May 11, 2026

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

Re: In the Matter of a Commission Investigation on Grid and Customer Security Issues Related to Public Display or Access to Electric Distribution Grid Data, Docket Number E-999/CI-20-800

Executive Secretary Bergman,

The Minnesota Solar Energy Industries Association ("MnSEIA"), and United States Solar Corporation ("US Solar") (herein, Joint Parties) respectfully submit these Reply Comments in regard to the Commission's March 31 Notice of Comment Period seeking input on the Grid Data Sharing Framework Report ("Draft Framework" or "Framework") submitted on March 4, 2026, in Docket 20-800, and the initial comments submitted on April 30, 2026.

Sincerely,

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PUBLIC UTILITIES COMMISSION

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In the Matter of a Commission Investigation on Grid and Customer Security Issues Related to Public Display or Access to Electric Distribution Grid Data.

REPLY COMMENTS OF THE JOINT PARTIES

May 11, 2026

Docket No. E002/M-20-800

The Joint Parties appreciate the extensive stakeholder engagement reflected in the Draft Framework, and in initial comments in this docket. We support the establishment of a statewide framework that will provide clarity, consistency, and appropriate safeguards for sharing distribution grid data. However, we continue to have concerns regarding how the Draft Framework should function in practice and recommend modifications. At its core, our concerns are not whether to adopt a framework, but ensuring that framework will enable rather than impede access to the data necessary for distributed energy resource (DER) development. The Joint Parties strongly concur with the Department of Commerce, that:[1]

> "[T]he state's ability to meet its policy objectives regarding clean energy deployment, such as the 2040 carbon-free standard, the Distributed Solar Energy Standard (DSES), or the community solar garden (CSG) program, among others, is heavily impacted by decisions regarding data access." As distribution planning undergoes an exponential increase in the sheer volume of data required to efficiently plan and operate the distribution

[1] Department of Commerce, Initial Comments, at 4

> system, it is more critical than ever that market participants and project developers maintain equitable access to the data required for cost-efficient and safe realization of Minnesota's clean energy goals.

As currently structured, the Draft Framework risks imposing overly burdensome, non-differentiated requirements that will delay projects, increase costs, and undermine Minnesota's clean energy goals. Our Reply Comments here provide further detail on the need to clarify the assignment of risk and reduce discretion in data scope, and clearly define grid data process timelines.

I. The Framework Should Adopt a Proportional, Risk-Based Process

The most significant issue in the current Draft Framework is the failure to meaningfully differentiate between low-, medium-, and high-risk data in its procedural requirements. The Joint Parties continue to respectfully argue that uniform measures, such as requiring background checks and scoping meetings for even the most basic data requests is inconsistent with the framework's risk-tiering principles and could create unnecessary friction for routine data requests.

For context, the Federal Electric Regulatory Commission (FERC) already gives developers access to critical energy infrastructure information (CEII) at the transmission level, as long as the requesting entity registers, completes an NDA, and provides a legitimate purpose for the request[2]. Without improvements, this Draft Framework could in practice prove more burdensome than FERC's approach – even regarding non-CEII data, inadvertently tilting the playing field in favor of utility-developed infrastructure.

[2] https://www.ferc.gov/ceii

At a high level, Joint Parties continue to recommend a tiered, risk-based process in which[3]:

- Low-risk data is accessible through streamlined processes;
- Medium-risk data is subject to moderate safeguards;
- High-risk data is subject to full review and all necessary controls.

II. Unchecked Subjective Utility Discretion Should Be Replaced with Clear Standards

In initial comments, multiple utility commenters emphasized that they need broad discretion to approve, deny, or revoke data access depending on the request and the requestor.[4] While some discretion is appropriate, the current framework provides insufficient guardrails and detail, creating risks of inconsistent and overly restrictive decision-making. As an example of the broad jurisdiction utilities seek to claim, Dakota Electric plans to not adopt the framework, and proceed in their own jurisdiction with a previously approved process.[5] If the Framework is meant to standardize grid data access, then it needs to be fully adopted and iterated upon by all parties, not leveraged in part when it benefits a utility or a requestor, and ignored in other cases.

The Joint Parties recommend that the Commission should thus modify the Draft Framework and/or continue proceedings to clarify and establish the following elements:

- Consistent, objective criteria for risk classification;
- Clear standards for approving or denying requests; and

[3] Joint Parties Initial Comments, at 8-10
[4] *See* Minnesota Power Comments, at 6; Xcel Energy Comments, at 2.
[5] Dakota Electric Comments, at 3.

- Transparent and reviewable decision-making processes.

