December 10, 2025

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

Re: In the Matter of Northern States Power Company, dba Xcel Energy, Petition for Approval of Capacity*Connect, a Distributed Capacity Procurement (DCP) program
Docket No. E002/M-25-378

Executive Secretary Bergman,

Please find enclosed the comments of the Coalition for Community Solar Access, the Minnesota Solar Energy Industries Association, and the Solar Energy Industries Association, collectively the Joint Solar Parties (JSP). The JSP respectfully submits these comments in response to the Notice of Comment Period issued by the Minnesota Public Utilities Commission on October 16, 2025, and the Notice of Extended Comment Period issued on November 21, 2025.

Together, the JSP represents a combined membership of more than 1,200 organizations nationwide—developers, installers, financiers, manufacturers, other nonprofits and advocacy groups, public agencies, and service providers working across dozens of mature and emerging distributed solar and storage markets. This breadth of experience provides our members with a deep, practical understanding of how programs like the one under consideration function on the ground. Their day-to-day work developing, financing, and operating distributed solar + storage projects gives them invaluable insight into what makes such programs successful, what pitfalls to avoid, and how to ensure benefits flow equitably to ratepayers and consumers.

Throughout this process, the JSP have worked diligently to bring our memberships along—facilitating discussions, gathering input, and striving to reach a constructive place of conceptual support while still raising important concerns. Those concerns arise not from opposition but from the collective wisdom of experienced market participants who want Minnesota to get this right. Our comments are offered in a collaborative spirit, grounded in a desire to help the Commission refine key details so that this program, if implemented, is durable, cost-effective, consumer-protective, and capable of delivering real value to Minnesota communities.

The JSP looks forward to continued collaboration with the Commission, the Department of Commerce, the Attorney General, utilities, and all stakeholders to ensure the thoughtful deployment of distributed energy resources that will benefit Minnesota for years to come.

Sincerely,

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In the Matter of Northern States Power Company, dba Xcel Energy, Petition for Approval of Capacity*Connect, a Distributed Capacity Procurement (DCP) program.

INITIAL COMMENTS of CCSA, MnSEIA and SEIA, Collectively the Joint Solar Parties (JSP)

December 10, 2025

Docket No. E002/M-25-378

EXECUTIVE SUMMARY

The JSP supports the development of distributed energy storage and Virtual Power Plant (VPP) programs that advance Minnesota's clean energy goals. Xcel Energy (Xcel) is wise to pursue front-of-the-meter storage, and it is encouraging to see utilities more broadly recognizing the value that DERs deliver to the grid, including their potential to reduce system costs and enhance flexibility. However, Xcel's proposed Phase 2 of Capacity* Connect (C*C) raises serious concerns about how we procure these resources and whether the process delivers the best value for customers and the system. The proposal is costly, shifts undue risk to ratepayers, restricts competitive market participation—commonly found in other resource solicitations–omits required analyses of alternatives, and could restrict the continued growth of Minnesota's distributed energy resource (DER) ecosystem while failing to meaningfully advance it. Utility ownership of front-of-meter (FTM) battery energy storage systems (BESS) should be permitted only when Xcel demonstrates, through solicitation of proposals, that competitive alternatives cannot meet the identified system needs at lower cost or lower risk to ratepayers. As it stands, the C*C proposal does not meet that rigorous standard, and would be pursued only at elevated cost, through a solitary implementation partner.

The JSP recommend that the Commission approve Phase 2 **only with key modifications**, including:

1. **Competitive Procurement**: Phase 2 should be redesigned around an open, competitive process, with Sparkfund serving as program administrator and procurement manager, rather than as an implementation partner.

2. **Third-Party Development & Ownership**: The remaining 600 MW identified in the IRP should be allocated to third-party developers, with utility-owned assets limited to situations where third-party alternatives cannot meet system needs at lower cost.
3. **Ratepayer Risk Mitigation**: Development and performance risks should rest with private developers, and utility-owned assets must meet strict performance obligations.
4. **Expanded System Benefits**: Xcel should deploy use cases that relieve feeder congestion, increase hosting capacity, and build an open-access DERMS platform that allows participation by customer-owned and third-party DERs.
5. **Comparative Analysis**: The Commission should require Xcel to conduct the missing analysis comparing utility-owned vs. third-party-owned DERs, including proven pay-for-performance VPP models.
6. **Interconnection Integrity**: Any modifications to the Minnesota DIP interconnection process must preserve fairness for all DER projects and include strict guardrails if queue bypassing is allowed.
7. **Cost Recovery & Budget Oversight**: C*C costs are significantly higher than comparable programs; RES Rider recovery should only apply to storage paired with carbon-free generation, and the Commission should require a full 20-year budget and cost reductions.
8. **Equity Considerations**: Any program design should address disproportionate impacts on low-income communities and encourage deployment in underserved, outage-prone areas.

If these modifications are not adopted, the JSP recommend that the Commission **approve only a limited Phase 2**, contingent on Xcel demonstrating positive benefit-cost ratios, expanded use cases, and an open DERMS integration path.

In short, while the JSP support distributed storage and VPP-like programs, Xcel's current Phase 2 proposal is not ready for full approval. Major design changes are needed to protect ratepayers, preserve competitive markets, and advance Minnesota's clean energy transition.

INTRODUCTION

The Coalition for Community Solar Access (CCSA), the Minnesota Solar Energy Industries Association (MnSEIA), and the Solar Energy Industries Association (SEIA), collectively the Joint Solar Parties (JSP) respectfully submit these comments in response to the Notice of Comment Period, issued by the Minnesota Public Utilities Commission (Commission or PUC) on October 16, 2025, and Notice of Extended Comment Period issued on November 21, 2025.[1]

CCSA is a 501(c)(6) nonprofit trade organization focused on supporting the community solar industry through legislative and regulatory efforts. CCSA's mission is to empower every American energy consumer with the option to choose local, clean, and affordable distributed solar and storage projects, including community solar. CCSA works with customers, utilities, local stakeholders, and policymakers to develop and implement policies and best practices that ensure front-of-the meter distributed solar and storage, including community solar programs, provide a win for all, including customers and the grid.

[1] Minnesota Public Utilities Commission, Notice of Comment Period, Dkt.25-378 (Oct. 16, 2025). Minnesota Public Utilities Commission, Notice of Extended Comment Period, Dkt.. 25-378 (Nov. 21, 2025).

CCSA has over 120 member companies and is active in virtually all state-level community solar markets, as well as at the federal level.

SEIA, a 501(c)(6) nonprofit trade organization established in 1974, is the national trade association of the United States solar energy and energy storage industries. Through advocacy and education, SEIA and its roughly 1,200 member companies are building strong solar and storage industries to power America. A substantial number of SEIA member companies are in operation in Minnesota working in all market segments – residential, commercial, community solar, and utility-scale – representing millions of dollars of in-state investment and a significant number of Minnesota solar and energy storage jobs. SEIA member companies also provide solar panels and battery storage systems, financing, and other services to many projects in Minnesota and throughout the country.

MnSEIA is the voice of Minnesota's solar and storage industries. With a diverse membership of more than 170 companies and organizations—employing over 5,000 Minnesotans across installation, development, manufacturing, nonprofit, and utility sectors—MnSEIA works to advance and defend the solar and storage policies that empower households, businesses, and communities statewide. Our coalition drives innovation, creates local jobs, and ensures that all Minnesotans can benefit from affordable, reliable clean energy.

