414 Nicollet Mall
Minneapolis, MN 55401

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March 13, 2026

—Via Electronic Filing—

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

RE: INITIAL COMMENTS
IN THE MATTER OF A VERIFIED FORMAL COMPLAINT OF HENNEPIN COUNTY AGAINST NORTHERN STATES POWER CO. D/B/A XCEL ENERGY REGARDING UNDER MINN. STAT. § 216B.164
DOCKET NO. E002/C-25-435

Dear Ms. Bergman:

Northern States Power Company, doing business as Xcel Energy, submits these Initial Comments to the Minnesota Public Utilities Commission (Commission) pursuant to the January 15, 2026 Notice of Comment Period regarding the Hennepin County Formal Complaint (Complaint).

Certain information in the filing is nonpublic and is Protected Information that is not in the public version of this filing. The information in this filing designated as Protected Data is specific customer information relating to one of its PV systems and is Trade Secret pursuant to Minn. Stat. § 13.37, subd. 1(b); is considered to be private not-public-data under Minn. Stat. §13.02, subd. 8a; and, is protected by the Commission orders as to what constitutes private account information in Docket No. E,G999/CI-12-1344. This information is subject to efforts from the customer to maintain its secrecy. This information derives independent economic value, actual or potential, to the customer from not being generally known to, and not being readily ascertainable by proper means by, other persons who can obtain economic value from its disclosure or use.

We have electronically filed this document with the Minnesota Public Utilities Commission, and copies have been served on the parties on the attached service list. Please contact Kristne Ruud at 612-216-7979 or Kristen.S.Ruud@xcelenergy.com if you have any questions regarding this filing.

Sincerely,

/s/

JAMES DENNISTON
ASSISTANT GENERAL COUNSEL

Enclosures
cc: Service List

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STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

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

IN THE MATTER OF A VERIFIED FORMAL COMPLAINT OF HENNEPIN COUNTY AGAINST NORTHERN STATES POWER CO. D/B/A XCEL ENERGY REGARDING UNDER MINN. STAT. § 216B.164	DOCKET NO. E002/C-25-435 **INITIAL COMMENTS**

INTRODUCTION

Northern States Power Company, doing business as Xcel Energy, submits these Initial Comments to the Minnesota Public Utilities Commission (Commission) pursuant to the January 15, 2026 Notice of Comment Period regarding the Hennepin County Formal Complaint (Complaint).

The Notice specified the following topics for comment:

- Does the Commission have jurisdiction over the subject matter of the Complaint?
- Are there reasonable grounds for the Commission to investigate these allegations?
- Is it in the public interest for the Commission to investigate these allegations upon its own motion?
- If the Commission chooses to investigate the Complaint, what procedures should be used to do so?

The Complaint is related to two solar projects owned by Hennepin County and currently under construction in Plymouth, Minnesota. The two projects are located within close proximity, approximately 0.2 miles from each other. The Complaint centers on the definition of a Qualifying Facility (QF) in Minn. Stat. §216B.164, Minn. R. 7835.0100, and the Federal Regulatory Commission's (FERC) regulations (18 CFR

292.203 and 204). For determining eligibility for net-metering rates, the Company appropriately applied the FERC QF definition and the FERC QF one-mile rule, and determined that the two projects are located on the same site, therefore constituting a single QF over 1 MW. Accordingly, they would not be eligible for the net metering rate codes that Hennepin County would prefer to use.[1] Instead, the Company has offered to use the recently approved tariffed Power Purchase Agreement (PPA) available to systems up to 5 MW,[2] or alternatively, to negotiate with Hennepin County a PPA that compensates for any export energy to the Company at an avoided cost rate.

Hennepin County's Complaint argues that federal regulations – including the QF definition and the FERC QF one-mile rule – do not apply to Minnesota's net metered facilities, which are governed under Minn. Stat. §216B.164. The Complaint maintains that the two solar projects should not be considered QFs at all, and instead they should be treated as two distinct net metered facilities.

As we explain in more detail below, the Complaint is ignoring the fundamental purpose of Minn. Stat. §216B.164 (Cogeneration and Small Power Production), which is to implement the Public Utility Regulatory Policies Act of 1978 (PURPA) and the related FERC regulations. Minn. Stat. §26B.164, Subdivision 2, par (a), specifically states that 18 CFR 292 applies to all Minnesota electric utilities, unless otherwise provided in section §216B.164. Moreover, Minn. R. 7835.0100, Subp. 19, specifically defines a "qualifying facility" as a cogeneration or small power production facility which satisfies the conditions established in 18 CFR 292. These conditions include the FERC QF one-mile rule at 18 CFR 292.204(a)(2). The Company appropriately applied these conditions to the Hennepin County projects and determined that they should be treated as a single QF exceeding 1 MW.

The Company requests that the Commission dismiss the Complaint because it is not based on reasonable grounds or merit, and because it is not in the public interest for the Commission to investigate the allegations.

The Company notes that the Complaint had included as attachments only selected written communications between the Parties. Table 1 below provides a complete list of these written communications in chronological order. We have included as attachments in our Initial Comments also those communications that were excluded from the Complaint, as indicated in Table 1.

[1] See, Tariff Sheets 9-4 through 9-4.3.
[2] See, Tariff Sheets 9-12.2 through 9-12.3.

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Table 1 – Chronological Listing of Written Communications

Date	Description	Where Attached
11/12/24	Xcel Energy email to Hennepin re: application of FERC QF one-mile rule	Complaint, Attachment 4
2/25/25	Hennepin County letter responding to 11/12/24 email	Xcel Energy Comments, Attachment A
3/12/25	Xcel Energy response to Hennepin County 2/25/25 letter	Complaint, Attachment 5
6/2/25	Hennepin County letter responding to Xcel Energy 3/12/25 letter	Xcel Energy Comments, Attachment B
6/6/25	Xcel Energy letter responding to Hennepin County 6/2/25 letter	Xcel Energy Comments, Attachment C
9/23/25	Hennepin County email re: 9/11/25 MPUC Order in Docket 24-389	Complaint, Attachment 6
10/2/25	Xcel Energy email in response to Hennepin County 9/23/25 email	Complaint, Attachment 6

The Company has also included the following additional attachments in our Initial Comments:

Table 2 – Additional Attachments Included

Attachment Number in these Initial Comments	Description
D	Minn. Stat. § 216B.164, shaded references to QF and net metered facilities
E	Minn. R. 7835, shaded references to QF and net metered facilities
F	FERC Order in *SunE B9 Holdings*, 157 FERC ¶ 61,044
G	General Diagram explaining FERC QF one mile rule
H	Excerpts from United Health Group February 18, 2025 filing in Docket 24-389

I. THE COMMISSION HAS JURISDICTION OVER THE SUBJECT MATTER

The Company agrees that the Commission has jurisdiction over the subject matter of the Complaint. Under Minn. Stat. §216B.09, the Commission has broad authority to consider complaints with respect to services provided by public utilities. As such, the Complaint relates to the Company's implementation of net metering tariffs, which have been approved by the Commission. According to Minn. Stat. § 216B.17, the Commission may investigate a complaint as it deems necessary or may dismiss a complaint without a hearing if in its opinion a hearing is not in the public interest. Formal complaints are also subject to Minn. R. 7829.1700 – 1900, which state in part that the Commission shall dismiss a complaint if the Commission concludes that it lacks jurisdiction or if there is no reasonable basis to investigate the matter.

II. THERE ARE NO "REASONABLE GROUNDS" OR "PUBLIC INTEREST" TO INVESTIGATE THE COMPLAINT

The Company requests that the Commission dismiss the Complaint because it has no merit, there are no reasonable grounds to investigate the matter, and it is not in the public interest for the Commission to investigate the allegations. As we describe below, the Company properly applied Minnesota law in determining net metering eligibility and in concluding that once both Hennepin County solar projects achieve Permission to Operate (PTO), they constitute a single QF and should be treated accordingly.

A. The Company Has Properly Applied FERC Rules and the Definition of QF

1. The Two Projects Are within 1 Mile from Each Other

Hennepin County has been constructing two solar facilities in Plymouth, Minnesota. A 620 kW solar array is located at the Adult Correctional Facility (ACF), at 1145 Shenandoah Lane North. A 720 kW solar array is located at the Public Safety Service Headquarters (PHS), at 1345 Shenandoah Lane North. **[PROTECTED DATA BEGINS**

PROTECTED DATA ENDS]. The approximate distance between these two solar facilities is about 0.2 miles (or 1,200 feet), as shown in the map below.[3] The combined capacity of the projects – 1,340 kW – is well over 1 MW.

[3] The Complaint, in par. 7, states that the two facilities are 0.17 miles from each other.

The Company appropriately applied the FERC definition and conditions for a QF and determined that since the ACF and PHS solar arrays are located within 1 mile from each other, they should be considered a single, 1.34 MW QF once they become operational. As a result, the two projects would not be eligible for the net metering rates that Hennepin County would prefer, namely the A55/A56 annual net metering rate for the ACH array and the A53/A54 monthly net metering rate for the PHS array. Only QFs that are less than 1 MW in size are eligible for these specific net metering rate codes.[4]

The Company has communicated to Hennepin County that when the first solar project achieves PTO, it is allowed to use the preferred monthly or annual net metering rate. **[PROTECTED DATA BEGINS**

PROTECTED DATA ENDS]. However, once the second facility achieves PTO, the projects together would be considered a single QF and no longer eligible for the monthly/annual net metering rates. Instead, the Company has offered to use the recently approved tariffed PPA available to systems up to 5 MW,[5] or alternatively, to negotiate with Hennepin County a PPA that compensates for any energy export to the Company at an avoided cost rate.[6]

[4] See, Tariff Sheets 9-4 through 9-4.3.
[5] See, Tariff Sheets 9-12.2 through 9-12.3.
[6] We provided this offer to Hennepin County before the Complaint was filed. See, for example the March 12, 2025 letter from Xcel Energy to Hennepin County attached as Attachment 5 to the Complaint, and the June 6, 2025 letter from Xcel Energy to Hennepin County attached as Attachment C to these comments.