These requirements and process consistency can and should be evaluated as the Draft Framework is implemented. The Joint Parties reiterate the need for robust evaluation and ongoing oversight of the Framework. We continue to recommend expanding the annual compliance filing metrics to include granular detail on data processing times, approval rates, and appeals outcomes, broken down by risk level and topic area. Crucially, we continue to propose implementing a **30-day negative check-off period** upon receipt of each utility's annual compliance filing. This mechanism would allow interested parties to file comments in response to these annual compliance filings if needed, and trigger an earlier, comprehensive review of the Framework's efficacy. So doing would supplement the proposed three-year review timeline, and continue to improve the Draft Framework.

III. Timelines Should Provide Predictability and Stable Outcomes.

In initial comments, multiple utilities argued for timelines to be flexible at the utility's jurisdiction, rather than binding requirements.[6] However, the absence of defined timelines will result in delays and uncertainty. As we noted in our initial comments, the MN DIP, which the grid data request process would logically mirror, provides a useful reference point of the sorts of concrete timelines necessary:[7]

> "5.2.2 The Area EPS Operator shall make Reasonable Efforts to meet all time frames provided in these procedures. If the Area EPS Operator cannot meet a deadline provided herein, it must notify the Interconnection Customer in writing within three (3) Business Days after the deadline to explain the reason for the failure to meet the deadline, and provide an estimated time by which it will complete the applicable interconnection procedure in the process.

[6] *See* Minnesota Power Comments, at 3; Xcel Energy Comments, at 2.
[7] *See* MN DIP 5.2, at p. 23.

> 5.2.3 For applicable time frames described in these procedures, the Interconnection Customer may request in writing one extension equivalent to half of the time originally allotted (e.g., ten (10) Business Day for a twenty (20) Business Days original time frame) which the Area EPS Operator may not unreasonably refuse. No further extensions for the applicable time frame shall be granted absent a Force Majeure Event or other similarly extraordinary circumstances."

It would be unreasonable to accede to lesser requirements or rigor, in pursuit of a centralized, standardized framework for data access. Universal and unlimited flexibility in completing requests is unreasonable, and could act as a barrier to the development of renewable resources, by adding delay, uncertainty, and cost to the siting of those resources. Additionally, concrete and well-developed timelines for the grid data request process will increase procedural ease. Uncertain timelines and undue gaps in request processing will inevitably increase the number of disputes that make their way through a potential Grid Security Working Group process, or formal complaints that are filed with the Commission itself.

For these reasons, the Joint Parties continue to support:

- The establishment of clear, fixed timelines for each stage of the request process;
- Guidelines for altering timelines only with limits and clear communication, such as provided in MN DIP (above) or the California proceeding illustrated in the Joint Parties' initial comments[8];
- Requirements for timely communication and updates from both requestors and utilities as needed.

[8] *See* Joint Parties Initial Comments, at p. 16-18

IV. The Framework Should Clearly Define the Scope of Data Types Covered

The Draft Framework does not at present clearly define permissible data categories. This lack of clarity will lead to disputes and inconsistent outcomes. As indicated in our initial comments, while the framework provides examples in each risk category, and provides limited justification for each category, it does not provide firm or exhaustive definitions, or lists of data that applies to each risk category.

The Joint Parties are not the only commenters with concerns about the lack of definitive parameters. In initial comments, Xcel Energy noted that "The current Report does not specify which data can be requested and how that ties to legitimate uses pertaining to siting DER. Without these parameters, overly broad or inappropriate requests will strain the request and dispute resolution processes. This issue must be addressed before a workable Framework is established."[9]

To this, the Joint Parties would add a second concern – that the lack of clear categories could result in overly prohibitive risk classifications, or overly restrictive responses to data requests. However, regardless of what concern a party has, it is clear that greater clarity on the types of data that falls into each category will assist all parties in the development of a successful framework.

a) The Framework Should Allow Access to the Data Types Listed in the Commission's July 2, 2024 Notice of Workgroup in this Proceeding

The Commission has already considered some of the needed data types for DER development. The Commission's July 2, 2024 Notice of Workgroup in this proceeding included the following list of relevant types of grid data:

[9] Xcel Energy, Initial Comments, at 3.