BACKGROUND & CONTEXT

On October 3, 2025 Xcel filed a petition for approval of C*C pursuant to the Commission approving a settlement agreed to by stakeholders in Xcel's Integrated Resource Plan (IRP) proceeding. The initial proposal, as outlined in the IRP, permitted Xcel to pursue the DCP as a kind of VPP intended to leverage Xcel's planning and procurement capabilities to facilitate system wide benefits from the deployment of Distributed Energy Resources (DERs).[2] IRP Order Point 23 required the DCP program proposal to include:

a. An evaluation of how the Distributed Capacity Procurement program could be used to improve equity.
b. A discussion of how the proposal impacts the Five-Year Action Plan approved in this order, how it impacts the IRP forecasted annual distributed generation solar additions, and whether the DCP could be used to advance compliance with the distributed solar energy standard.
c. An evaluation of a costs and benefits comparison between a utility-owned and managed DCP model and alternative models allowing participation from customer owned and third party-owned resources.
d. An evaluation of the labor standards utilized by Xcel and third-party solar installers.[3]

The organizations comprising the JSP are longtime Distributed Energy Resources (DER) advocates who have—for years—championed the use of DER technologies (including battery storage, solar generation, aggregation, and energy efficiency measures) and have built the necessary supply chains

[2] Minnesota Public Utilities Commission, *In the Matter of Xcel Energy's 2024–2040 Upper Midwest Integrated Resource Plan*, ORDER APPROVING SETTLEMENT AGREEMENT WITH MODIFICATIONS, Docket No. E-002/RP-24-67, April 21, 2025, at 12.
[3] Id, at 24.

to competitively deliver systemwide benefits. We are gratified that Xcel now appreciates and agrees that DERs are capable of providing significant systemwide value and supports the shift toward integrating DERs into distribution system planning processes. This recognition is consistent with what national experts and the Department of Energy have recognized.[4]

However, integrating DERs into the planning framework does not require—nor justify—utility ownership or utility-controlled project development as the default model. The technical merits of distribution-connected storage, DERs, and VPPs do not depend on what party owns the asset; they depend on transparent planning, clear operational needs, and a well-designed program structure.

Introduction to Virtual Power Plants

Xcel's proposal states that C*C assets "could be considered a virtual power plant" because the assets would be located on the distribution system, aggregated and operated to meet overall Xcel system needs and serve all customers. The C*C proposal shares similarities to traditional VPPs, however it is distinctly different from VPPs in critical ways. Our comments provide an introduction to VPPs to help compare and contrast Xcel's C*C program with a traditional VPP program. The U.S. Department of Energy's [Pathways to Commercial Liftoff: Virtual Power Plants report] provides a clear, foundational explanation of what VPPs are and how they operate. The following summary is intended to support the Commission's understanding of VPPs.

The Department of Energy (DOE) defines VPPs as aggregations of DERs that can balance electricity demand and supply and provide utility-scale, utility-grade grid services equivalent to a traditional power plant.[5] These resources may include smart thermostats, electric vehicle (EV) chargers, battery energy storage systems (BESS), solar-plus-storage systems, commercial and industrial equipment, and other flexible loads.[6] VPPs operate through a unifying control and communication architecture that enables these individual devices—each acting independently in the customer's home or business—to function collectively as a predictable, dispatchable grid resource. This includes:

- Demand DERs (e.g., smart thermostats, smart water heaters, EV chargers, commercial HVAC)
- Storage DERs (BESS, EV batteries)
- Generation DERs (rooftop solar, community solar paired with BESS, fuel-based generators)[7]

VPPs can provide multiple grid services, including:

- Peak Demand Reduction (Demand Response): Most existing VPPs operate by reducing electricity consumption during times of grid stress. DOE notes that 30–60 GW of today's VPP capacity consists primarily of demand response programs.[8]

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[4] U.S. Department of Energy, PATHWAYS TO COMMERCIAL LIFTOFF: VIRTUAL POWER PLANTS, (September 2023).
[5] U.S. Department of Energy, PATHWAYS TO COMMERCIAL LIFTOFF: VIRTUAL POWER PLANTS, (September 2023), p. 6.
[6] Id, p.2.
[7] Id, p.6.
[8] Id, p.3.

- Load Shifting & Load Shaping: By adjusting when DERs consume or produce power—such as shifting EV charging overnight or pre-heating water heaters—VPPs help flatten peaks and align demand with low-cost, clean generation.[9]
- Local Distribution Grid Support: VPPs can help alleviate local distribution system constraints by reducing demand on overloaded feeders or substations.[10]
- Distributed Generation & Storage Dispatch: Some VPPs can discharge batteries or utilize solar-plus-storage systems to support the grid, functioning similarly to small modular power plants.[11]
- Ancillary Services: VPPs may provide frequency regulation, voltage support, and fast-response services historically provided by centralized generators.[12]

When VPP resources are deployed by utility customers behind-the-meter (BTM), ratepayers are fully insulated from financial and performance risk. All costs, operational responsibilities, and potential underperformance are borne entirely by private asset owners and aggregators, ensuring that ratepayers are not exposed to stranded assets or cost overruns. A similar risk allocation can be achieved with front-of-the-meter (FTM) resources when they are owned and operated by a third-party aggregator. In this model, an independent company can deliver the same suite of grid services—capacity, energy, and ancillary services—while assuming both the investment risk and the obligation to perform. By contrast, FTM resources owned by a utility shift the financial risk to the utility's balance sheet and, absent specific regulatory protections, ultimately to captive ratepayers. This distinction underscores that BTM and third-party-owned FTM approaches provide the benefits of VPPs while shielding customers from financial exposure, whereas utility-owned FTM resources require more careful regulatory scrutiny to ensure ratepayer protections.

The JSP fully support the development of VPPs to rapidly meet growing system demands, while keeping costs down for ratepayers. A brief literature review of VPP programs and potential shows that the net benefits to ratepayers are usually strongly positive. The Rocky Mountain Institute (RMI) found that VPPs could reduce peak demand by 60 GW by 2030.[13] The Brattle Group found that VPPs could save utilities $15-35 billion in capacity investments by 2032.[14]

Finally, a primary focus of DOE's VPP report was on affordability for ratepayers. The report finds that one of the main advantages of deploying VPPs at scale is reducing capital expenditures of investor owned utilities. Specifically, "[i]n addition to benefitting from avoided grid costs, Americans will benefit from spending on VPPs because the majority of VPP costs flow to participating energy consumers in the form of incentive payments (instead of paying for fuel and capital investments in utility-scale infrastructure)."[15] This claim is also supported by the aforementioned RMI and Brattle Group studies.

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[9] Id,   p. 8-9.
[10] Id, p. 12.
[11] Id, p. 6-8.
[12] Id, p. 18-19.
[13] Rocky Mountain Institute, *"Virtual Power Plants, Real Benefits"*(January 2023), p. 5.
[14] The Brattle Group, *"Real Reliability: The Value of Virtual Power"* (May 2023) p. 5.
[15] "*Pathways to Commercial Liftoff: Virtual Power Plants*," p. 11

It bears repeating that with a BCR of 0.96 under the most favorable estimates, but significantly lower under less favorable estimates, the C*C program has the potential to not realize the promised cost savings of a differently structured VPP.

C*C as a Form of VPP

C*C shares some similarities with VPPs, but differs from the VPP model in significant crucial ways. Like other VPPs, C*C assets would be located on the distribution system and serve the primary goal of balancing electricity supply and demand by aggregating C*C resources to meet systemwide needs. Like VPPs, C*C asset aggregation and operation would occur under the unified operation framework enabled by a DERMS.

C*C differs from traditional VPPs in ownership structure, participation, and market access. Traditional VPPs are technology-agnostic portfolios of customer-sited and third-party-owned resources—both BTM and FTM—that voluntarily enroll participants to provide services in response to transparent market signals. Participation is open, competitive, and decentralized. By contrast, C*C participation is restricted to utility-owned assets developed and implemented through a single commercial partner. No other developers, aggregators, or customers may participate. This structure is unprecedented in VPP programs and raises significant competitive-market concerns. Traditional VPPs leverage third-party ownership, customer enrollment, and competitive aggregation to provide valuable system services at the most cost-effective rates. C*C, as proposed, is a utility-owned, utility-controlled asset class that does not send market signals and does not allow third-party participation. C*C restricts market opportunity by restricting participation to exclusively utility owned and controlled assets and obfuscating market signals from the competitive, private market, which would allow costs that exceed market rates.

Risk Allocation

In established VPP models, private asset owners and aggregators bear all investment risk, operational responsibility, and the consequences of underperformance. Ratepayers benefit from performance-based structures without underwriting the capital costs of the portfolio. This same risk allocation can be achieved with FTM resources when they are procured through competitive, services-based contracts, where independent companies own the assets and deliver capacity, energy, and distribution-level services under performance obligations.

C*C shifts the entirety of the financial risk allocation back to ratepayers. All costs, operational responsibilities, and potential underperformance are borne by ratepayers, and the capital expenditure required by the utility is increased to fulfill the budget required to pay for utility owned infrastructure. Xcel will recover all of the capital costs of the program, including any cost overruns, through rates. C*C assets will be included in rates and paid for by utility customers, and the risk of underperformance will fall back on ratepayers, regardless of whether those assets deliver the expected system wide benefits. In other words, ratepayers underwrite the infrastructure; the utility captures the guaranteed return. This is the opposite of how risk is allocated in market-driven VPPs and competitive FTM storage models that rely on private capital rather than the rate base.