2. QF Definitions in FERC Regulations and Minnesota Law Are the Same

One of the main arguments of the Complaint is that FERC regulations, and specifically the FERC definition and conditions for a QF, do not apply to Minnesota net metered facilities. However, this argument entirely ignores the fundamental purpose of Minn. Stat. §216B.164, which was to implement PURPA as well as FERC regulations related to PURPA. This section of Minnesota Law is often also referred to as the Minnesota PURPA Implementation Statute. The statute specifically states that the FERC regulations under PURPA "… *shall, unless otherwise provided in this section, apply to all Minnesota electric utilities* ….", and that "*Nothing in this section shall be construed to alter the rights and duties of any person pursuant to [PURPA]… and the [FERC] regulations thereunder*…." (Minn. Stat. § 216B.164, Subd. 2). The term "qualifying facility" is an established, essential, and regularly used term in FERC regulations that implemented PURPA, namely 18 CFR 292.

The basic principle of Minn. Stat. § 216B.164 is that Minnesota utilities are required to interconnect with and purchase electricity from cogeneration and small power production facilities only if they satisfy the conditions of a QF. Minnesota law has neither declined nor altered the FERC definition of QF. On the contrary, Minnesota Rules have explicitly adopted the FERC definition and conditions. Minn. R. 7835.0100, Subp. 19 states:

> **Qualifying facility.** "Qualifying facility" means a cogeneration or small power production facility *which satisfies the conditions established in Code of Federal Regulations, title 18, part 292 [i.e., 18 CFR 292]*. The initial operation date or initial installation date of a cogeneration or small power production facility must not prevent the facility from being considered a qualifying facility for the purposes of this chapter if it otherwise satisfies all stated conditions. [emphasis added]

Accordingly, whenever Minn. Stat. §216B.164 refers to a "qualifying facility," this means a facility that meets the definition, requirements, and conditions for a QF under FERC regulations.

3. FERC QF One-Mile Rule

When determining the size of a QF under FERC regulations, the capacity of separate facilities is combined if they are located on the same site, use the same energy resource, and are owned by the same entity or its affiliates (18 CFR 292.204(a)(1)). In

addition, there is an irreputable assumption that facilities that are located within 1 mile or less from each other and use the same power resource are located on the same site – this is the FERC QF one-mile rule (18 CFR 292.204(a)(2.i.A)). The exact language of these regulations is provided below:

§292.204. Criteria for qualifying small power production facilities.

(a) Size of the facility –

(1) Maximum size. Except as provided in paragraph (a)(4) of this section, the power production capacity of a facility for which qualification is sought, together with the power production capacity of any other small power production qualifying facilities that use the same energy resource, are owned by the same person(s) or its affiliates, and are located at the same site, may not exceed 80 megawatts.

(2) Method of calculation.

(i) (A) For purposes of this paragraph (a)(2), there is an irrebuttable presumption that affiliated small power production qualifying facilities that use the same energy resource and are located one mile or less from the facility for which qualification or recertification is sought are located at the same site as the facility for which qualification or recertification is sought.

The Hennepin County ACF and PHS solar arrays are located within one mile from each other, owned by the same or related entity, and use the same power resource. Based on the FERC criteria listed above, which have explicitly been adopted as conditions for a QF in Minnesota rules, ACF and PHS solar arrays should be treated as a single QF with 1.34 MW capacity.

While the Minnesota statutory definition of capacity applies to a "distributed generation facility," the FERC definition of a QF still applies. Minn. Stat. § 216B.164 and Minn. R. 7835 extensively reference "qualifying facilities" and by nature all distribution QFs include one or more distributed generation facilities.

4. FERC Decision in SunE B9 Holdings on the QF One-Mile Rule

We provide as Attachment F the FERC analysis in *SunE B9 Holdings* (157 FERC ¶ 61,044), issued on October 20, 2016. This decision is instructive on how to measure the capacity of a QF, and specifically addresses the definition of QF as provided for under 18 CFR 292. The specific context in this case was whether multiple PV inverters owned by affiliated developers within one mile of each other should be aggregated to determine if they constitute a single QF under the FERC QF one-mile rule. *SunE B9 Holdings* characterized these PV systems as eighteen physically separate 500 kW 'Facilities.' If the QF is larger than 1 MW in capacity, it must file a FERC Form 556 Self-Certification. *SunE B9 Holdings* had argued that it was exempt from the requirement to file FERC Form 556 because each inverter had a net power production capacity of less than 1 MW. In its decision, FERC aggregated the capacity

of each system within one mile from each other and determined that the QF was larger than 1 MW. Therefore, SunE needed to file FERC Form 556 Self-Certification for all of these inverters as a single facility in order to be considered as a QF.

FERC's decision in *SunE B9 Holdings* confirmed the application of the FERC QF one-mile rule – all small power production facilities that are owned by the same entity, powered by the same power source, and located within one mile of each other are considered to be a single small power production facility for purposes of QF certification. The one-mile rule functions as a definitive rule based on irrebuttable presumption, which means that FERC automatically determines that all facilities inside the one-mile periphery constitute a single QF at a single site.

The Company provides a diagram in Attachment G to help explain this concept. This diagram shows three 750 kW solar facilities of A, B, and C, which are connected to three different buildings and have different, points of interconnection to these buildings. All three systems are owned by the same entity and located within one mile of each other. All three systems are also powered by the same energy source – the sun. When the FERC QF one-mile rule is applied to this example to determine the size of a QF, there would be one 2.25 MW QF (3 x 750 kW). Therefore, these facilities would not be eligible for the Company's current net metering tariff, which has a 1 MW cap. The map on page 5 of these Initial Comments shows a similar scenario for the ACF and PHS solar arrays at issue, with the same result that these projects constitute a single QF.

5. A Net Metered Facility Is a Subset of a QF

The Complaint also argues that a "net metered facility" cannot be considered a "qualifying facility" and therefore the ACF and PHS solar projects should not be subject to the FERC QF one-mile rule. The Company disagrees, because there is no basis for this type of interpretation under Minn. Stat. §216B.164. Under this statute, facilities can "generate electricity from natural gas, renewable fuel, or a similarly clean fuel, and may include waste heat, cogeneration, or fuel cell technology" (Minn. Stat. §216B.164, Subd. 2a(h)(3)). A net metered facility is simply a type or a subset of a QF. Therefore by definition, every net metered facility is also a QF.

By definition, a "net metered facility" is a QF that is constructed for the purpose of offsetting energy use through the use of renewable energy or high-efficiency distributed generation sources (Minn. Stat. §216B.164, Subd. 2a (j)). If the net metered facility has a capacity above or below certain thresholds (depending on the circumstances, either 40 kW or 1000 kW), it is eligible for certain rates for compensation and may be subject to other requirements, such as the 120 percent rule

(Minn. Stat. §216B.164, Subd. 4c). The meaning of the term "capacity" is the same for QFs and "net metered facilities" as a subset of QFs. This is apparent in the fact that the applicable statutes and rules do not distinguish the two types of facilities in any other way than stating that net metered facilities are offsetting energy use through renewable energy or high-efficiency sources. State law equates the capacity determination for each in Subd 3 (pars. e and f) and in Subd 3a (par. b), and Minnesota Rule 7835 does likewise. Attachments D and E contain the Minnesota PURPA Implementation Statute and Minn. R. 7835, showing in highlights the use of terms "net metered facilities" and "qualifying facilities." State law requires that the Minnesota PURPA Implementing Statute and PURPA are in alignment and symmetrical on this issue.

Hennepin County has executed the Uniform Statewide Contract for Cogeneration and Small Power Production Facilities (Uniform Statewide Contract) for the ACF and PHS solar projects (Complaint, par. 8). This contract only applies to QFs and specifically states that the agreement is made between the utility and the QF. The Uniform Statewide Contract template is included in Minn. R. 7835.9910 and in the Company's tariff on Sheet 9-10. The Uniform Statewide Contract refers to the customer as a QF and equates a net metered facility as a QF.[7] We provide below an excerpt of the Uniform Statewide Contract template from our tariff:

[7] For example, see Uniform Statewide Contract (Minn. R. 7835.9910, par. 5) which states in part: "The Public Utility will buy electricity from a net metered facility under the current rate schedule filed with the Commission or will compensate the facility in the form of a kilowatt-hour credit on the facility's energy bill. If the net metered facility has at least 40 kilowatts capacity but less than 1,000 kilowatts capacity, the QF elects the rate schedule category hereinafter indicated …."

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

UNIFORM STATEWIDE CONTRACT FOR COGENERATION AND SMALL POWER PRODUCTION FACILITIES

Section No. 9
2nd Revised Sheet No. 10

UNIFORM STATEWIDE CONTRACT FOR COGENERATION AND SMALL POWER PRODUCTION FACILITIES

THIS CONTRACT is entered into _____ , _____ , by Northern States Power Company, a Minnesota corporation and wholly owned subsidiary of Xcel Energy Inc., (hereafter called "Utility") and _____ (hereafter called "QF").

