Support: 1ai, 2
JSC/CEF Oppose or tweak: 3

J. ANNUAL RATEPAYER COST CAP

The Annual Ratepayer Cost Cap refers to the total amount of capital spent on distribution capacity Upgrades that can be allocated to ratepayers at any given time in the DSRUP. It is not an "**annual**" cost cap, as traditionally thought of, but rather a rolling dollar amount that changes as new Upgrades get constructed (if they are not immediately 100% developer-paid) and/or the payback period ends on specific Upgrades.

Due to existing demand in the interconnection queue and the significant demand for more clean energy on the distribution grid in the future, the Annual Ratepayer Cost Cap is not likely to come into play for the foreseeable future, at least the first 3-15 years of the DSRUP. This is due to the fact that the grid is currently extremely congested. In the short term, queue demand will mean that every Upgrade will be funded almost entirely through Projects' pro rata contributions. Upgrades that immediately have 100% of their costs paid for by DSRUP participants are the Upgrades that are performed first. Because these Upgrades have 100% of their costs already paid for, there is no risk of adding to the amount in the Annual Ratepayer Cost Cap. And, even once the existing queue is less congested, it is still likely that dramatic load growth and the need for generation along with it will create significant demand for clean energy on the distribution grid for years to come.

We expect the amount in the Annual Ratepayer Cost Cap will be zero until the concept of mobilization thresholds (and risk to ratepayer dollars) comes into play, which we predict will likely be three to five years depending on the operational budget. The larger the operational budget, the shorter this period of 100% developer-paid for Upgrades will be and the quicker the concept of the Annual Ratepayer Cost Cap will come into play. Furthermore, if the commission chooses a Payback Period, and if the Payback Period is somewhere between 5-10 years (as is being proposed in this framework), these two factors together would extend the amount of time before the Annual Ratepayer Cost Cap comes into play to somewhere between 8-15 years.

The JSC and CEF recommend that the commission approve 2b, that the Annual Ratepayer Cost Cap shall not exceed 11% of the annual average of the Utility's forecasted 5-year distribution capital budget from its most recent Integrated Distribution Plan. Based on the most recent filings, that figure would mean roughly $95 million. Further, Xcel Energy's 2023 Integrated Distribution Plan states that it plans to spend $190M on "proactive system upgrades to increase DER hosting capacity."[1] This number, and more specifically the percentage of the annual average forecasted 5-year distribution capital budget, provides us with a helpful benchmark for all utility spending on upgrades to accommodate DERs. As indicated by our chosen number ($95M or 11%), we are proposing the utilities reserve, for the Annual Ratepayer Cost Cap, half of the amount of capital (percentage-wise) than what Xcel predicted it would spend, in its 2023 IDP, on "proactive system upgrades to increase DER hosting capacity."

Because grid Upgrades made through the proactive process are still being discussed and finalized through the Phase 2 process, we propose a spending cap on the reactive program that fully leverages private developer dollars. If these standards establish a low Annual Cost Cap, we will hinder the ability for multiple Upgrades to be performed simultaneously – which will significantly delay the interconnection of desperately needed distributed energy resources.

In addition, we acknowledge that the speed with which Upgrades are constructed will also be limited by utility's ability to meet real world construction challenges – no matter how large a program cap is set in these standards. With that in mind, and as Federal changes have created even further urgency for clean energy projects, we urge the Commission and our utilities to set more ambitious operational budgets to ensure that Upgrades with clearly demonstrated Project demand are able to more quickly be constructed and put into service.

On J2, the JSC and CEF agree that the Annual Ratepayer Cost Cap should remain in effect for a period that will give observers of the Annual Ratepayer Cost Cap sufficient time to analyze the

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[1] Xcel Energy 2023 IDP, page 21; (https://www.xcelenergy.com/staticfiles/xe-responsive/Company/Rates%20&%20Regulations/Regulatory%20Filings/202311-200132-09.pdf).

effectiveness of any given Annual Ratepayer Cost Cap. It's possible 24 months is necessary but we are open to a shorter annual guideline, as well.

We also agree that a Utility, prospective Trigger Projects, and ratepayer advocates should be able to request a modification to the Annual Ratepayer Cost Cap and that, when considering a possible modification, the commission should consider, at a minimum, previous and future ratepayer costs and risks arising from the Utility's DSRUP, total pending cost share contributions, and the demand for new Upgrades. These adjustments, and others, should initially be handled by the Working Group to ensure parties are able to continue productive dialogue and progress.