In summary, C*C shares some operational and DERMS-related features with VPPs, but functionally it is a utility-owned, utility-developed, front-of-the-meter storage portfolio. The Commission's central question is, therefore, not whether C*C resembles a traditional VPP, but whether Minnesota should allow this new asset class to be deployed through a monopoly-ownership and development model or through a competitive, performance-based framework that preserves market access and protects ratepayers.

Concerns About Approving The C*C As a Kind of VPP

First, a primary concern as DER advocates is the precedent set by approving a program that costs ratepayers more than it benefits them. In the long term it will be harder for regulators to support further use of BESS to provide capacity, reliability and other grid services, if C*C is approved despite the fact that its quantifiable costs exceed its quantifiable benefits. A well designed VPP program would provide benefits to ratepayers that are greater than program costs.

Market driven VPP programs are operational in 22 states and none of them were approved on the basis of a cost-benefit ratio that could potentially be as low as .68.[16] The C*C is expensive. The estimated price tag for C*C is $2,150 per kW for 200 MW of BESS Deployment, while Xcel's own Advanced VPP (AVPP) program in Colorado[17] will cost an estimated $624 per kW for 125 MW.[18] In addition to being expensive, the benefits of C*C are not clearly articulated. It's clear from the filing that even Xcel doesn't yet understand the full extent to which C*C could benefit ratepayers.

Second, solar and storage developers are concerned about utilities expanding their monopoly into competitive markets, specifically regarding Front-of-the-Meter (FTM) battery storage. This proposal would give the utility an unfair competitive advantage on project ownership, and project development.[19] By presuming utility ownership, C*C eliminates the market mechanism that true VPP programs employ to leverage competition, encourage performance and reduce costs and financial risk exposure for ratepayers.

[16] JSP Appendix A.

[17] Colorado Pub. Utils Comm'n, Proceeding Nos. 24A-0547E and 25A-0061E, Hearing Exhibit 131, AVPP Program Settlement Agreement, filed Aug. 15, 2025; 24A-0442E, PUC Oral Deliberations on PSCo JTS, (Aug. 13, 2025), at 3:52:35 – 3:53:30, https://www.youtube.com/watch?v=m-VmvCF0ZRo&t=14392s

[18] Minnesota Phase 2 DCP Target Capacity: 200 MW with a proposed budget of $458,500,000 ($458,500,000 / 200,000 kW = $2,292.50 $/kW). Colorado AVPP Target Capacity: 125 MW with a proposed budget of $79,000,000 ($79,000,000 / 125,000 kW = $632 $/kW).

[19] The Minnesota Department of Commerce has recognized that allowing a for-profit electric utility into a competitive marketplace "risks that the private sector will face unfair competition from monopoly utilities." Minnesota Department of Commerce, DIRECT TESTIMONY AND ATTACHMENTS OF MATHEW LANDI ON BEHALF OF THE DIVISION OF ENERGY RESOURCES OF THE MINNESOTA DEPARTMENT OF COMMERCE, Dkt. 22-432, p. 110 (Feb. 7, 2023); *see also*, Ohio Attorney General, https://www.ohioattorneygeneral.gov/Media/Newsletters/Competition-Matters/October-2020/The-Effects-of-Monopolies-are-No-Laughing-Matter (Oct. 26, 2020) (Noting that "with a monopoly, there can be little incentive for innovation or improvement on a product/service. Monopolies can also make it difficult for new and innovative companies to enter the market")..

The utility's partner, Sparkfund, occupies numerous roles typically filled by project developers who have more experience and a significant track record of success in developing projects of this scale. Conversely, Sparkfund's working relationship with Xcel has not historically resulted in the success of programs in which it provided assistance.[20] Further, C*C sets a potentially damaging precedent for treating FTM storage as a distribution asset. Viewed in full, the proposal could eliminate the competitive, third-party development necessary to realign program costs with market realities.

For these reasons, we recommend approval of Phase 2 only if the modifications we recommend below are made to reduce costs, increase benefits, and prevent ratepayers from bearing the full risk allocation of developing C*C assets.

COMMENTS

Xcel's C*C petition seeks approval for a phased program deploying 50–200 MW of front-of-the-meter, utility-owned battery systems on the distribution network. The Company describes this expansion as a means to meet system capacity needs through participation in MISO's capacity market and to support renewable integration and reliability, consistent with Commission direction in the 2024–2040 IRP.[21]

The JSP fully endorse the basic premise underlying Xcel's C*C petition: distribution-tied storage is a powerful tool that can and should become a core pillar of Minnesota's grid. The question before the Commission is not *whether* to pursue distribution-connected storage, but *how* to structure Phase 2 so that these resources are deployed at least cost, with appropriate risk allocation, and in a way that strengthens rather than weakens Minnesota's DER ecosystem.

As proposed, Phase 2 would allow the utility – working exclusively with a single commercial partner, Sparkfund – to effectively monopolize the development of 50–200 MW of distribution-connected storage inside the regulated rate base. The Company has not demonstrated that this utility self-build structure is necessary to achieve the program's technical objectives, nor that it is the most cost-effective way to do so.

The JSP file these initial comments on Xcel's proposal for the C*C program to recommend changes to program design, implementation, and operations that are necessary before approval. Our recommendations focus on the *structure* of Phase 2: who is allowed to build and own these assets, how procurement occurs, and how risk and opportunity are allocated between the utility, customers, and competitive developers.

In Summary, the JSP recommend that the Commission:

[20] Xcel Energy Response to Information Request No. 1 of the Minnesota Solar Energy Industries Association, Docket No. E002/M-25-378 (November 5, 2025) (In response to an IR, Xcel stated that "[the company] has a working history with Sparkfund through the Empower Facilities program… [which] was sunset earlier this year due to limited uptake").

[21] Xcel Energy, *In the Matter of Northern States Power Company, dba Xcel Energy, Petition for Approval of Capacity*Connect, a Distributed Capacity Procurement (DCP) program*, PETITION REQUEST FOR APPROVAL OF CAPACITY*CONNECT, Minnesota Public Utilities Commission, Docket No. E002/M-25-378, (October 3, 2025) at 4-6.

1. Direct Xcel to to redesign C*C Phase 2 around open, competitive procurement, rather than a utility self-build model, similar to recent programs adopted by Xcel's sister utility in Colorado.
2. Modify Sparkfund's role from that of an "implementation partner" in a utility self-build model to a "program administrator" or "procurement manager," tasked with designing and managing a competitive procurement process.
3. Allocate the 600 MW of remaining capacity from the original DCP concept in Xcel's IRP for third-party development, ownership, and operation, because third-party owned resources deliver comparable system benefits at significantly lower risk and cost to ratepayers.
4. Allow utility ownership of front of meter (FTM) battery energy storage systems (BESS) only when Xcel demonstrates, through a competitive solicitation, that competitive alternatives cannot meet the identified system needs at lower cost or lower risk to ratepayers.

In the alternative, should the Commission decide to move forward without the modifications recommended above, we recommend the Commission:

5. Approve only a limited version program until Xcel can produce a plan demonstrating a positive benefit-cost ratio (BCR > 1.0) and a clear, viable pathway for incorporating customer-owned and third-party systems into the program.
6. Establish guardrails to prevent utility-owned BESS from undermining DER markets, distorting interconnection, or exposing ratepayers to unnecessary financial risk. Cost recovery for the C*C should be contingent upon adherence to the approved program budget and delivering the intended ratepayer benefits, with Xcel bearing the risk for cost overruns or unrealized benefits.

If Minnesota gets the program structure right in Phase 2, C*C can mark the beginning of a new era in which distribution-tied storage becomes a core pillar of the grid and strengthens, rather than displaces, the broader DER ecosystem. We further discuss these recommendations below.

RECOMMENDATIONS

I. Accept Phase 2 of Xcel Energy's C*C program ***only if*** program modifications are made that improve the program cost-benefit ratio and protect and enhance opportunities for competitive market development

Below, we provide a number of recommendations for program modifications that we believe must be made before program approval to improve outcomes for ratepayers and protect competitive market development.

First, we recommend that the Commission approve only a modified version of the C*C Phase 2 proposal, directing Xcel to implement a revised program that focuses on competitive procurement to improve the BCR and protects competitive market opportunities for distributed energy resources. Specifically, we recommend modifying the role of Sparkfund from that of an "implementation partner" in a utility self-build model to a "program administrator" tasked with managing a competitive procurement process. Second, we recommend modifying the Phase 2 proposal to allocate the 600 MW of remaining capacity from the original DCP filing in Xcel's IRP for third-party development, ownership, and operation because private developers assume the financial risk of construction and performance rather than ratepayers.