RECITALS

The QF has installed electric generating facilities, consisting of _____ (Description of facilities), rated at ____ kilowatts of electricity, on property located at _____ _____ .

C

The QF is prepared to generate electricity in parallel with the Utility.

The QF's electric generating facilities meet the requirements of the Minnesota Public Utilities Commission (hereafter called "Commission") rules on Cogeneration and Small Power Production and any technical standards for interconnection the Utility has established that are authorized by those rules.

The Utility is obligated under federal and Minnesota law to interconnect with the QF and to purchase electricity offered for sale by the QF.

A contract between the QF and the Utility is required by the Commission's rules.

Although Hennepin County has executed the Uniform Statewide Contract as a QF for the ACF and PHS solar projects, the Complaint claims that the QF definition and conditions should not apply to these projects. This claim is inconsistent and in conflict with the provisions of the Uniform Statewide Contract.

Additionally, the Complaint referenced (par. 23) as support the stated purpose of the Minnesota PURPA Implementation Statute. Minn. Stat. § 216B.164, Subd. 1 states: "*This section shall at all times be construed in accordance with its intent to give the maximum possible encouragement to cogeneration and small power production consistent with protection of the ratepayers and the public.*" However, while the Complaint emphasized the goal of encouraging small power production, it did not give any weight to the fact that this must happen in a way that considers the public interest and is "*consistent with protection of the ratepayers and the public.*" The Company's position is consistent with the protection of the ratepayers and the public because it avoids unnecessary cross-subsidies and aligns with the state and federal law.

Expanding net metering beyond the Minnesota statutory cap, which mandates monthly net metering only for systems up to 1 MW, would not be in the public interest as it would effectively push more costs on other ratepayers. Monthly or

annual net metering would result in monthly or annual "banking" of energy, which would then reduce the amount of utility sales to the monthly or annually net metered customer. This is because the monthly or annual net metered customer would, on a monthly or annual basis, use periods of excess production from the PV system to help cover periods of time when their energy usage exceeds the production from the PV system. As a result, the customer's payments for the energy they receive from the utility would be reduced even though the customer's demand could significantly exceed the production of their PV system during some periods of time within the month or year. Therefore, this would reduce the recovery of the fixed costs of the utility in providing utility service, including the costs to provide system capacity to serve the customer during low production, high-usage time periods. Increasing the maximum limit for monthly net metering would exacerbate this effect because larger systems comprise a larger portion of the capacity, and also the costs, of the distribution system. Every dollar that the monthly net metered customer would save would need to be made up from other customers. This would amount to a cross-subsidy from other ratepayers (including low-income customers) to a large customer, which is not in the public interest.

Furthermore, and most importantly, Minn. Stat. § 216B.164, Subd. 1 cannot be given such broad interpretation that it could allow the violation of other parts of Minn. Stat. § 216B.164 or Minn. R. 7835, including the provisions that define qualifying facilities and implement net metering for systems under 1 MW. (See, for example, Minn. R. 7835.0100 (Subp. 19), .4011, .4012 (Subp. 2), .4017, and .9910). Hennepin County has not requested any variance to these rules or shown that such variance would be appropriate.

B. Specific Counts of the Complaint Have No Merit

1. Count I – Unlawful Restriction of Net Metering

Count I of the Complaint is titled "Unlawful Restriction of Net Metering." The thesis of this count is that the FERC QF one-mile rule does not apply here, because Hennepin County argues it has two net-metered facilities. As we have explained above, this premise is misplaced, the one-mile rule applies to the ACF and PHS solar arrays, and net metered facilities are a subset of QFs.

Hennepin County further argues that it would be unlawful for the Company to cancel the previously signed Uniform Statewide Contracts for these two projects. This is not correct, as these contracts, in par. 17, specifically allow either party to cancel the contract upon 30 days' notice. While the Company has not yet provided this notice, we intend to do so once both solar arrays have achieved PTO, because at that time

they would be treated as a single QF exceeding 1 MW. Therefore, they would no longer be eligible for the Uniform Statewide Contract, which only applies to QFs under 1 MW. By delaying to provide such notice until then, the Company is allowing Hennepin County to the maximum lawful extent to participate in monthly or annual net metering.

2. Count II – Illegal Ratemaking

Count II of the Complaint is titled "Illegal Ratemaking." The thesis of this count is that Minn. Stat. § 216B.164, Subd. 2a includes definitions of "capacity" and "distributed generation facility" that tether capacity to the point of interconnection or point of common coupling and therefore Hennepin County argues that the FERC QF one-mile rule does not apply. The Complaint also asserts that the "aggregated metering" provisions of the Company's tariff further support the position of Hennepin County because it has not chosen to aggregate metering for these two facilities. The Complaint concludes that based on these arguments, the two solar arrays are "distinct net metered facilities" (Complaint, par. 46). Hennepin County maintains that any cancellation of the two Uniform Statewide Contracts for the solar arrays would require a Company filing with the Commission, because this would be seeking to modify the contracts and Minn. Stat. § 216B.16, Subd. 1 requires a 60-day notice.

As pointed out above, the Minnesota rules have clear, unambiguous language that they mirror the FERC rules on the definition and conditions for a QF. And FERC rules define the capacity for a QF as the aggregate capacity of individual systems that are located within one mile, owned by the same entity, and using the same energy source. The allegations of the Complaint cannot change Minnesota rules or how they are applied, and the Company has properly applied the one-mile rule. In *SunE B9 Holdings*, FERC determined that 18 facilities owned by SunE and located within one mile of each other constituted a one QF. The same reasoning and similar result apply here.

There is no requirement that a customer must participate in "meter aggregation" in order for the one-mile rule to apply. Meter aggregation allows a QF customer with two adjacent parcels to use solar generation on one parcel to be applied to its bill on the second parcel. This program is offered on the Company's tariff sheet 9-8.1. As explained in that tariff, this program only applies to QFs having less than 1,000 kW capacity. Here the QF at issue is larger than 1 MW, and therefore the "meter aggregation" tariff program is inapplicable. Further, Hennepin County is arguing in its Complaint that it is not a QF and it is inconsistent for Hennepin County to seek to be categorized as a QF on this "meter aggregation" issue because it only applies to QFs

less than 1,000 kW. Additionally, the "meter aggregation" tariff program does not create a variance to the FERC QF one-mile rule. The FERC QF one-mile rule, by its terms employs an "irrebuttable presumption" (18 CFR 292.204(a)) of how to measure the size of a QF, and under this one-mile rule the two solar arrays exceed 1 MW.

Finally, the Company is not seeking to modify the tariffed Uniform Statewide Contract. This tariffed contract, in par. 17, allows either party to cancel this contract upon 30 days' notice. The use of this provision does not create a modification to the tariffed version of this contract. The statute cited by Hennepin County on this issue (Minn. Stat. § 216B.16, Subd. 1) is irrelevant as it applies to rate cases and has no application to the current situation.

3. Count III – Unreasonable, Prejudicial, and Discriminatory Practices

Count III of the Complaint is titled "Unreasonable, Prejudicial, and Discriminatory Practices." The thesis of this count is that the application of the one-mile rule repudiates the Uniform Statewide Contracts and deprives Hennepin County of the expected financial benefits of these contracts because the facilities are within one mile of each other. Hennepin County also argues that the Company is inconsistently applying the net metering rates to facilities under 1 MW, offering them to some facilities and denying them to others, such as the ACF and PSH solar arrays. Hennepin County maintains that this is discriminatory and violates the law, because the Company is offering Hennepin County less compensation at the avoided cost rates than it is entitled to.

As explained above, the Company has properly applied the FERC QF one-mile rule and the Unform Statewide Contract allows either party to cancel it on 30 days' notice. There is no repudiation of a contract when it is cancelled based on a cancellation provision included in the contract. Hennepin County is not entitled to compensation for energy delivered to the Company at an amount that exceeds the avoided cost of that energy. State statutes provide: "The commission shall set the rates for net input into the utility system based on avoided costs as defined in the Code of Federal Regulations, title 18, section 292.101, paragraph (b)(6), the factors listed in Code of Federal Regulations, title 18, section 292.304, and all other relevant factors." (Minn. Stat. § 216B.164, Subd. 3(c)). In addition "The qualifying facility shall be paid the utility's full avoided capacity and energy costs as negotiated by the parties, as set by the commission, or as determined through competitive bidding approved by the commission." (Minn. Stat. § 216B.164, Subd 4(b)).

Finally, the Company has applied the FERC QF one-mile rule to other similarly situated projects. For example, United Health Group pushed back on the Company's

application of the one-mile rule in Docket No. 24-389. This is reflected in their Comments filed on February 18, 2025 as well as in the Commission's Order issued on July 15, 2025. We have included excerpts of United Health Group's Comments in this docket as Attachment H. United Health Group did not seek reconsideration of the Commission's Order.

C. The Relief Requested is Inappropriate

The request for relief asks the Commission to find the following: the ACF and PSH arrays are each net metered facilities; Hennepin County is allowed to apply the A55/A56 annual net metering rate code to the ACF array; Hennepin County is allowed to apply the A53/A54 monthly net metering rate code to the PSH array; the Company is prevented from applying the one-mile rule here; and Hennepin County is granted "reasonable costs, disbursements, and attorney's fees pursuant to Minn. Stat. § 216B.164, Subd. 5 and Minn. R. 7835.4550."

None of this relief is appropriate. As explained above, the Company has taken the position that it will allow the first project that achieves PTO to utilize its desired net metering rate code. **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]**. Since this array alone is under 1 MW, it would qualify as a net metered facility. But, once both of these arrays have achieved PTO, then the size of the QF would exceed 1 MW as required by application of the one-mile rule. The Uniform Statewide Contract, by its terms, is a contract with a QF. Once the QF exceeds the 1 MW threshold then that QF may no longer take service under the Uniform Statewide Contract.