Regarding J4, we believe it is crucial that any portion of the cost of Upgrades that have not been paid for by Reactive Cost Share Contributions because the Payback Period has expired should not count toward the Annual Ratepayer Cost Cap. In other words, once the Payback Period on an Upgrade expires, the costs should be recorded but taken out of Annual Ratepayer Cost Cap and socialized. Without this important procedural mechanism, the Annual Ratepayer Cost Cap would very quickly be reached and the entire DSRUP program would grind to a halt until enough Upgrades were 100% paid for during their Payback Windows that the amount in the Annual Ratepayer Cost Cap would decrease. Even worse, there would come a time when the entire cap would be taken up by socialized costs and there would be no way to bring down the amount in the Annual Ratepayer Cost Cap through fully paying off upgrades because these socialized costs would be permanently in the cap without a mechanism for removing them, This would grind the DSRUP to permanent halt.

We also believe that if some of the costs of Upgrades through the DSRUP are socialized, it should be considered acceptable since bringing DERs onto the grid and offsetting distribution spending while upgrading the distribution system as a whole offers many benefits to all ratepayers. The amount of costs being socialized will be reported in the compliance filings and parties can debate whether this amount is justifiable but adding the socialized costs of the DSRUP program to the Annual Ratepayer Cost Cap assumes that the DSRUP program is adding no benefit to ratepayers which is untrue.

We also agree that once the Annual Ratepayer Cost Cap is reached the Mobilization threshold should move to 100% but only if Decision Option 4 is chosen.

JSC/CEF Support: 1, 2b, 4, 4a, and 5 (assuming 4a is chosen)

K. COST RECOVERY

Our main recommendation is that the commission choose Decision Option 6b. However, if the commission chooses to adopt any combination of Decision Options 1, 2, or 3, we would recommend the commission adopt Decision Option 1 (outstanding costs are not eligible for recovery during the first five years of the Payback Period and after that the remaining costs shall be eligible for recovery) and Decision Option 3b (the utility shall accrue carrying costs during the initial 5 years of the Payback Period and the percentage rate for those carrying costs shall be calculated at the utility's long-term cost of debt). We believe that, if the commission believes the utility should abide by a five-year delay before upgrade costs are placed into rates (Decision Option 1), then the carrying costs should **not** be calculated at the Weighted Average Cost of Capital (WACC). If carrying costs are equal to the WACC, then the carrying costs end up being the same as rate-base costs, making the five-year delay in Decision Option 1 much less useful to ratepayers. The utility will earn its full return on the remaining costs that go into rate base after the five-year delay, but during the five-year delay period, which is intended to protect ratepayers, carrying costs at the long-term cost of debt (Decision Option 3b) would be much more reasonable than at the utility's full WACC (Decision Option 3a).

We express no opinion at this time on whether Xcel should be able to accrue and capitalize carrying costs under this scenario, and defer to the Office of the Attorney General and the Department of Commerce on this issue.

As stated above, the JSC and CEF recommend that the commission choose Decision Option 6b. If the commission does choose 6b, it can reject Decision Options 1, 2 and 3. We feel that the Reactive Cost Share Contributions collected from Reactive Cost Share Participants should immediately be applied to offset the rate base amount of the Upgrade until the upgraded assets are fully paid down. This lowers the amount of rate base the utility earns a return on, but it is less expensive for the ratepayers in the long run. The economic incentives for the utility seem to be sufficient as is without having an even higher rate base to profit from. It is more important to avoid extra costs for ratepayers.

JSC/CEF Support: 6b, if not 6b then 1, 3b and 3c. 4, 5a, 5b
JSC/CEF Tentative/Oppose: 5c, 5d

L. COST ALLOCATION

JSC and CEF believe that Decision Option 2 is the more appropriate option. If there are DSRUP Upgrades that are primarily serving commercial or industrial customer classes and those Upgrades have some of their costs socialized, those Upgrades should be tracked separately and allocated to the commercial and industrial classes which are benefiting from the Upgrade. This logic follows common sense cost allocation principles and in particular the beneficiary pays methodology. Even though every individual large commercial or industrial customer may not benefit from any given Upgrade, the class as a whole benefits and therefore it is more justified to charge that class rather than the residential classes.

It also makes sense to follow established rate case allocators and revenue requirement procedures for all other DSRUP Upgrades and other parties to a rate case should be able to request the commission change the established cost allocation procedures for DSRUP Upgrades.