In the alternative, should the Commission decide to move forward without the modifications recommended above, we recommend only limited approval of the program until Xcel can produce a plan demonstrating a positive cost-benefit ratio (BCR > 1.0) and a clear, viable pathway for incorporating customer-owned and third-party systems into the program. Our comments seek to highlight the success of existing non-utility-owned VPP models for customer-sited battery aggregation as a proven path forward that minimizes utility risk and maximizes customer benefits.

A. Approve a modified competitive procurement framework for Phase 2 and designate Sparkfund as a program administrator/procurement manager.

The JSP recommends modifying the role of Sparkfund in Phase 2 from "implementation partner" to a true "program administrator" tasked with with designing, implementing, and administering Phase 2 through the issuance of RFPs for the entire development-stage life cycle of the C*C Phase 2 deployment. Splitting the administrative function and development function will lead to program efficiencies by leveraging the proven track record of Minnesota's private solar and storage market.

In its October 3rd filing, Xcel proposed a phased deployment of Company-owned and -operated BESS, relying on its implementation partner, Sparkfund, to manage program design and administration, while also occupying numerous roles typically filled by project developers including site host identification, procurement of goods and services, and management of project delivery. However, Sparkfund's stated qualifications and experience purport to align with the function of a program administrator rather than project developer. Sparkfund's expertise is in "program design, engineering oversight, cost prudency, and regulatory alignment."[22] Moreover, Sparkfund states that they have extensive experience in "designing, implementing, and administering DER programs for regulated utilities and independent power producers."[23]

Solar and storage developers in Minnesota's private market possess proven qualifications and experience in site acquisition, procurement of goods and services, and managing project delivery across development milestones required for the permitting, design and engineering of FTM BESS. The competitive development market in Minnesota has successfully deployed 527 community solar projects totaling 926 MW AC since the community solar program was created in 2013.[24]

By shifting the model to a developer-led procurement under a program designed and administered by Sparkfund's oversight, the C*C program would incorporate competitive cost and value discovery across the full project lifecycle and shift the risk of cost overruns to the private market, even if Xcel

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[22] Xcel Energy Response to Information Request No. 1 of the Minnesota Solar Energy Industries Association, Docket No. E002/M-25-378 (November 5, 2025).
[23] Id.
[24] Xcel Energy, *In the Matter of Implementation of 2023 Legislative Changes to Northern States Power Co. d/b/a Xcel Energy's Community Solar Garden Program*, 2024 ANNUAL REPORT LEGACY COMMUNITY SOLAR GARDENS PROGRAM, Docket No. E002/M-13-867 (April 1, 2025) p. 2.

Energy ultimately owns Phase 2 assets. This modification would also encourage the private market to find cost-effective and integrated solutions that have the potential to lower the capital costs assumed in the Cost-Benefit Analysis (BCA) and streamline the development process.

B. Include the remaining megawatts from the original DCP concept in a competitive, third-party-owned portfolio under C*C

Xcel should structure the remaining MW from the original IRP/DCP proposal to ensure they are developed through a competitive, third-party-owned portfolio within C*C. Doing so will align the program with Commission direction, minimize ratepayer risk, and ensure that Minnesota benefits from the cost discipline and innovation that competitive markets provide. By prioritizing third-party ownership and development, and by ensuring that utility-owned assets compete on equal footing with independent developers, the Commission can secure a more affordable, transparent, and performance-driven storage portfolio for customers.

i. Third-party owned resources deliver comparable benefits at lower risk to ratepayers

Xcel's C*C petition seeks approval for a portfolio of utility-owned, FTM battery systems on the distribution grid, developed and implemented through a single commercial partner, Sparkfund. Notably, Xcel does not propose an open solicitation for ownership or development of these assets. Instead, all systems would be utility-owned and administered by Sparkfund. The proposal offers no mechanism for cost benchmarking against third-party alternatives or for piloting competitive procurement. This omission runs counter to the IRP settlement's directive to evaluate cost-benefit differences between utility and third-party ownership, and is a material deficiency in the filing that we discuss in greater detail in later comments.[25]

As written, the proposal severely restricts— and nearly eliminates—meaningful participation by distributed storage developers. Third-party roles are limited to engineering, procurement, and construction ("EPC"), described as "procurements of major equipment supply, design and engineering services, and construction and installation."[26] This excludes most traditional development workstreams, including site origination, permitting, full project design, risk management, and long-term operations.

Minnesota law and Commission precedent impose strong constraints on when utilities may expand their rate-based resource portfolios. Historically, the Commission has required all-resource competitive solicitations to determine whether a utility-owned asset is truly least-cost and least-risk, evidence-based justification for utility self-build proposals, and fair competition between utility and third-party offerings.

[25] Xcel Energy, *In the Matter of Northern States Power Company, dba Xcel Energy, Petition for Approval of Capacity*Connect, a Distributed Capacity Procurement (DCP) program*, PETITION REQUEST FOR APPROVAL OF CAPACITY*CONNECT, Minnesota Public Utilities Commission, E002/M-25-378 (October 3, 2025) p. 1-2.
[26] Id, p. 4.

C*C, as proposed, does not follow these principles. It presumes utility ownership and rate-basing as the default pathway and fails to demonstrate that third-party owned DERs cannot meet the identified capacity needs more cost-effectively.

In its proposal the Company states, "[a]nything less than full operational control and visibility of these assets – which will operate functionally as part of our system – could present safety risks for our employees and the public and could create cybersecurity risks for our system."[27]

This is in direct contradiction to the Company's statements in several other venues, including a white paper that Xcel drafted with EnergyHub and APS. Specifically, "[u]tilities and grid operations can pursue utility-led, aggregator-driven, hybrid, or dynamic pricing approaches to DER management, each offering different advantages for capturing value from grid services."[28] Given this, the statements in the Company's DCP proposal, it appears that the Company does not in fact believe full control of DERs is necessary.

Additionally, experience across the country has shown that when the regulatory framework encourages it, independent developers can rapidly and affordably supply grid services, often more efficiently than monopoly-owned assets. In Maryland, for example, HB 910 establishes a storage program that prioritizes competitive procurement and other market-based tools to meet deployment targets, signaling a clear policy preference for third-party development. While utilities can own or contract for storage resources, their role is one option within a broader framework intended to leverage third-party solutions whenever feasible.[29]

Those same risks of utility ownership are present here and include:

- **Risk of cost overruns borne by ratepayers:** Under Minnesota's regulatory model, Xcel would recover all capital costs, including overruns, through rates. This stands in contrast to third-party projects, where private capital absorbs construction risk and overruns cannot be shifted to customers. Minnesota ratepayers have already experienced the consequences of cost escalation in utility-owned infrastructure. Allowing Xcel to own a large fleet of distributed batteries without competitive procurement guardrails creates substantial exposure for customers.
- **Risk of poor performance with no accountability**: Utility-owned storage assets would be included in rates regardless of whether they deliver the expected capacity or locational benefits. Third-party resources can and routinely do accept performance obligations, with penalties or clawbacks for non-delivery. Minnesota ratepayers deserve this level of protection.
- **Risk of discouraging private DER investment:** Minnesota currently faces interconnection delays, uncertainty in upgrade cost allocation, and a backlog of projects waiting to move forward, as Xcel acknowledges in their proposal.[30] If Xcel both (1) owns and operates

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[27] Id, p. 42
[28] Smart Electric Power Alliance, *Decoding DERMS: Options for the Future of DER Management,* (March 2025), p.23. Available at https://sepapower.org/resource/decoding-derms-options-for-the-future-of-der-management/.
[29] Maryland House of Representatives, "HOUSE BILL 910," (May 8, 2023).
[30] "The vision of this program is one that provides capacity and energy benefits for customers without the need for potentially time-consuming and costly interconnection, upgrades, and investment in the bulk system, while bringing more locally stacked benefits through optimization of the distribution system." Xcel Energy, *In the Matter of*

distribution-connected storage and (2) controls interconnection timelines and upgrade decisions, competitive developers will face a structural disadvantage. This would chill the very third-party market participation that the Commission is counting on to deliver capacity, reliability, and cost savings through DERs.