The Complaint requests also reasonable costs and attorney's fees, but this is not supported by the statute referenced in the Complaint. The cited statute (Minn. Stat. § 216B.164, Subd. 5) states:

> Subd. 5. **Dispute; resolution.**
>
> (a) In the event of disputes between a public utility and a qualifying facility, either party may request a determination of the issue by the commission. In any such determination, the burden of proof shall be on the public utility. The commission in its order resolving each such dispute shall require payments to the prevailing party of the prevailing party's costs, disbursements, and reasonable attorneys' fees, except that the qualifying facility will be required to pay the costs, disbursements, and attorneys' fees of the public utility only if the commission finds that

> the claims of the qualifying facility in the dispute have been made in bad faith, or are a sham, or are frivolous.

By the terms of this statute, it is only applicable to "disputes between a public utility and a qualifying facility." However, the main argument of the Complaint is that the two solar projects cannot be considered a QF. If Hennepin County prevails, and the Commission affirms this in its Order, then this statute on costs is not applicable. On the other hand, if the Commission determines that the two solar arrays in fact constitute a QF, then the Complaint should be dismissed, and Hennepin County would not be the prevailing party.

The cited rule (Minn. R. 7835.4550) leads to the same result. The cited rule in context states:

> **DISPUTES**
> **7835.4500 COMMISSION DETERMINATION.**
> In case of a dispute between a utility and a qualifying facility or an impasse in the negotiations between them, either party may request the commission to determine the issue. When the commission makes the determination, the burden of proof must be on the utility.
>
> **7835.4550 FEES AND COSTS.**
> In the order resolving the dispute, the commission shall require the prevailing party's reasonable costs, disbursements, and attorney's fees to be paid by the party against whom the issue or issues were adversely decided, except that a qualifying facility will be required to pay the costs, disbursements, and attorney's fees of the utility only if the commission finds that the claims of the qualifying facility have been made in bad faith or are a sham or frivolous.

Again, Minn. R. 7835.4550 only applies to disputes between a QF and a utility, as is described in Minn. R. 7835.4500. The rules mirror the provisions in the statute, and the result is the same as described above.

III. IF THE COMMISSION CHOOSES TO INVESTIGATE, WHAT PROCEDURES SHOULD THE COMMISSION UTILIZE?

The Complaint does not involve any disputed factual issues but instead focuses on questions related to the interaction between federal and state law as well as the applicability and interpretation of those laws. Accordingly, the Company does not believe that a contested case proceeding would be an appropriate procedure, if the

Commission decides to investigate the Complaint further. In our opinion, a proceeding that provides parties with an opportunity to file written comments would be more appropriate to address legal and policy questions, consistent with the nature and scope of the Complaint. However, these are only our preliminary thoughts on the proper procedures, and our position may change based on the comments that will be filed on the current Notice and the discussions that will take place during the subsequent Commission hearing.

CONCLUSION

The Company requests that the Commission dismiss the Complaint because it is not based on reasonable grounds or merit, and because it is not in the public interest for the Commission to investigate the allegations further. The Company has appropriately applied the FERC QF definition and conditions to the Hennepin County projects, consistent with the specific deference in Minn. Stat. § 216B.164 to PURPA and FERC, the mirroring of the FERC QF definition in Minn. R. 7835.0100, Subp. 19, and the fact that the statute refers to the capacity of the QF for purposes of applying net metering rates.

Dated: March 13, 2026

Northern States Power Company

OFFICE OF THE HENNEPIN COUNTY ATTORNEY
MARY F. MORIARTY COUNTY ATTORNEY

February 25, 2024

Mr. Jake Sedlacek
Key Account Manager
Jake.sedlacek@xcelenergy.com

Via email only

Dear Mr. Sedlacek:

In November, you provided an informal email opinion that the County's two separate solar arrays—located at the Adult Correctional Facility ("ACF array") and the Public Safety Services Headquarters ("PSS array")—would not be eligible for net metering because application of the "One Mile Rule" makes them a single qualifying facility whose capacity will exceed the net metering threshold. The county disputes this conclusion and requests that Xcel apply net metering to each array, consistent with Minn. Stat. § 216B.164. Please forward this letter to the appropriate legal counsel for Xcel.

Background

The ACF array is located at 1145 Shenandoah Lane North in Plymouth, Minnesota. On May 17, 2024 the County submitted an Interconnection Application for the ACF array with an expected capacity of 620 kW. Page two of that application indicated the County intended to take advantage of net metering. On August 1, 2024 Xcel offered the county an Interconnection Agreement (MN DIA) for the ACF array with a capacity of 620 kW. The County and Xcel entered into the Uniform Statewide Contract for Cogeneration and Small Power Production Facilities effective September 5, 2024, which provided the County would receive net metering compensation consistent with Rate Code A55 (corresponding with Sections 9.4.2 – 9.4.3 of the Minnesota Electric Rate Book).

The PSS array will be located at 1345 Shenandoah Lane North in Plymouth, Minnesota. On June 21, 2024 the County submitted an Interconnection Application for the PSS array with an expected capacity of 720 kW. Page two of that application indicated the County intended to take advantage of net metering. On October 2, 2024 Xcel offered the county an Interconnection Agreement (MN DIA) for the PSS array with a capacity of 720 kW. The County and Xcel entered into the Uniform Statewide Contract for Cogeneration and Small Power Production Facilities effective October 9, 2024, which provided the County would receive net metering compensation consistent with Rate Code 53 (corresponding with Sections 9.4.0 – 9.4.1 of the Minnesota Electric Rate Book).

Hennepin County Attorney's Office
Civil Division, A-20 Government Center, MC 200
300 South Sixth Street, Minneapolis, MN 55487
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612-348-5518

Analysis

The net metering benefit the County intends to utilize is created by Minn. Stat. § 216B.164 and not limited by the definition of "qualifying facility" in 18 C.F.R. 292.204. The federal regulation sets out specific criteria to be a qualifying facility under the Public Utility Regulatory Policies Act of 1978. The federal regulation limits "qualifying facilities that use the same energy resource, are owned by the same person(s) or its affiliates, and are located at the same site" to 80 megawatts of production. 18 C.F.R. 292.204(a). "[T]here is an irrebuttable presumption that affiliated small power production qualifying facilities that use the same energy resource and are located one mile or less from the facility for which qualification or recertification is sought are located at the same site as the facility for which qualification or recertification is sought." *Id.*

Minnesota's net metering benefit is not conditioned upon meeting the definition of a qualifying facility under the federal regulation. Minnesota provides that "a customer with a net metered facility having a capacity of 40 kilowatts or greater but less than 1,000 kilowatts that is interconnected to a public utility may elect to be compensated for the customer's net input into the utility system in the form of a kilowatt-hour credit on the customer's energy bill carried forward and applied to subsequent energy bills." Minn. Stat. § 216B.164, subd. 3(a)a. Moreover, "[a]ny net input supplied by the customer into the utility system that exceeds energy supplied to the customer by the utility during a calendar year must be compensated at the applicable rate." *Id.* This benefit shall "be construed in accordance with its intent to give the maximum possible encouragement to cogeneration and small power production consistent with protection of the ratepayers and the public." *Id.* at subd. 1. Applying an inapplicable definition of "qualifying facility" to Minnesota's net metering benefit runs counter to the purpose of the benefit.

Indeed, Minnesota's Public Utilities Commission has consistently recognized there is no bright-line test for co-location in the context of the net metering benefit. In Minnesota, "Community Solar Gardens shall be considered 'Co-Located' if they exhibit characteristics of a single development including, but not limited to, common ownership structure, an umbrella sale arrangement, shared interconnection, revenue-sharing arrangements, and common debt and equity financing." Order Adopting Partial Settlement, p. 15, Docket M-13-867 (Minn. P.U.C. Aug. 6, 2015). "That test allows consideration of geographical proximity, but neither proximity nor any other factor is dispositive of whether gardens are part of a single development." Order Approving Tariffs as Modified and Requiring Filing , p. 3, Docket M-13-867 (Minn. P.U.C. Dec. 15, 2015) ("The Commission will require Xcel to define co-location according to the definition approved by the Commission in its August 6 order" except that "gardens will not be considered co-located solely because the same entity provided tax-equity financing for the gardens.").

As applied here, only one of the five criteria (common ownership) weighs in favor of finding the ACF array and the PSS array are co-located. The County—a local governmental entity—is not establishing these arrays for purposes of profit. Importantly, the arrays have separate interconnection agreements.

To the extent Xcel disagrees with the County's determination that the ACF array and PSS are not co-located, please send any such written notice to my attention. The County looks forward to working with Xcel on these projects.

Best regards,

Rebecca Holschuh
Sr. Asst. Hennepin County Attorney

Cc: A.J. Van den Berghe, Hennepin County Energy Manager

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June 2, 2025

Via Email: James.R.Denniston@xcelenergy.com

James R. Denniston
Assistant General Counsel
Excel Energy
414 Nicollet Mall, 401-8
Minneapolis, MN 55401

Re: Hennepin County ACF and PSS Solar Net Metering Facilities

Dear Jim:

Our firm represents Hennepin County. We write in response to your March 12, 2025 letter with respect to the county's separate Adult Correctional Facility and Public Safety Services Headquarters' solar facilities. We outline below why FERC's "one-mile" rule is inapplicable to the county's solar facilities and the harm to the county should Xcel seek to abrogate its existing net metering contracts with the county by applying such a rule. The county respectfully requests a meeting with Xcel Energy senior representatives to resolve this matter expeditiously.