ATTACHMENT 1[10]

1. Distribution grid map with critical energy infrastructure
2. Distribution grid map with critical infrastructure
3. Distribution grid map at feeder level
4. Distribution grid map at secondary level
5. Distribution grid map at customer meter level
6. By Substation
    a. Forecasted Annual Peak Load
    b. Actual Annual Peak Load
    c. Actual Daytime Minimum Load
    d. Load shapes (seasonal)
    e. Load shapes (hourly)
    f. Hosting Capacity Results (min. and max)
    g. Hosting Capacity Criteria Violations
    h. Distributed Generation and Storage (kW), in operation
    i. Distributed Generation and Storage (kW), in queue
    j. Demand Response or other demand-side DER (kW) (EV chargers, EE, etc.)
7. By Feeder
    a. Forecasted Annual Peak Load
    b. Actual Annual Peak Load
    c. Actual Daytime Minimum Load
    d. Load shapes (seasonal)
    e. Load shapes (hourly)
    f. Hosting Capacity Results (min. and max)
    g. Hosting Capacity Criteria Violations
    h. Distributed Generation and Storage (kW), in operation
    i. Distributed Generation and Storage (kW), in queue
    j. Demand Response or other demand-side DER (kW) (EV chargers, EE, etc.)
8. By Node
    a. Forecasted Annual Peak Load
    b. Actual Annual Peak Load
    c. Actual Daytime Minimum Load
    d. Load shapes (seasonal)
    e. Load shapes (hourly)
    f. Hosting Capacity Results (min. and max)
    g. Hosting Capacity Criteria Violations
    h. Distributed Generation and Storage (kW), in operation
    i. Distributed Generation and Storage (kW), in queue
    j. Demand Response or other demand-side DER (kW) (EV chargers, EE, etc.)
9. By Secondary
    a. Forecasted Annual Peak Load
    b. Actual Annual Peak Load

[10] Minnesota Public Utilities Commission, Notice of Workgroup, July 2 2024. Page 6-7

c. Actual Daytime Minimum Load
d. Load shapes (seasonal)
e. Load shapes (hourly)
f. Hosting Capacity Results (min. and max)
g. Hosting Capacity Criteria Violations
h. Distributed Generation and Storage (kW), in operation
i. Distributed Generation and Storage (kW), in queue
j. Demand Response or other demand-side DER (kW) (EV chargers, EE, etc.)

As the Commission directed in that notice,

> The workgroup will seek to place the items from Attachment 1 into relevant portions of a framework with feedback from security stakeholders and parties using the NARUC Grid Data Sharing Playbook to guide engagement and feedback.[11]

Because we agree that the above list represents most of the relevant types of grid data that should be available to DER developers in Minnesota, we respectfully ask the Commission to modify the draft Framework to include this Attachment regarding the types of grid data that may be requested.

Unfortunately, as discussed earlier, the Draft Framework does not yet fully classify all of the data types discussed above into low, medium, or high risk categories. The Joint Parties respectfully suggest that in order to be considered complete, the Framework should also explicitly classify each data type above into the appropriate protective category, with clear guidance for classifying data types not explicitly listed in the Framework draft.

[11] Minnesota Public Utilities Commission, Notice of Workgroup, July 2 2024. Page 2

b) The Framework Should Explicitly List the Public Data Types That Are Already Accessible and Not Covered by this Framework Request Process

As noted in the Draft Framework, and the second Converge workgroup, any data that is publicly available is outside the scope of the Draft Framework, and therefore is not subject to the restrictions created.

> The Minnesota Grid Data Sharing Framework will not recategorize data that falls under existing classifications that prohibit sharing, and currently publicly available data that does not require protection measures and controls.[12]

At the end of these comments, please find Appendix A, submitted in this docket by MnSEIA and Cooperative Energy Futures on December 4, 2024. This list is provided as a set of examples of data that is already required to be public and accessible, from the MN DIP, and from the FERC Small Generator Interconnection Procedure (SGIP), respectively. The FERC SGIP is the interconnection procedure upon which MN DIP was based. This list, while not exhaustive, serves to demonstrate some of the considerable data required for DER interconnection that is outside of the scope of this framework. Using this list, or a similar list to define out-of-scope already public data will add further clarity to the bounds and powers of the Draft Framework.

The Joint Parties respectfully request that the Commission modify the Draft Framework by:

- Explicitly incorporating the list in Appendix A, or a similar list, to define public data that is out of scope for the Draft Framework.

[12] Converge Strategies, *Recommendations for a Grid Data Sharing Framework*, Docket 20-800. p. 7. (March 4, 2026)

VI. Conclusion

The Joint Parties would like to thank Converge Strategies and all workgroup participants for a fruitful and productive working group process. This Draft Framework, while still requiring improvement, is a positive step towards a uniform grid data request process in the state of Minnesota. The Commission can address issues with the Framework Report by more clearly defining the data inside and outside of scope (as requested above), refine timelines and the feedback process, streamline mitigation steps and improve overall clarity with the Draft Framework. Doing so will be a benefit to all parties in this docket and the state itself. An efficient, clear data request process will better enable Minnesota to meet its statutory clean energy goals, expedite interconnection, and create a stable, predictable process for collaborative work on the grid of tomorrow.