- **Risk of undermining the value and viability of other Minnesota DER programs:** Minnesota is in the midst of implementing reforms to enable a more scalable DER future - including cost-sharing, proactive grid upgrades, and improved interconnection procedures. A utility-built storage fleet would directly compete with and decrease compensation for third-party DERs, including community solar + storage, aggregated DERs, and customer-sited resources. This undermines the Commission's efforts to create a vibrant DER ecosystem capable of delivering least-cost capacity and reliability services.
- **Risk of losing access to value-stacked revenue streams:** Third-party owners have the ability to capture wholesale market value in MISO, including ancillary services and capacity revenues. Utility-owned storage would not reliably return those revenues to customers, leading to a higher overall cost of service.

In light of these concerns, the Joint Solar Parties recommend establishing a clear pathway for third-party development and ownership of FTM storage assets within the Capacity*Connect program.

ii. Prioritize third-party ownership and development of storage assets

The JSP recommend revising the program to incorporate a competitive procurement framework modeled on Xcel's sister utility in Colorado.[31] Specifically we propose the following program design:

- Xcel conducts a distribution system analysis identifying feeders where C*C assets could provide distribution grid services, bulk system benefits, and locational value for ratepayers.
- The Company would then procure grid services through feeder-specific RFPs, where third-party developers can compete to build, own, and operate assets that deliver capacity, energy, and locational grid services to Xcel's distribution system and ratepayers.
- Projects bid competitively into the RFP and are evaluated using a structured avoided-cost methodology comparing each bid against generation, transmission, and distribution values based on location.
- Projects are compensated based on bid prices, ranked and selected through the avoided-cost framework. Cost-effectiveness is reported using Commission-approved avoided-cost values.
- Third-party developers retain ownership, while Xcel maintains operational control through dispatch rights and standard performance contracts.

The Company should apply this design across its full identified resource needs. The Company notes an expected additional 300 MW of standalone BESS and BESS co-located with solar resources to

*Northern States Power Company, dba Xcel Energy, Petition for Approval of Capacity*Connect, a Distributed Capacity Procurement (DCP) program*,PETITION REQUEST FOR APPROVAL OF CAPACITY*CONNECT, Minnesota Public Utilities Commission, E002/M-25-378, (October 3) 2025, p. 2.

[31] Public Service Company of Colorado, Hearing Exhibit 113, Settlement Agreement, Docket No. 25A-0194E (November 1, 2025). Available at https://www.dora.state.co.us/pls/efi/EFI.Show_Filing?p_fil=G_829309&p_session_id= .

be procured in Phase 3[32] and its 2024-2040 IRP Preferred Plan modeled 480 MW of BESS coming online in 2027.[33] These resources were previously anticipated to be competitively solicited under a Commission-approved bidding process.[34]

iii. Compete on equal footing with third-party resources

If the Commission elects to approve the Company's program structure as proposed, the JSP recommend requiring Xcel to open competitive solicitations for third-party ownership and development of the capacity expected in Phase 3 and Phase 4 of Capacity*Connect.

Given the risks outlined above and the demonstrated viability of alternative program models, the Joint Solar Parties believe the Commission should approve only proposals that prioritize third-party ownership. However, should the Commission allow utility ownership, it must ensure that utility-owned storage competes on equal footing with third-party resources.

Necessary guardrails include:

- Requiring utilities to acquire BESS assets only through competitive solicitations from third parties.
- Permitting utility ownership only where a competitive solicitation demonstrates that third-party alternatives are more costly than a traditional utility infrastructure alternative.
- Ensuring that utility-owned storage does not receive preferential treatment or distort competition through impacts on interconnection costs, queue timelines, or tariffs affecting third-party assets.

II. If the Commission approves Phase 2 without JSP's recommended modifications, the Commission should approve a limited version Phase 2 of C*C until there is a clear plan to reach a positive cost benefit ratio, expand use cases tied to system-wide value, and a viable path to incorporate third-party and customer-owned systems through an open DERMS architecture.

To ensure that C*C delivers measurable value to customers and the broader system, the Commission should require Xcel to demonstrate clear progress on the foundational elements of a viable program. This includes establishing cost-effectiveness, expanding use cases that provide systemwide benefits, and creating an open, interoperable DERMS framework that allows third-party and customer-owned resources to participate. Without these core pillars in place, the program risks proceeding without the evidence, transparency, or market integration needed to justify further investment.

A. Achieving a positive cost benefit ratio will require both cost reductions and expanded use cases tied to delivering system wide benefits.

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[32] Xcel Energy, In the Matter of Northern States Power Company, dba Xcel Energy, Petition for Approval of Capacity*Connect, a Distributed Capacity Procurement (DCP) program, PETITION REQUEST FOR APPROVAL OF CAPACITY*CONNECT, Minnesota Public Utilities Commission, Docket No. E002/M-25-378 (October 3, 2025) at 9.
[33] Id, at 100.
[34] Id.

As proposed, the C*C does not provide system benefits sufficient to support cost-effectiveness. The BCA, conducted "under a single, ambitious scenario" and modeled using "optimistic underlying assumptions, and aggressive cost reductions"[35] resulted in a BCR of .96 for a 200 MW deployment.[36] Additional quantifiable benefits will make the program more cost effective. The JSP recommend the Commission approve only a modified proposal that captures additional system benefits derived from flexible interconnection and flexible energization use cases, and expanded use of Grid DERMS by third party owners.

B. System wide benefits could be expanded by developing additional use cases for C*C assets focused on relieving grid congestion in constrained areas.

The budget for C*C includes the budget for a Grid DERMS deployment for three initial use cases: flexible interconnection, flexible energization, and C*C.[37] However, the October 3rd filing and discovery made clear that Xcel does not intend to enable the hosting capacity benefits derived from flexible interconnection and flexible energization with Phase 2 investments. The program proposal states that Phase 2 of the C*C is designed to "support bulk system needs in the near term, so any impact to distributed generation (DG) hosting capacity would be incidental." In response to discovery, Xcel stated that in certain use cases, C*C could accelerate the connection of new generation or new load.[38] In the future "[g]rid congestion relief is one of many potential use cases" for the C*C program and C*C assets could be "dispatched specifically to relieve grid congestion for new load or distributed generation, or to address voltage issues."[39]

C*C assets, including both the BESS and the Grid DERMS, can be used to increase DG hosting capacity. C*C BESS may be used to relieve grid congestion for new load or distributed generation by raising the DML or providing voltage support. Grid DERMS may be used to increase DG hosting capacity by enabling flexible interconnection. While flexible interconnection benefits will flow to third parties, enabling this system benefit could result in lower bids for future rounds of the DSES program, which the utility is required by statute to fulfill, and thus provide system wide benefits.

Modifying the program to capture additional system benefits derived from flexible interconnection and flexible energization will introduce additional, quantifiable stacked benefits to the program and incentivize Xcel to gain experience operationalizing the trade-offs between specific benefit tradeoffs.

[35] Id, at 34.
[36] Id, at 35.
[37] Id, at 31.
[38] Xcel Energy Response to Information Request No. 2 of the Minnesota Solar Energy Industries Association, Docket No. E002/M-25-378 (November 5, 2025).
[39] Xcel Energy Response to Information Request No. 4 of the Minnesota Solar Energy Industries Association, Docket No. E002/M-25-378 (November 5, 2025).

C. System wide benefits could be expanded by expanding the use of the Grid DERMS to provide access to third party and customer owned systems.

Xcel Energy's assertion that a Distributed Energy Resource Management System (DERMS) is required for Phase 2 of Capacity1Connect (CC) is not supported by the structure and objectives of the program as filed. Phase 2 is explicitly focused on small-scale deployment of front-of-the-meter batteries operated for bulk-system benefits such as MISO capacity and energy market participation—not distribution-level optimization. A DERMS platform is unnecessary to achieve these Phase 2 use cases. Moreover, Xcel's proposal places the burden of a $2.9 million "limited Grid DERMS" on Minnesota ratepayers even though the filing acknowledges: "The costs for future DERMS software capabilities and investments in people, processes, and organizational structure are not included in the CC Phase 2 budget."* This open-ended cost exposure is inappropriate and imprudent absent a clear, distribution-level operational need.