Background

Hennepin County recently completed construction of its 720 kW solar facility at its new Public Safety Services Headquarters in Plymouth and is in the process of building a second and separate 620 kW solar facility 0.17 miles from the PSS facility at its new Adult Correctional Facility in Plymouth. The two facilities will be separately metered and are served from different Xcel distribution substations. The county and Xcel entered separate Uniform Statewide Contracts for Cogeneration and Small Power Production Facilities for each of the arrays, effective September 5, 2024, and October 9, 2024, respectively. Under the Uniform Contracts, Xcel agreed to purchase the monthly net amount of electric energy produced by the solar arrays at rate codes A53/A54 and A55/A56.[1] The county financed

[1] Section 5 of the Uniform Contracts states that the "Utility will buy electricity from a net metered facility under the current rate schedule filed with the Commission or will compensate the facility in the form of a kilowatt-hour credit on the facility's energy bill."

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and constructed the arrays in reliance on the contracts and on the expectation it would receive net metering treatment from Xcel.

Following on a November 12, 2024 email to the county, on March 12, 2025, Xcel sent the county a letter in which it took the position that neither the ACF nor PSS arrays are eligible for net metering compensation because, combined, the capacity of the two arrays exceeds the net metering statute's 1 MW per facility limit. Xcel's position is that it is required to combine the capacity of the two solar facilities because of FERC's "one-mile rule." As Xcel is aware, this federal rule applies to "qualifying facilities" and provides that where a small power production facility *seeking QF status* is located one mile or less from an affiliated small power production QF that use the same energy resource, it will be irrebuttably presumed to be at the same site as the affiliated QF.[2] Under the federal Public Utility Regulatory Policies Act of 1978 (PURPA), enacted to introduce greater competition in the electric generation market and to promote renewable energy, no one QF can exceed 80 MW. FERC enacted the one-mile rule to prevent developers seeking to sell energy to utilities under PURPA's mandatory purchase obligation from essentially gaming the 80 MW limit by building more than one facility under separate limited liability companies in nearby locations that, combined, exceeded the 80 MW limit. To our knowledge, this is the first time Xcel is attempting to use this federal rule in the context of the state's net metering 1 MW limitation.

For the following reasons, FERC's one-mile rule is inapplicable to the state's net metering statute, and the county expects Xcel to honor the terms of its net metering contracts.

1. PURPA is inapplicable to state net metering.

PURPA and its implementing regulations are inapplicable to the state's net metering program. Under the Federal Power Act and PURPA Title II, FERC has jurisdiction over *wholesale sales* by public utilities or QFs, respectively. FERC has determined that under net metering programs, no purchase or sale of electricity at wholesale is taking place so long as a retail customer with on-site generation is not a net supplier of energy to the grid over the applicable retail billing period. Therefore, unless and until there is a

[2] *Qualifying Facility Rates and Requirements; Implementation Issues Under the Public Utility Regulatory Policies Act of 1978*, Order 872, 172 FERC ¶ 61,041, paragraph 469 (July 16, 2020)(Final Rule).

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demonstrated case in which net energy is being provided to the utility, FERC rules, including the one-mile rule, are inapplicable.[3] In 2009, FERC held "the Commission does not assert jurisdiction when the end-use customer that is also the owner of the generator receives a credit against its retail power purchases from the selling utility."[4] Indeed, in Xcel's recent docket before the MPUC to increase its net metering limit from one to five megawatts, Xcel admits that "net metering is an incentive mechanism that is outside the scope of PURPA."[5]

That FERC jurisdiction is absent in net metering programs is also why your reference to the *SunE B9 Holdings* decision is inapposite to the county's net metering facilities here. In *SunE*, all the QFs were selling energy under separate power purchase agreements to the interconnected utility (Duke). Consistent with *Sun Edison*, those sales constituted "sales for resale" and thus were wholesale sales over which, and unlike net metering sales at issue here, the FERC has explicit jurisdiction.

2. FERC's one-mile applies only to small power production facilities *seeking to qualify as QFs*, which the county is not.

As Xcel is aware, FERC recently revised its regulations governing qualifying small power producers and co-generators under PURPA. One of those changes related to its one-mile rule. FERC amended its criteria for qualifying small power production facilities with respect to the size of the facility, which now provides:

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[3] See, NARUC PURPA Title Compliance Manual, at 104. https://www.publicpower.org/system/files/documents/PURPA%20Title%20II%20Compliance%20Manual%202.0.pdf

[4] *Sun Edison LLC*, 129 FERC ¶ 61,146 (2009). While FERC has stated it would assert jurisdiction "[o]nly if the end-use customer participating in the net metering program produces more energy than it needs over the applicable billing period, and thus is considered to have made a net sale of energy to a utility over the applicable billing period," it has never actually done so. In fact, most recently, in *New England Ratepayers Ass'n*, 172 FERC ¶ 61,042 (2020), FERC specifically declined to answer whether credits to a retail customer under net metering are wholesale sales subject to FERC's jurisdiction because the energy is sold to the utility's retail load, or whether net metering is merely a function of retail billing, which falls under a state's jurisdiction.

[5] Xcel Energy Petition, November 20, 2024, MPUC Docket 24-389, at 3.

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> For purposes of this paragraph, there is an irrebuttable presumption that affiliated small power production qualifying facilities that use the same energy resource and are located one mile or less from the facility *for which qualification or recertification is sought* are located at the same site as the facility *for which qualification or recertification is sought*.[6]

The remainder of this rule also makes clear that the presumptions – for QFs more than one mile and less than 10 miles and for QFs located 10 miles or more from a related QF – apply *only* to small power production facilities that *seek to qualify as QFs*. There are certainly benefits of being a QF, including (i) the right to sell energy or capacity to an incumbent utility under the mandatory "put" provisions of PURPA, (ii) the right to purchase certain services from utilities, and (iii) relief from certain regulatory burdens.[7] Because the county does not seek (nor need) the benefit associated with QF status for its solar facilities and instead was relying on the state's net metering program, the one-mile rule is inapplicable.

3. Minnesota statutes and rules measure capacity at the point of interconnection, not by the one-mile rule.

Neither Minnesota statutes nor rules, nor Xcel's QF tariffs purport to measure a net metered facility's capacity by reference to the one-mile rule. Instead, they measure a distributed generation system's capacity in a straightforward, common-sense manner. Under the state law with respect to co-generation and small power production facilities, the term "capacity" is defined as "the number of megawatts alternating current (AC) *at the point of interconnection* between a distributed generation facility and a utility's electric system."[8] Similarly, under applicable Minnesota Public Utilities Commission rules, "capacity means the capability to produce, transmit, or deliver electric energy, and is measured by the number of megawatts alternating current *at the point of common coupling*."[9]

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6 18 C.F.R. § 292.204(a)(2)(i)(A) (emphasis added).

7 *See, e.g.,* https://www.ferc.gov/qf

8 Minn. Stat. § 216B.164, subd. 2A(c) (emphasis added).

9 Minn. R. 7835.0100, subp. 4 (emphasis added). "Point of common coupling" means the point where the . . . generation system, including the point of generator output, is connected to the

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Xcel's applicable tariffs also provide that the capacity of a distributed generation system is required to be measured based on "the total capacity of all of the customer's systems *which are on the same set of aggregated meters*." Minnesota Electric Rate Book – MPUC No. 2, Section No. 9, 2nd Revised at Sheet No. 1, INDIVIDUAL SYSTEM CPACITY LIMITS.[10] The ACF and PSS solar arrays are separately metered and are not aggregated, and each has its own Uniform Statewide Contract. Thus, the capacities of the arrays are required to be separately measured under Xcel's own tariff, and each array is measured at the point of interconnection is under 1 MWac.

4. By enforcing the one-mile rule, Xcel would breach its Uniform Statewide Contracts with the county.

The county and Xcel entered separate Uniform Statewide Contracts for each of the arrays pursuant to which the county was entitled to be compensated under the net metering rate codes under A53/A54 and A55/A56.[11] The contracts were effective September 5, 2024, and October 9, 2024, respectively. The county relied on these contracts in financing and in constructing the arrays. To the extent Xcel is now taking the position it will no longer honor those terms, such action would be a breach of its contractual obligations.

5. Public policy favors enforcing the contracts as executed.

Minnesota statutes 216B.164, subd. 1 states "[t]his section shall at all times be construed in accordance with its intent to give the *maximum possible encouragement* to cogeneration and small power production consistent with protection of the ratepayers and the public." (Emphasis supplied). Xcel's position that the county arrays should not be entitled to net metering because of an inapplicable, never adopted FERC one-mile rule is at odds with this legislative intent. As Xcel is aware, the one-mile rule was intended to

utility's electric power grid." The Uniform Statewide Contract for Cogeneration and Small Power Production Facilities the county signed for both the ACF and PSS facilities define "capacity" in the same manner.

[10] https://xcelnew.my.salesforce.com/sfc/p/#1U0000011ttV/a/8b000002r6DF/aS_MPyau2ll0kmxaQsWb7sIykOVTYIxTB7DCSRTF6bg

[11] "The Utility will buy electricity from a metered facility under the current rate schedule filed with the Commission or will compensate the facility in the form of a kilowatt-credit on the facility's energy bill." Section 6, Uniform Statewide Contract.