Even though there are no specific proposals regarding how to identify or mitigate adverse bill impacts on under-resourced customers and/or small businesses, we believe the commission should choose Decision Option 3 so that, in the future, ratepayer advocates, or others, can easily raise this issue and this Decision Option explicitly states this is allowed within the DSRUP framework.

JSC/CEF Support: 2, 3.
JSC/CEF Oppose: 1

M. PUBLICATION OF DSRUP INFORMATION AND DATA

The JSC and CEF support all options in Section M as we believe that publication of DSRUP information and data will be crucial to the program's success. Community solar companies need to easily access information such as the $/kW Pro Rata Cost to participate in the Upgrade, the start and end dates of the Mobilization Window and the start and end dates of the payback period in order to determine which DSRUP sites are the best candidates for engagement.

JSC/CEF Support: All

N. REPORTING AND PROCESS EVALUATION

The JSC and CEF support all options in Section N as we believe that reporting and process evaluation are necessary to track the progress of the DSRUP. Reports should include the details listed in the draft framework so that the PUC and others can gain a better understanding of the status of various DSRUP sites.

JSC/CEF Support: All

O. DISPUTE RESOLUTION

It makes sense for more formal complaints to follow existing MNDIP dispute processes (as largely described in Attachment B) but we are also hopeful that as adjustments and smaller improvements are needed in the prioritization process and other program details they can be first brought to the DSRUP Working Group in an attempt to solve basic challenges in a collaborative and nimble manner.

JSC/CEF: Tentative support

P. TARIFF IMPLEMENTATION

The JSC and CEF support all options in Section P. Implementing these standards through a tariff is the most logical approach.

JSC/CEF Support: All

ADDITIONAL ISSUES OF NOTE

Meeting increasing demand for electricity in Minnesota and achieving the state's clean energy mandates requires the rapid and cost-effective deployment of DERs. A reliable interconnection process, with accurate cost estimates and binding interconnection agreements, is foundational to Minnesota's ability to attract private capital to finance and deploy DERs with reduced reliance on ratepayer-funded incentives. To ensure the success of the Reactive Cost Share Program, it is essential that the framework provide for cost certainty to allow DER developers to make large-scale investments with regulatory certainty of cost, timeline and risk. To ensure sufficient cost certainty in this program, JSC and CEF recommend consideration of the following measures:

> **Increase Detail in Impact Study Cost Estimates**: Require utilities to provide itemized, equipment-level cost breakdowns (including labor, materials, and allowable contingency) in their cost estimates for distribution upgrades. This increased granularity will provide interconnection customers with a transparent understanding of what utility infrastructure they are paying for and what factors are driving costs.
>
> **Establish Annual Cost Matrix Filings**: Direct Minnesota's utilities to publish and update matrices with itemized actual costs for common distribution upgrades. This process will provide the Commission and DER stakeholders with greater transparency into utility costs and ensure that changes to cost estimation are informed by the utilities' true costs of distribution upgrades.
>
> **Require Itemization on Reconciliation Statements**: Direct Minnesota's utilities to provide interconnection customers with a detailed, itemized, clear statement of final costs for all distribution upgrades, including explanations for variances exceeding 125% of the original estimate. This is a much-needed improvement to the current reconciliation process, whereby utilities either provide minimal detail or inscrutable invoices/receipts that cannot be reviewed or analyzed in a reasonable manner.
>
> **Require Acceptance of Both Letters of Credit and Bonds for Interconnection Deposits:** Interconnecting customers triggering complex infrastructure upgrades are required to make interconnection deposits years in advance of high-level substation commissioning timelines, resulting in multi-year carrying costs. Bonds have a much lower carrying cost than cash (~one percent paid annually versus 13% paid quarterly). And could be utilized in these circumstances to allow for delay in actual cash payment until a time closer to interconnection, which would greatly diminish the carrying cost and risk to interconnecting customers.

CONCLUSION

We want to close by thanking all stakeholders that took part in this process for their hard work and, more specifically, their commitment to such a productive and cordial environment. For nearly a year, this group poured through dozens and dozens of substantial and challenging topics and, at every turn, kept a calm and outcome-focused tenor in every single conversation. This is, of course, thanks to the very intentional work and leadership by Commission staff. But it also is thanks to the continued commitment by every single party to stay laser-focused on building a framework that could be truly successful for all involved at every step in the process.

As with any new program or regulatory process, there will no doubt be bumps along the road and an immense amount of learning and growing pains. And, even if this process has required an immense amount of time and energy from us and our fellow stakeholders, it's clear that those efforts were well worth the investment.

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