Xcel also concedes that the cost of a full, enterprise DERMS is unknown in Minnesota, stating: "Those costs are not known currently…" Yet in Colorado, the same company has already developed detailed cost expectations through a comprehensive DERMS procurement process. There, Xcel found that an aggregator DERMS would likely cost "in the low millions," while a fully integrated grid DERMS would be "in the tens of millions of dollars." Xcel issued an RFP to seven vendors after evaluating 32 companies and developing over 100 use cases and more than 1,000 functional requirements. These learnings—already funded by Colorado customers—should be applied in Minnesota before the Commission authorizes new DERMS expenditures. Minnesota ratepayers should not be asked to finance duplicative discovery, software procurement, or organizational restructuring work that Xcel has already undertaken elsewhere.

Importantly, the Joint Solar Parties (JSP) are not opposed to DERMS development in principle. A DERMS platform may ultimately be appropriate for longer-term, distribution-level use cases such as relieving grid congestion in constrained areas, supporting non-wires alternatives, and delivering equity-enhancing system benefits. However, because Xcel's current proposal does not articulate or commit to these use cases—and instead centers almost exclusively on utility-owned batteries providing bulk-system services—the JSP recommend that if the Commission approves Phase 2 without the modifications proposed herein, it should authorize only a limited Phase 2 until Xcel provides: (1) a clear plan to reach a positive cost-benefit ratio, (2) expanded use cases tied to system-wide value, and (3) a viable path to incorporate third-party and customer-owned systems through an open DERMS architecture.

Finally, Xcel's Colorado proceeding offers an important governance lesson for Minnesota. There, the Commission found broad stakeholder agreement that DERMS should support an open-market model in which the utility functions as a buyer of services, DER aggregators as sellers, and the DERMS provider as a neutral market platform enabling transactions.[40] This stands in sharp contrast to Xcel's Minnesota proposal, which would consolidate DERMS functionality inside a utility-controlled operational system and limit participation to company-owned assets. To ensure competition, innovation, and ratepayer value,

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[40] PUC of Colorado, RECOMMENDED DECISION OF HEARING COMMISSIONER TOM PLANT ISSUING CERTAIN GUIDANCE FOR REQUESTS FOR PROPOSALS TO BE ISSUED BY PUBLIC SERVICE COMPANY OF COLORADO, PROCEEDING NO. 23M-0466EG (January 5, 2023)

the Commission should direct Xcel to adopt the Colorado model and enable open access to third-party and customer-owned systems before any DERMS investment is approved.

III. Xcel should be required to refile its proposal to include the comparative analysis of customer-sited battery aggregations that the Commission directed it to provide in the DCP filing and that the Company failed to include in its submission

Commission consideration of the Company's DCP Proposal was not intended to occur in an information vacuum. As the Commission directed in Order Point No. 23 in the IRP Order, the Company was required to include in its DCP proposal "an evaluation of costs and benefits comparison between a utility-owned and managed DCP model and alternative models allowing participation from customer-owned and third party-owned resources."[41] Despite the directive, the Company's proposal did not include a meaningful description of what a non-utility version of the DCP model might look like, much less a comparison of the costs and benefits of such a model against the C*C proposal, and made unfounded claims that the private market was unable to deploy batteries at scale safely. This is a material deficiency in the Petition that should be cured before the Commission concludes its consideration and issues a final disposition.

For purposes of comparing Phase 2 of the C*C proposal to any of the available non-utility models for customer-sited battery aggregation, the JSP recommend that the Commission consider the most commonly used "pay for performance" model that compensates participating battery storage devices based on actual measured performance, helping protect nonparticipating ratepayers from paying for more value that they receive.[42] Like Phase 2 of the C*C Proposal, the pay-for-performance model focuses on bulk system peak reduction (e.g., capacity) but could also can (and has) been evolved to address locational system constraints.

ConnectedSolutions is one of over a dozen programs across the country that utilize non-utility models for customer-sited battery aggregation.[43] Although ConnectedSolutions is a retail program that is not directly integrated into the wholesale market, it is market reflective and proven to be a cost-effective program. State commissions in Illinois, Maryland, Virginia, North Carolina, Hawaii, Colorado, California, Arizona, Georgia, Texas, Connecticut, and Rhode Island, among others, have all begun consideration or have fully adopted some form of retail pay-for-performance program model. These programs typically exclude utility ownership of behind-the-meter battery assets.[44]

Even in a later phase or in a future iteration of Phase 2, these retail programs would offer some benchmark of how non-utility-owned, customer-sited behind-the-meter batteries can reduce locational

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[41] Xcel Energy, In the Matter of Northern States Power Company, dba Xcel Energy, Petition for Approval of Capacity*Connect, a Distributed Capacity Procurement (DCP) program, PETITION REQUEST FOR APPROVAL OF CAPACITY*CONNECT, Minnesota Public Utilities Commission, Docket No. E002/M-25-378 (October 3, 2025) at 5

[42] "Pay for performance" VPPs are most often compared to the ConnectedSolutions programs offered by the electric distribution companies in Massachusetts. Details on ConnectedSolutions and all other customer-sited, BTM battery programs are included in the attached "JSP Appendix A."

[43] Id.

[44] Programs that utilize customer-sited, utility-owned assets are detailed in the attached "JSP Appendix B."

constraints on the distribution system at a cost benefit to ratepayers. Siting and utilizing batteries on high-value portions of the grid does not require utility-ownership of those assets, it simply requires that the information be made available or be incorporated into the program design.

A number of battery aggregation pilots and programs targeting local constraints are already operating. In Massachusetts, ConnectedSolutions has begun a locational adder for projects on specified feeders.[45] In California, Pacific Gas & Electric is engaged in a bilateral program with a solar+storage developer to locationally target constrained feeders.[46] In New York, PSEG-LI provides a locational value "adder" of 50% that can be stacked onto performance payments in areas surrounding 13 more congested feeders of their distribution system.[47] The Connecticut Energy Storage Solutions Program provides a "Grid Edge Adder" for customer-sited energy storage projects that are located on parts of the grid that face more frequent and lengthy power outages, while also providing locational adders for projects developed in underserved communities to increase program equity.[48] Illinois also recently passed legislation, the Clean Reliable Grid Act, that directs the Illinois Commerce Commission to provide an adder for distributed resources in underserved communities and at the grid edge when enrolled in a virtual power plant pay for performance program.[49]

It is, thus, inaccurate and insufficient for the Company to claim, in a cursory manner, that non-utility-owned, customer-sited resources are not valuable or as valuable as the limited scale deployment and use case contemplated in Phase 2 of the C*C Proposal.[50]

Just as battery sites are being prioritized on feeders with coincidence to bulk system peak demand through the C*C Program, it is easy to contemplate how a pay-for-performance model could yield similar benefits or data, with or without information or specific values provided for targeting desired feeders. As penetration of BTM batteries increases, even if sited in a scattershot approach, there will be batteries that are naturally located on feeders with some coincidence to bulk system peak demand. Operation of these assets to serve coincident peak demand, thus, will provide similar benefit as Company-owned assets for each electron dispatched during the peak windows. Information on utility- and non-utility performance and contribution to local peak reductions could be informative in considering the most cost-effective and timely way to scale up locational solutions. Additionally, the ease of customer uptake under the various models would also be informative as to how well each model can be leveraged to target locational values and other, future locational use cases.

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[45] https://www.nationalgridus.com/ConnectedSolutionsPlus

[46] Pacific Gas & Electric, *"PG&E Launches Seasonal Aggregation of Versatile Energy (SAVE) Virtual Power Plant Program"* (March 2025), available at https://investor.pgecorp.com/news-events/press-releases/press-release-details/2025/PGE-Launches-Seasonal-Aggregation-of-Versatile-Energy-SAVE-Virtual-Power-Plant-Program/default.aspx.

[47] PSEG-LI, "*Utility 2.0 Long Range Plan 2018 Annual Update*" (June 2018)

[48] See the Connecticut Energy Storage Solutions Program Manual, pgs. 10 and 44, available at ahttps://energystoragect.com/wp-content/uploads/2025/01/ESS-Program-Manual-01172025-Clean-FINAL.pdf

[49] Illinois: Senate Bill 25, 2025. Passed legislature on 11/25/25

[50] Xcel Energy, In the Matter of Northern States Power Company, dba Xcel Energy, Petition for Approval of Capacity*Connect, a Distributed Capacity Procurement (DCP) program, PETITION REQUEST FOR APPROVAL OF CAPACITY*CONNECT, Minnesota Public Utilities Commission, Docket No. E002/M-25-378, (October 3, 2025) at 43 (claiming that resources fully controlled by the Company will achieve "broader system benefits more efficiently").