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prevent energy developers from exceeding the PURPA 80-MW limit by daisy-chaining affiliated QFs next to one another, which together exceeded 80 MW, and forcing the interconnected utilities to purchase the energy at the utilities' avoided cost. It was not intended to prohibit net metering projects under a program encouraged by the state and over which the FERC has repeatedly stated it has no legal jurisdiction.

Moreover, taken to its logical conclusion, Xcel's position would put the county in seeming violation of other FERC rules. Because the ACF and PSS facilities are each under 1 MW, and because the county did not wish to avail itself of the benefits of QF qualification, it was not required to file for QF certification with FERC for either of the facilities.[12] Under Xcel's reasoning, however, not only should the county have sought QF certification of the facilities with FERC, because the PSS facility has already been constructed, it may be in violation of FERC's QF certification rules and even subject to financial penalties for failing to having so registered. Given that the county entered, and Xcel signed, the Uniform Statewide net metering contracts in reliance on the inapplicability of the one-mile rule, such a result would certainly be inconsistent with the intent to give the maximum possible encouragement to small power production, and borders on the absurd.

6. MPUC Docket 24-389 does not affect the county's net metering contracts with Xcel.

In your March 12 letter, you reference MPUC docket 24-389, wherein you state that the "issue of applying the FERC 1-mile rule has been teed up for consideration." You then note the comment period had expired and that a Commission decision is expected in the coming months. While the reference to the 24-389 docket is not entirely clear, we do not expect any decision coming out of that docket to have any effect on the county's existing contracts with Xcel nor would we expect any decision in that docket to modify, alter or amend the manner in which the capacity of small power production facilities are measured under Minnesota law, including duly adopted rules.

As noted above, Minn. Stat. § 216B.164, subd. 2A(c) already enshrines in the law how the capacity of a small power production facility is measured, and there is no dispute that the ACF and PSS facilities have separate points of interconnection with Xcel. Indeed, they are served from different Xcel substations. While Xcel may have had salutary

[12] 18 C.F.R. 292.203(d)(1).

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objectives in initiating the docket, any Commission decision with respect to the one-mile rule does not make ineffective the otherwise controlling statute. Nor will that decision have any binding effect with respect to the county, who was not even a party to the docket.[13]

Conclusion

It is an understatement that your March 12 letter has created significant concern within the county. Not only did the county invest millions of dollars in reliance on its contracts with Xcel and the existing net metering rules, it is also interested in expanding its commitment to renewable energy throughout its footprint. Xcel's position threatens that commitment and, we surmise, a similar commitment by other municipal and private retail customers of Xcel alike.

I will reach out to you in the next week or so to arrange a meeting with senior representatives of our respective clients. In the interim, please do not hesitate to contact me. Thank you for your consideration.

Sincerely,

/s/ Todd J. Guerrero

Todd J. Guerrero

c: Daniel Rogan, Assistant County Administrator
daniel.rogan@hennepin.us

[13] To the extent the MPUC wanted to make FERC's one-mile rule a "statement of general applicability and future effect . . . adopted to implement or make specific the law enforced or administered by that agency," it would have needed to strictly follow the rulemaking procedures under Minnesota's Administrative Procedure Act. *See, e.g., White Bear Lake Care Ctr., Inc. v. Minn. Dep't of Pub. Welfare*, 319 N.W.2d 7, 9 (Minn. 1982)("[r]ules must be adopted in accordance with specific notice and comment procedures established by statute, and the failure to comply with necessary procedures results in invalidity of the rule").

James R. Denniston
Assistant General Counsel

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June 6, 2025

(Via email only to:
Todd.Guerrero@kutakrock.com)

Todd Guerrero
Kutak Rock LLP
60 South Sixth Street
Suite 3400
Minneapolis, MN 55402

Re: Hennepin County ACF and PSS Solar Arrays in Plymouth

Dear Todd:

Thank you for your letter of June 2, 2025 regarding what you have identified as the 720 kW PSS facility and the 620 kW ACF facility which are 0.17 miles from each other. We look forward to working with Hennepin County to get this resolved and to allow the operation of these facilities consistent with the public interest and applicable law.

We can make a senior representative of Xcel Energy available for a meeting with a senior representative from Hennepin County. We suggest that the meeting be without legal counsel present, but will go with your preference on this. After Hennepin County has let us know of its representative for this meeting, Xcel Energy will designate its appropriate representative. Below, we offer some initial thoughts on your letter.

We first note that you may not have understood our position. Your letter seems to state that Xcel Energy is not allowing Hennepin County to have net metering for the PSS and ACF facilities. This is not the case. Our March 12 letter, at page 4, made it clear that we are offering 15-minute net metering. Under this approach, Hennepin County can self-consume all production for each 15-minute period, and to the extent that there is any excess in any 15-minute period then the Company would pay Hennepin County for that excess production at the tariffed avoided cost rate. We also advocated for a standard tariff PPA offering for QFs up to 5 MW with net metering based on 15-minute metering with excess generation during any 15-minute period paid at the A51/A52 avoided costs rate codes. The Commission on May 8 voted to approve this tariff PPA in Docket No. 24-389. Our offer is still available. If you want to negotiate a different rate for energy exported to the Company, we can engage in discussion, but the rate needs to be at an avoided cost rate.

Next, a primary argument in your June 2025 letter is that Hennepin County is not seeking to have either of the two DER systems at issue be a Qualifying Facility (QF). We do not understand how this argument would help Hennepin County. In order to obtain the tariffed net metering service that Hennepin County seeks here under the A55/A56 net metering rate codes, any DER system would need to be a QF. The requirement to be a QF to participate in net metering is specified throughout the Company's net metering tariff, Uniform Statewide Contract, and the underlying MPUC rules at Minn. R. 7835.4012 (Compensation for QFs having less than 1,000 kW capacity), .4014 (QF Simultaneous Purchase and Sale Billing Rate), .4015 (QF Time-of-Day Purchase Rates), .4017 (Net Metered Facility, which is a subset of a QF) and .9910 (Uniform Statewide Contract, where the customer is referred to as a QF). So, if the two facilities at issue here are not a QF, then the tariffed net metering provisions under the A55/A56 rate codes that you seek to obtain under the Uniform Statewide Contract would not be available to Hennepin County. Further, if these two facilities together are a QF with a capacity in excess of 1,000 kW because they are within one-mile of each other then under Minn. R. 7835.4019 they must negotiate a contract with the utility. Our paragraph above references how we have tried to jump start this negotiation process.

Hennepin County is seeking to utilize the tariffed net metering provisions applicable to the A55/A56 rate codes that are only available to QFs. In arguing that it is entitled to these rate codes, Hennepin County:

1.) Alleges that the MPUC must first adopt the one-mile rule in a rulemaking before the one-mile rule can be applied here and should not be applied for determining eligibility of the state's net metering statute.
2.) Alleges that the FERC one-mile rule is only to be used to determine whether a project is under 80 MW.
3.) Alleges that this is the first time that Xcel Energy has attempted to apply the one-mile rule in determining whether a project meets the 1 MW limit for tariffed net metering.
4.) Alleges that capacity of a QF should be measured at the point of interconnection instead of using the one-mile rule.
5.) Alleges that capacity is measured based on aggregation of meters.
6.) Asserts that MPUC Docket No. 24-389 is not applicable here.
7.) States that there is signed Uniform Statewide Contracts between the parties for these two projects to apply the A55/A56 rate codes, that the County has relied upon these signed contracts to finance these projects, and applying the one-mile rule would result in a breach of the signed Uniform Statewide Contracts.

8.) Alleges that under the Xcel Energy reasoning that Hennepin County is violating FERC rules.

We address these points below.

Points 1 through 4 above address the application of the one-mile rule. Under the Commission's existing rules at Minn. R. 7835.0100, Subp. 19, the Commission has established the following definition:

> **Qualifying facility.** "Qualifying facility" means a cogeneration or small power production facility which satisfies the conditions established in Code of Federal Regulations, title 18, part 292. The initial operation date or initial installation date of a cogeneration or small power production facility must not prevent the facility from being considered a qualifying facility for the purposes of this chapter if it otherwise satisfies all stated conditions.

This is consistent with the enabling statute, Minn. Stat. § 216B.164, Subd. 2, which states that this statue "… as well as any rules promulgated by the commission to implement this section or [PURPA], as amended, and the [FERC] regulations thereunder, Code of Federal Regulations, title 18, part 292, as amended, shall, unless otherwise provided in this section, apply to all Minnesota electric utilities …" and "Nothing in this section shall be construed to alter the rights and duties of any person pursuant to [PURPA] and the [FERC] regulations thereunder …."

Accordingly, pursuant to the Commission rules, the term QF is defined consistent with the CFR and the FERC interpretation of those regulations. Our March 12, 2025 letter explained at length how FERC in the SunE decision applied the one-mile rule to determine whether a QF is larger than 1 MW capacity and that this analysis applies here. We will not repeat the points here. Your attempt to distinguish SunE is not on point. The focus of that decision was how to measure the size of a QF by applying the one-mile rule for purposes of determining whether the QF was larger than 1 MW. The FERC SunE order at page 6 mentioned that "… the one-mile rule of section 292.204(a)(2) [(part of Code of Federal Regulations, title 18, part 292)] is a size determination which the Commission has consistently applied generally to the regulations pursuant to PURPA." The distinctions that you assert, that in SunE there was a sale of the energy to the utility, did not weigh in the FERC's decision on applying the one-mile rule to determine the size of the QF.