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Appendix A - Examples of Currently Public Grid Data

	State of Minnesota Distributed Energy Resources Interconnection Process (MN DIP), at 5	FERC, Small Generator Interconnection Agreements and Procedures, Final Rule, Order 792 at 23 (Nov. 22, 2013), at 923.
Total capacity in megawatts (MW)	1.4.2.1 Total capacity (in megawatts (MW)) of substation/area bus, bank or circuit based on normal or operating ratings likely to serve the proposed Point of Common Coupling	1.2.3.1 Total capacity (in MW) of substation/area bus, bank or circuit based on normal or operating ratings likely to serve the proposed Point of Interconnection.
Existing aggregate generation capacity	1.4.2.2 Existing aggregate generation capacity (in MW) interconnected to a substation/area bus, bank or circuit (i.e., amount of generation online) likely to serve the proposed Point of Common Coupling	1.2.3.2 Existing aggregate generation capacity (in MW) interconnected to a substation/area bus, bank or circuit (i.e., amount of generation online) likely to serve the proposed Point of Interconnection
Aggregate queued generation capacity (in MW)	1.4.2.3 Aggregate queued generation capacity (in MW) for a substation/area bus, bank or circuit (i.e., amount of generation in the queue) likely to serve the proposed Point of Common Coupling	1.2.3.3 Aggregate queued generation capacity (in MW) for a substation/area bus, bank or circuit (i.e., amount of generation in the queue) likely to serve the proposed Point of Interconnection.
Available capacity (in MW)	1.4.2.4 Available capacity (in MW) of substation/area bus or bank and circuit likely to serve the proposed Point of Common Coupling (i.e., total capacity less the sum of existing aggregate generation capacity and aggregate queued generation capacity).	1.2.3.4 Available capacity (in MW) of substation/area bus or bank and circuit likely to serve the proposed Point of Interconnection (i.e., total capacity less the sum of existing aggregate generation capacity and aggregate queued generation capacity)
Substation Nominal Voltage	1.4.2.5 Substation nominal distribution voltage and/or transmission nominal voltage if applicable.	1.2.3.5 Substation nominal distribution voltage and/or transmission nominal voltage if applicable
Distribution circuit nominal voltage	1.4.2.6 Nominal distribution circuit voltage at the proposed Point of Common Coupling.	1.2.3.6 Nominal distribution circuit voltage at the proposed Point of Interconnection.
Circuit Distance	1.4.2.7 Approximate circuit distance between the proposed Point of Common Coupling and the substation.	1.2.3.7 Approximate circuit distance between the proposed Point of Interconnection and the substation.

Actual or estimated peak load and minimum load data for relevant line segment	1.4.2.8 Relevant line section(s) actual or estimated peak load and minimum load data, including daytime minimum load as described in section 3.4.4.1 below and absolute minimum load, when available.	1.2.3.8 Relevant line section(s) actual or estimated peak load and minimum load data, including daytime minimum load as described in section 2.4.4.1.1 below and absolute minimum load, when available
Line Voltage Regulator	1.4.2.9 Whether the Point of Common Coupling is located behind a line voltage regulator.	
Protective and voltage regulating devices	1.4.2.10 Number and rating of protective devices and number and type (standard, bidirectional) of voltage regulating devices between the proposed Point of Common Coupling and the substation/area. Identify whether the substation has a load tap changer.	1.2.3.9 Number and rating of protective devices and number and type (standard, bi-directional) of voltage regulating devices between the proposed Point of Interconnection and the substation/area. Identify whether the substation has a load tap changer.
Phases available	1.4.2.11 Number of phases available on the Area EPS medium voltage system at the proposed Point of Common Coupling. If a single phase, distance from the threephase circuit.	1.2.3.10 Number of phases available at the proposed Point of Interconnection. If a single phase, distance from the three-phase circuit
Limiting conductor ratings	1.4.2.12 Limiting conductor ratings from the proposed Point of Common Coupling to the distribution substation.	1.2.3.11 Limiting conductor ratings from the proposed Point of Interconnection to the distribution substation.
Type of network	1.4.2.13 Whether the Point of Common Coupling is located on a spot network, grid network, or radial supply.	1.2.3.12 Whether the Point of Interconnection is located on a spot network, grid network, or radial supply
Existing or known constraints	1.4.2.14 Based on the proposed Point of Common Coupling, existing or known constraints such as, but not limited to, electrical dependencies at that location, short circuit interrupting capacity issues, power quality or stability issues on the circuit, capacity constraints, or secondary networks.	1.2.3.13 Based on the proposed Point of Interconnection, existing or known constraints such as, but not limited to, electrical dependencies at that location, short circuit interrupting capacity issues, power quality or stability issues on the circuit, capacity constraints, or secondary networks.