The Company asserts that realizing the full value of these assets requires that they have "...strategic deployment in target locations, coordinated control and dispatch, and total visibility…"[51] and that other ownership structures could only provide a portion of the expected value. The Proposal does not quantify what portion of value incorporated into the BCA could be provided through alternative ownership structures nor whether the costs associated with alternative approaches would also be lower. The C*C Proposal would force ratepayers to bear the full cost of deploying energy storage and also bear the risk of non-performance, with success of the C*C Proposal, in the unlikely chance that it can meet the "ambitious" assumptions used in the BCA, still being a result that is not cost-effective for ratepayers. Even if it is granted that utility-ownership and control *may* provide some incremental value, it is not clear that the costs associated with that incremental value are worthwhile. A program that may provide lower value but does so at a much lower cost, and with performance risk being borne by third-parties rather than captive ratepayers, may very well have a BCA that exceeds that of the C*C Proposal.

At a minimum, the Commission should not approve the Company's C*C Proposal without due consideration of the alternatives, particularly given the explicit request to have a comparative evaluation of these approaches included as part of the Company's filing. The JSP welcomes the opportunity to work with the Company to frame and conduct the required analysis to give a fair representation to the alternative pathways and cure the informational deficiency that should prevent Commission approval of the petition.

IV. Discussion of Specific Implementation Topics Open for Comment

The Commission has identified several specific implementation topics for stakeholder input, and the JSP provide comments on each of these areas below. These topics include the delivery of system benefits, ensuring that C*C assets provide measurable value to the grid; reporting requirements, to promote transparency and accountability; the program budget, including long-term cost projections; the procurement process, to ensure fairness and competitive outcomes; the applicability of interconnection standards under the Minnesota Distributed Energy Resources Interconnection Process (MN DIP), to maintain an equitable queue for all DER projects; and cost recovery mechanisms, to protect ratepayers and ensure that only appropriately justified costs are recoverable. Addressing these topics thoughtfully is critical to designing a program that delivers benefits, manages risk, and supports Minnesota's DER ecosystem.

A. Delivery of System Benefits

The JSP provides no additional comments on the delivery of system benefits beyond the recommendation above to approve only a modified proposal that captures additional system benefits derived from flexible interconnection and flexible energization use cases, and expanded use of Grid DERMS by third party owners. We reserve the opportunity to provide additional comments in reply and supplemental comments.

[51] Xcel Energy, In the Matter of Northern States Power Company, dba Xcel Energy, Petition for Approval of Capacity*Connect, a Distributed Capacity Procurement (DCP) program, PETITION REQUEST FOR APPROVAL OF CAPACITY*CONNECT, Minnesota Public Utilities Commission, Docket No. E002/M-25-378, (October 3, 2025) at 41

B. Reporting

The JSP provides no additional comments on reporting. We reserve the opportunity to provide additional comments in reply and supplemental comments.

C. Budget

The estimated program budget for Phase 2 is $152 million to $430 million for a 50 MW up to a 200 MW deployment through 2028. It is the JSP's perspective that these program costs are unreasonable.

C*C has an estimated budget of $2,150 per kW for 200 MW of BESS Deployment, whereas Xcel's AVPP program in Colorado will cost an estimated $624 per kW for 125 MW.[52] A primary reason that C*C is 244% more expensive than the AVPP program is that C*C includes the BESS Capital Costs required for Xcel ownership. Under a pay for performance model, which is explained in more detail above, instead of all ratepayers paying for BESS Capital Costs on their bills, private market capital is leveraged by customers who allow the utility to use their home batteries in exchange for incentives. The JSP recommend the Commission consider whether budgetary reductions in program costs could be achieved by merely offering participation incentives to third party owners and developers, which is significantly less expensive than the utility investing in new BESS assets.

Second, if Xcel considers C*C BESS as 20 year assets, a three-year budget does not provide the Commission with a complete record to determine whether or not these costs are reasonable in the short or long-term. BESS Equipment Operations and Maintenance costs will continue for the 20-year life of the BESS, but the budget only reflects O&M costs through the anticipated Phase 2 deployment period (2026-2028). Host site payments will be made per site per month over the 20-year life of the BESS, for 200 sites, but the only budget reflects site host payments through 2028. The budgetary information provided by Xcel provides an incomplete record of the program budget.

D. Procurement process

The JSP provides no additional comments on the procurement process beyond the recommendation to modify the program to place Sparkfund in the role of a "procurement manager" that administers RFPs for the full life cycle of development, from host site identification to operations and maintenance of C*C assets. We reserve the opportunity to provide additional comments in reply and supplemental comments.

E. Applicability of MN DIP

The JSP Recommend that the Commission deny Xcel's proposal to interconnect C*C assets while bypassing the MN DIP interconnection queue. The October 3rd filing claimed that C*C assets that are

[52] Public Service Company of Colorado, Hearing Exhibit 113, Settlement Agreement, Docket No. 25A-0194E (November 1, 2025).

"FTM, utility-owned and -controlled, dispatchable DER, strategically deployed to serve as bulk system assets that are not functionally different from the Company's distribution system" are not contemplated by the MN DIP.[53] The proposal concludes that while the utility will perform MN DIP system studies, "C*C assets akin to bulk system resources are not subject to MN DIP."[54]

The integrity of the MN DIP process, which has been carefully developed and continuously modernized and managed by the Commission and other stakeholders through rulemaking and other regulatory proceedings, must be protected. The Commission established the MN DIP process to fulfill its statutory charge under Minn. Stat. § 216B.1611 to set statewide standards for the interconnection and parallel operation of DER of no more than 10 megawatts (MW) per interconnection application, and continues to revise and craft new standards to meet the needs of the evolving distribution system. Allowing C*C assets to interconnect and claim hosting capacity while skipping the MN DIP interconnection queue will provide Xcel an unfair competitive advantage that will degrade the integrity of MN DIP and diminish the Commission's regulatory authority over DER interconnection.

MN DIP 1.1.1 clearly states that the MN DIP process "applies to any Distributed Energy Resource (DER) no larger than 10 MW interconnecting to, and operating in parallel with, an Area EPS distribution system in Minnesota."[55] MN DIP defines "Distributed Energy Resource" as "[A] source of electric power that is not directly connected to a bulk power system. DER includes both generators and energy storage technologies capable of exporting active power to an EPS" .[56] The definition of "Interconnection Customer" is "The person or entity, including the Area EPS Operator, whom will be the owner of the DER that proposes to interconnect a DER(s) with the Area EPS Operator's Distribution System."[57]

Nothing in the MN DIP states that FTM utility-owned and -controlled, dispatchable DERs should be exempted. C*C assets are DERs sized under 10MW that will be interconnected to the distribution system and not the bulk power system. Xcel as the Area EPS operator is explicitly incorporated in MN DIP as an interconnection customer. Therefore, C*C asserts fall fully within the jurisdiction of the MN DIP and the Commission's authority over statewide interconnection processes.

The petition provides that Xcel's "intention is to not deploy C*C assets that would trigger significant upgrades to accommodate addition of these assets, as one of the key benefits of this approach is to accelerate speed to incremental capacity of these systems."[58] When, not if, C*C projects trigger upgrades at constrained locations with long interconnection queues, disputes will inevitably arise. In an

[53] Xcel Energy, In the Matter of Northern States Power Company, dba Xcel Energy, Petition for Approval of Capacity*Connect, a Distributed Capacity Procurement (DCP) program, PETITION REQUEST FOR APPROVAL OF CAPACITY*CONNECT, Minnesota Public Utilities Commission, Docket No. E002/M-25-378 (October 3, 2025) at 18

[54] Id.

[55] State of Minnesota, Distributed Energy Resources Interconnection Process, p. 2.

[56] Id, at 23.

[57] Id.

[58] Xcel Energy, In the Matter of Northern States Power Company, dba Xcel Energy, Petition for Approval of Capacity*Connect, a Distributed Capacity Procurement (DCP) program, PETITION REQUEST FOR APPROVAL OF CAPACITY*CONNECT, Minnesota Public Utilities Commission, Docket No. E002/M-25-378 (October 3, 2025) at 18.

effort to prevent future disputes and propose solutions that work for all parties, we recommend modifying the MN DIP to allow C*C projects to be excluded from the MN DIP if the C*C interconnection utilizes hosting capacity reserved by Xcel's Technical Planning Standard (TPS).