Your June 2 letter argues that the one-mile rule is only used to determine if a facility exceeds the 80 MW QF limit. This is not correct. The FERC SunE decision applied the one-mile rule to determine the size of the QF and whether the QF exceeded 1 MW. Your June 2 letter argues that the state's net metering statute does not use the FERC one-mile rule. This is not correct. The state statute on net metering uses the term "qualifying facility" many times in the context of eligibility for net metering, and has proxied the FERC regulations. The Commission's rules, as quoted above, which implemented this state statute also proxied the FERC definition of QF. FERC is clear under its long-standing rule that the one-mile rule is to be applied for determining the size of a QF, and whether the QF is over 1 MW.

This is not the first time that Xcel Energy has applied the one-mile rule for determining whether a QF is larger than 1 MW. Historically, QF DER behind the meter net metering projects have typically been under 20 kW, with very few approaching 1 MW. The increases in size of QF DER net metered installations above 1 MW seeking net metered rates is a recent phenomenon. In Commission Docket 24-389, the record there showed that United HealthCare Group raised the dispute about their DER systems where, similar to your argument, they sought to have the Commission use "each interconnection point" instead of the one-mile rule to determine the size of these for purposes of determining whether together there was one QF in excess of 1 MW. There UnitedHealth noted on the record that they have 4 interconnection points within one-mile of each other. During the May 8 Agenda session in this docket, there was substantial discussion of the one-mile rule and the Commission vote aligned with applying the one-mile rule for determining the size of a QF for purposes of applying the size limitations of the net metering tariffs. We believe that the Commission's reasoning would be fully applicable here. As of the date of the present letter, the Commission has not yet issued a written order. So, the Hennepin County situation is not the first application of the one-mile rule, and to our belief we have acted consistently in applying the one-mile rule for determining the size of QF DER systems seeking net metering.

Here, Hennepin has admitted that the PSS has a capacity of 720 kW, and that the ACF has a capacity of 620 kW, and that they are 0.17 miles from each other. The Uniform Statewide Contract and the signed Interconnection Agreements for these systems reflects these same capacity sizes. Accordingly, by these contracts both parties have agreed on the size of these systems. But, while each system is under 1 MW, cumulatively under the one-mile rule they form a single QF which exceeds 1 MW, and this QF size is applicable once both systems have achieved operation.

Your argument on aggregation of meters conflates two different issues. Meter aggregation (under Minn. Stat. § 216B.164, Subd. 4a and tariff sheet 9-81) is available to

QF DER systems under 1 MW that qualify for the tariffed net metering that are on contiguous property to load, and this meter aggregation allows the DER production on one property to offset load on the adjacent property owned or leased by the same customer. The "same set" of aggregated meters refers to those on adjacent properties, has no application outside of this meter aggregation program, and is not used to determine the size of the QF.

Your claim about Xcel Energy breaching the Uniform Statewide Contract is misplaced. Xcel Energy has noted that when both systems are operational that the size of the QF would exceed the allowed size under the Uniform Statewide Contract. The Uniform Statewide Contract is not a perpetual contract. The Uniform Statewide Contract at par. 17 states that is may be cancelled by either party upon 30 days notice. Our March 12 letter at page 4 explained why it was proper to sign each Uniform Statewide Contract, and why it would be appropriate to cancel both of these once both of the systems at issue here are in operation. At the same time we would offer a PPA with 15-minute net metering at an avoided cost rate for a QF that is under 5 MW. There would be no breach of the Uniform Statewide Contract by giving notice of cancellation of the contract as allowed by each contract.

Xcel Energy believes that we have offered to Hennepin County a reasonable path forward, consistent with applicable law. Xcel Energy can not offer to Hennepin County more favorable terms than what it offers to its other similarly situated customers. Further, Xcel Energy can not provide legal advice to Hennepin County on how Hennepin County should proceed on whether or not to file a FERC Form 556.
We look forward to the upcoming meeting.

Sincerely,

/s/ James Denniston

Assistant General Counsel
Xcel Energy

Cc: Daniel Rogan, Assistant County Administrator
Daniel.Rogan@hennepin.us

Jake Sedlacek (via email: Jake.Sedlacek@xcelenergy.com)

216B.164 COGENERATION AND SMALL POWER PRODUCTION.

Subdivision 1. **Scope and purpose.**

This section shall at all times be construed in accordance with its intent to give the maximum possible encouragement to cogeneration and small power production consistent with protection of the ratepayers and the public.

Subd. 2. **Applicability; rights maintained.**

(a) This section as well as any rules promulgated by the commission to implement this section or the Public Utility Regulatory Policies Act of 1978, Public Law 95-617, Statutes at Large, volume 92, page 3117, as amended, and the Federal Energy Regulatory Commission regulations thereunder, Code of Federal Regulations, title 18, part 292, as amended, shall, unless otherwise provided in this section, apply to all Minnesota electric utilities, including cooperative electric associations and municipal electric utilities.

(b) Nothing in this section shall be construed to alter the rights and duties of any person pursuant to the Public Utility Regulatory Policies Act of 1978, Public Law 95-617, Statutes at Large, volume 92, page 3117, as amended, and the Federal Energy Regulatory Commission regulations thereunder, Code of Federal Regulation, title 18, part 292, as amended.

Subd. 2a. **Definitions.**

(a) For the purposes of this section, the following terms have the meanings given them.

(b) "Aggregated meter" means a meter located on the premises of a customer's owned or leased property that is contiguous with property containing the customer's designated meter.

(c) "Capacity" means the number of megawatts alternating current (AC) at the point of interconnection between a distributed generation facility and a utility's electric system.

(d) "Cogeneration" means a combined process whereby electrical and useful thermal energy are produced simultaneously.

(e) "Contiguous property" means property owned or leased by the customer sharing a common border, without regard to interruptions in contiguity caused by easements, public thoroughfares, transportation rights-of-way, or utility rights-of-way.

(f) "Customer" means the person who is named on the utility electric bill for the premises.

(g) "Designated meter" means a meter that is physically attached to the customer's facility that the customer-generator designates as the first meter to which net metered credits are to be applied as the primary meter for billing purposes when the customer is serviced by more than one meter.

(h) "Distributed generation" means a facility that:

(1) has a capacity of ten megawatts or less;

(2) is interconnected with a utility's distribution system, over which the commission has jurisdiction; and

(3) generates electricity from natural gas, renewable fuel, or a similarly clean fuel, and may include waste heat, cogeneration, or fuel cell technology.

(i) "High-efficiency distributed generation" means a distributed energy facility that has a minimum efficiency of 40 percent, as calculated under section 272.0211, subdivision 1.

(j) "Net metered facility" means an electric generation facility constructed for the purpose of offsetting energy use through the use of renewable energy or high-efficiency distributed generation sources.

(k) "Renewable energy" has the meaning given in section 216B.2411, subdivision 2.

(l) "Standby charge" means a charge imposed by an electric utility upon a distributed generation facility for the recovery of costs for the provision of standby services, as provided for in a utility's tariffs approved by the commission, necessary to make electricity service available to the distributed generation facility.

Subd. 3. **Purchases; small facilities.**

(a) This paragraph applies to cooperative electric associations and municipal utilities. For a qualifying facility having less than 40-kilowatt capacity, the customer shall be billed for the net energy supplied by the utility according to the applicable rate schedule for sales to that class of customer. A cooperative electric association or municipal utility may charge an additional fee to recover the fixed costs not already paid for by the customer through the customer's existing billing arrangement. Any additional charge by the utility must be reasonable and appropriate for that class of customer based on the most recent cost of service study. The cost of service study must be made available for review by a customer of the utility upon request. In the case of net input into the utility system by a qualifying facility having less than 40-kilowatt capacity, compensation to the customer shall be at a per kilowatt-hour rate determined under paragraph (c), (d), or (f).

(b) This paragraph applies to public utilities. For a qualifying facility having less than 1,000-kilowatt capacity, the customer shall be billed for the net energy supplied by the utility according to the applicable rate schedule for sales to that class of customer. In the case of net input into the utility system by a qualifying facility having: (1) more than 40-kilowatt but less than 1,000-kilowatt capacity, compensation to the customer shall be at a per kilowatt-hour rate determined under paragraph (c); or (2) less than 40-kilowatt capacity, compensation to the customer shall be at a per-kilowatt rate determined under paragraph (c) or (d).

(c) In setting rates, the commission shall consider the fixed distribution costs to the utility not otherwise accounted for in the basic monthly charge and shall ensure that the costs charged to the qualifying facility are not discriminatory in relation to the costs charged to other customers of the utility. The commission shall set the rates for net input into the utility system based on avoided costs as defined in the Code of Federal Regulations, title 18, section 292.101, paragraph (b)(6), the factors listed in Code of Federal Regulations, title 18, section 292.304, and all other relevant factors.

(d) Notwithstanding any provision in this chapter to the contrary, a qualifying facility having less than 40-kilowatt capacity may elect that the compensation for net input by the qualifying facility into the utility system shall be at the average retail utility energy rate. "Average retail utility energy rate" is defined as the average of the retail energy rates, exclusive of special rates based on income, age, or energy conservation, according to the applicable rate schedule of the utility for sales to that class of customer.

(e) If the qualifying facility or net metered facility is interconnected with a nongenerating utility which has a sole source contract with a municipal power agency or a generation and transmission utility, the nongenerating utility may elect to treat its purchase of any net input under this subdivision as being made on behalf of its supplier and shall be reimbursed by its supplier for any additional costs incurred in making the purchase. Qualifying facilities or net metered facilities having less than 1,000-kilowatt capacity if interconnected to a public utility, or less than 40-kilowatt capacity if interconnected to a cooperative electric association or municipal utility may, at the customer's option, elect to be governed by the provisions of subdivision 4.