> Add Section 1.1.8: The MN DIP does not apply to any DER owned or controlled by an Area EPS Operator that has an Export Capacity of 10 MWs or less and does not exceed [X%]of the maximum capacity of the applicable substation/feeder, excluding any capacity limitation/standard imposed by the Area EPS Operator.

With this proposed modification, Xcel may exclude C*C projects if it treats the capacity reserved for its TPS as available hosting capacity for the interconnection of its company owned and operated C*C projects. Excluding utility owned C*C projects that are interconnected within the hosting capacity reserve made available by the TPS necessarily means that the MN DIP applies to all interconnection applications that are not excluded, regardless of the identity of the interconnection customer. In other words the MN DIP would continue to apply to all interconnections that utilize up to 80% of the systems rated hosting capacity.

If the Commission determines that MN DIP does not apply to C*C assets we respectfully request that the commission address interconnection concerns created by bypassing the queue; guardrails are needed to prevent disputes and protect the integrity of the MN DIP process. We recommend the commission modify the program proposal to require that:

- C*C assets used for bulk system dispatch may not be sited in locations with low hosting capacity [less than 50% of available capacity remaining].
- C*C assets may not be sited in locations where there are more than 500 kW of DG in the interconnection queue.
- C*C assets may not be sited in locations with proactive/reactive upgrade zones unless Xcel covers its fair, pro-rata share of upgrade costs.

F. Cost recovery

In its October 3rd filing Xcel requested Commission approval for recovery of costs associated with the C*C program – beginning with Phase 2-specific costs that are separate and incremental to Phase 1 – through the RES Rider, pursuant to Minn. Stat. § 216B.1645.[59]

Minn. Stat. § 216B.1645, subd. 1 authorizes the Commission to "approve or disapprove power purchase contracts, investments, or expenditures entered into or made by the utility to satisfy... the renewable energy objectives and standards set forth in section 216B.1691."[60] Specifically, the statute

[59] Id, at 50.
[60] The relevant renewable energy objectives and standards are the Eligible Energy Technology Standard at Minn. Stat. § 216B.1691, Subd. 2a., the Solar Energy Standard at Minn. Stat. § 216B.1691, Subd. 2f., the Carbon Free Standard at Minn. Stat. § 216B.1691, Subd. 2g. and the Distributed Solar Energy Standard at Minn. Stat. § 216B.1691, subd. 2h

authorizes approval of reasonable investments if they "provide storage facilities for renewable energy generation facilities that contribute to the reliability, efficiency, or cost-effectiveness of renewable facilities."[61] Further, Minn. Stat. § 216B.1645, subd. 2a(3) permits cost recovery of qualifying renewable energy projects including "expenses incurred that are directly related to a renewable energy project, including expenses for energy storage," provided the utility demonstrates that they "improve project economics, ensure project implementation, advance research and understanding of how storage devices may improve renewable energy projects."

C*C costs are not aligned with the statutory intent for cost recovery under the RES Rider because C*C assets will not be "directly associated with a renewable energy project" but rather used to store and discharge energy from non-renewable resources. The C*C program will not deploy solar or co-locate C*C assets with renewable projects. C*C BESS "will charge from the grid with varying costs and levels of emissions, but.. not directly emit carbon or other greenhouse gases when discharging." Ostensibly, without the presence of co-located solar and relying on grid power to charge, C*C assets will indirectly emit carbon and other greenhouse gases, and fail to meet the renewable energy objectives and standards set forth in section 216B.1691.

Energy arbitrage using non-renewable resources will not "advance research and understanding of how storage devices may improve renewable energy projects." While energy storage pilots have been allowed in the past, Phase 2 is not pilot. For these reasons, statutory recovery through the RES rider is inappropriate, and the JSP recommend the Commission modify Xcel's request to approve cost recovery through the RES only if C*C assets are directly associated with a source of carbon free generation.

V. Additional Concerns

A. Equity

First, the Cost-Benefit Analysis for C*C Phase 2 indicates that quantifiable costs are likely to exceed quantifiable benefits. This carries a risk of increasing costs for all ratepayers, which will equitably have the greatest impact on those who have issues affording their electricity bills because universal increase in rates generally impacts customers with affordability issues more significantly than others.

Additionally, it should be noted that as written, the C*C proposal does not help with reliability to keep power on during grid outages in the communities that are planned to host these batteries. Grid outages are especially acute in underserved communities, as this Commission has found previously.[62] Specifically, there are racial and income disparities in electricity reliability here in Minnesota. Dr. Garbriel Chan, from the University of Minnesota, found that in both the northside and southside of Minneapolis—areas with more low-income people and communities where a larger percentage of the population are communities of color—have higher rates of long-duration power outages than other Xcel customers in Hennepin County (between 59% and 85% increased incidence) and in Xcel's overall service territory (between 32% and 35% increased incidence).[63]

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[61] Minn. Stat. § 216B.1645, subd. 1(2)
[62] Minnesota Public Utilities Commission Docket No. E002/GR-21-630; Exhibit JSC-6 at 21.
[63] Ibid.

As previously mentioned, in Connecticut, Illinois, and on Long Island, New York, utilities have developed incentive "adders" in specific geographic locations that are designed to best serve the community from a grid congestion perspective. If communities in both northern and southern Minneapolis consistently experience more frequent and longer grid outages than others throughout Hennepin County, the Commission should consider pushing Xcel to establish "adders" for batteries in those areas that can be used during blackouts that provide resilience benefits for those specific communities. To restate, the C*C program does not provide localized resilience benefits.

The vast majority of customer-sited batteries are installed as part of an integrated solar+storage system that can optimize usage and achieve cost savings in response to rate designs, provide resilience for the customer when the grid is down, and provide services to the grid when there is an explicit program to provide price signals that support turning this private investment toward a public benefit. The existence of grid services compensation can help further encourage customer decisions to pair solar with onsite battery storage, beyond the existing consumer trends. If opportunities to utilize batteries to generate additional revenue exist, more consumers will be able to access a behind-the-meter battery, setting off a virtuous cycle of private investment to support a public good.

In Minnesota, these trends are lagging the national average. This is, in part, due to restrictions on third-party ownership of behind-the-meter assets. With the elimination of the federal 25D tax credit, third-party financed solar+storage will be the only method for the next several years for customers to capture federal tax benefits that will help bring down the costs of installing and using these assets. This issue is beyond the scope of this proceeding but is raised here for visibility into the larger policy scheme in Minnesota that will need adjustment to truly optimize and unlock the potential of customer-sited, non-utility battery storage. To the extent that meaningful grid services compensation existed in Minnesota, this would provide an expected lift to the installation of solar+storage devices and provide additional resources to the grid at a fraction of the cost of the Company's C*C Program.

CONCLUSION

The JSP applaud the C*C proposal from Xcel and appreciate the thoughtful engagement from stakeholders regarding the details of the program. The JSP are grateful for the opportunity to provide these initial comments and recommendations. Minnesota is at an important inflection point in shaping how distributed energy resources, storage, and emerging virtual power plant models are integrated into the grid. The decisions made in this proceeding will set precedent not only for C*C, but for the broader role that DERs will play in delivering reliability, affordability, and consumer value across the state and the nation.

As detailed throughout these comments, the JSP believe that Xcel's proposal—while conceptually aligned with Minnesota's clean energy objectives—requires significant modification to ensure that it is cost-effective, market-aligned, and structured in a way that encourages innovation rather than dampening it. Competitive procurement, meaningful opportunities for third-party ownership and development, and open-architecture DERMS design are foundational principles of successful VPP and distributed storage programs nationwide. These elements reduce risk to ratepayers, enhance system benefits, and rely on the proven strengths of Minnesota's private market. Incorporating these principles into Phase 2 of C*C is essential for ensuring that the program delivers on its promises.

If the Commission elects to proceed without adopting these modifications, the JSP recommend approving only a limited Phase 2 until a clear path exists to achieve a positive benefit-cost ratio, expand use cases tied to real system needs, and incorporate customer- and third-party-owned resources. Doing so will protect Minnesota ratepayers and maintain the integrity of the state's competitive DER market.

Finally, the JSP reiterate our commitment to continued collaboration with the Commission, the Department of Commerce, the Attorney General, Xcel Energy, Sparkfund and all stakeholders. We appreciate the constructive discussions to date and stand ready to assist in developing a program framework that aligns Minnesota's reliability goals, cost-effectiveness requirements, and clean energy ambitions. With the right design choices, Minnesota can deploy DERs at scale in a way that strengthens the grid, protects customers, and supports an innovative, competitive, and equitable clean energy marketplace.

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