(f) A customer with a qualifying facility or net metered facility having a capacity below 40 kilowatts that is interconnected to a cooperative electric association or a municipal utility may elect to be compensated for the customer's net input into the utility system in the form of a kilowatt-hour credit on the customer's energy bill carried forward and applied to subsequent energy bills. Any kilowatt-hour credits carried forward by the customer cancel at the end of the calendar year with no additional compensation.

Subd. 3a. **Net metered facility.**

(a) Except for customers receiving a value of solar rate under subdivision 10, a customer with a net metered facility having a capacity of 40 kilowatts or greater but less than 1,000 kilowatts that is interconnected to a public utility may elect to be compensated for the customer's net input into the utility system in the form of a kilowatt-hour credit on the customer's energy bill carried forward and applied to subsequent energy bills. Any net input supplied by the customer into the utility system that exceeds energy supplied to the customer by the utility during a calendar year must be compensated at the applicable rate.

(b) A public utility may not impose a standby charge on a net metered or qualifying facility:

(1) of 100 kilowatts or less capacity; or

(2) of more than 100 kilowatts capacity, except in accordance with an order of the commission establishing the allowable costs to be recovered through standby charges.

Subd. 4.**Purchases; wheeling; costs.**

(a) Except as otherwise provided in paragraph (c), this subdivision shall apply to all qualifying facilities having 40-kilowatt capacity or more as well as qualifying facilities as defined in subdivision 3 and net metered facilities under subdivision 3a, if interconnected to a cooperative electric

association or municipal utility, or 1,000-kilowatt capacity or more if interconnected to a public utility, which elect to be governed by its provisions.

(b) The utility to which the qualifying facility is interconnected shall purchase all energy and capacity made available by the qualifying facility. The qualifying facility shall be paid the utility's full avoided capacity and energy costs as negotiated by the parties, as set by the commission, or as determined through competitive bidding approved by the commission. The full avoided capacity and energy costs to be paid a qualifying facility that generates electric power by means of a renewable energy source are the utility's least cost renewable energy facility or the bid of a competing supplier of a least cost renewable energy facility, whichever is lower, unless the commission's resource plan order, under section 216B.2422, subdivision 2, provides that the use of a renewable resource to meet the identified capacity need is not in the public interest.

(c) For all qualifying facilities having 30-kilowatt capacity or more, the utility shall, at the qualifying facility's or the utility's request, provide wheeling or exchange agreements wherever practicable to sell the qualifying facility's output to any other Minnesota utility having generation expansion anticipated or planned for the ensuing ten years. The commission shall establish the methods and procedures to insure that except for reasonable wheeling charges and line losses, the qualifying facility receives the full avoided energy and capacity costs of the utility ultimately receiving the output.

(d) The commission shall set rates for electricity generated by renewable energy.

Subd. 4a. **Aggregation of meters.**

(a) For the purpose of measuring electricity under subdivisions 3 and 3a, a public utility must aggregate for billing purposes a customer's designated meter with one or more aggregated meters if a customer requests that it do so. To qualify for aggregation under this subdivision, a meter must be owned by the customer requesting the aggregation, must be located on contiguous property owned by the customer requesting the aggregation, and the total of all aggregated meters must be subject to the size limitation in this section.

(b) A public utility must comply with a request by a customer-generator to aggregate additional meters within 90 days. The specific meters must be identified at the time of the request. In the event that more than one meter is identified, the customer must designate the rank order for the aggregated meters to which the net metered credits are to be applied. At least 60 days prior to the beginning of the next annual billing period, a customer may amend the rank order of the aggregated meters, subject to this subdivision.

(c) The aggregation of meters applies only to charges that use kilowatt-hours as the billing determinant. All other charges applicable to each meter account shall be billed to the customer.

(d) A public utility will first apply the kilowatt-hour credit to the charges for the designated meter and then to the charges for the aggregated meters in the rank order specified by the customer. If the net metered facility supplies more electricity to the public utility than the energy usage recorded by the customer-generator's designated and aggregated meters during a monthly billing period, the public utility shall apply credits to the customer's next monthly bill for the excess kilowatt-hours.

(e) With the commission's prior approval, a public utility may charge the customer-generator requesting to aggregate meters a reasonable fee to cover the administrative costs incurred in implementing the costs of this subdivision, pursuant to a tariff approved by the commission for a public utility.

Subd. 4b. **Limiting cumulative generation.**

The commission may limit the cumulative generation of net metered facilities under subdivisions 3 and 3a. A public utility may request the commission to limit the cumulative generation of net metered facilities under subdivisions 3 and 3a upon a showing that such generation has reached four percent of the public utility's annual retail electricity sales. The commission may limit additional net metering obligations under this subdivision only after providing notice and opportunity for public comment. In determining whether to limit additional net metering obligations under this subdivision, the commission shall consider:

(1) the environmental and other public policy benefits of net metered facilities;

(2) the impact of net metered facilities on electricity rates for customers without net metered systems;

(3) the effects of net metering on the reliability of the electric system;

(4) technical advances or technical concerns; and

(5) other statutory obligations imposed on the commission or on a utility.

The commission may limit additional net metering obligations under clauses (2) to (4) only if it determines that additional net metering obligations would cause significant rate impact, require significant measures to address reliability, or raise significant technical issues.

Subd. 4c. **Individual system capacity limits.**

(a) A public utility that provides retail electric service may require customers with a facility of 40-kilowatt capacity or more and participating in net metering and net billing to limit the total generation capacity of individual distributed generation systems by either:

(1) for wind generation systems, limiting the total generation system capacity kilowatt alternating current to 120 percent of the customer's on-site maximum electric demand; or

(2) for solar photovoltaic and other distributed generation, limiting the total generation system annual energy production kilowatt hours alternating current to 120 percent of the customer's on-site annual electric energy consumption.

(b) Limits under paragraph (a) must be based on standard 15-minute intervals, measured during the previous 12 calendar months, or on a reasonable estimate of the average monthly maximum demand or average annual consumption if the customer has either:

(1) less than 12 calendar months of actual electric usage; or

(2) no demand metering available.

Subd. 5.**Dispute; resolution.**

(a) In the event of disputes between a public utility and a qualifying facility, either party may request a determination of the issue by the commission. In any such determination, the burden of proof shall be on the public utility. The commission in its order resolving each such dispute shall require payments to the prevailing party of the prevailing party's costs, disbursements, and reasonable attorneys' fees, except that the qualifying facility will be required to pay the costs, disbursements, and attorneys' fees of the public utility only if the commission finds that the claims of the qualifying facility in the dispute have been made in bad faith, or are a sham, or are frivolous.

(b) Notwithstanding subdivisions 9 and 11, a qualifying facility over 20 megawatts may, until December 31, 2022, request that the commission resolve a dispute with any utility, including a cooperative electric association or municipal utility, under paragraph (a).

Subd. 6. **Rules and uniform contract.**

(a) The commission shall promulgate rules to implement the provisions of this section. The commission shall also establish a uniform statewide form of contract for use between utilities and a net metered or qualifying facility having less than 1,000-kilowatt capacity if interconnected to a public utility or less than 40-kilowatt capacity if interconnected to a cooperative electric association or municipal utility.

(b) The commission shall require the qualifying facility to provide the utility with reasonable access to the premises and equipment of the qualifying facility if the particular configuration of the qualifying facility precludes disconnection or testing of the qualifying facility from the utility side of the interconnection with the utility remaining responsible for its personnel.

(c) The uniform statewide form of contract shall be applied to all new and existing interconnections established between a utility and a net metered or qualifying facility having less than 40-kilowatt capacity, except that existing contracts may remain in force until terminated by mutual agreement between both parties.

Subd. 7.

[Repealed, 1994 c 465 art 1 s 27]

Subd. 8. **Interconnection required; obligation for costs.**

(a) Utilities shall be required to interconnect with a qualifying facility that offers to provide available energy or capacity and that satisfies the requirements of this section.

(b) Nothing contained in this section shall be construed to excuse the qualifying facility from any obligation for costs of interconnection and wheeling in excess of those normally incurred by the utility for customers with similar load characteristics who are not cogenerators or small power producers, or from any fixed charges normally assessed such nongenerating customers.

Subd. 9. **Municipal electric utility.**

For purposes of this section only and with respect to municipal electric utilities only, the term "commission" means the governing body of each municipal electric utility that adopts and has in

effect rules implementing this section which are consistent with the rules adopted by the Minnesota Public Utilities Commission under subdivision 6. As used in this subdivision, the governing body of a municipal electric utility means the city council of that municipality; except that, if another board, commission, or body is empowered by law or resolution of the city council or by its charter to establish and regulate rates and days for the distribution of electric energy within the service area of the city, that board, commission, or body shall be considered the governing body of the municipal electric utility.

Subd. 10. **Alternative tariff; compensation for resource value.**

(a) A public utility may apply for commission approval for an alternative tariff that compensates customers through a bill credit mechanism for the value to the utility, its customers, and society for operating distributed solar photovoltaic resources interconnected to the utility system and operated by customers primarily for meeting their own energy needs.

(b) If approved, the alternative tariff shall apply to customers' interconnections occurring after the date of approval. The alternative tariff is in lieu of the applicable rate under subdivisions 3 and 3a.

(c) The commission shall after notice and opportunity for public comment approve the alternative tariff provided the utility has demonstrated the alternative tariff:

(1) appropriately applies the methodology established by the department and approved by the commission under this subdivision;

(2) includes a mechanism to allow recovery of the cost to serve customers receiving the alternative tariff rate;

(3) charges the customer for all electricity consumed by the customer at the applicable rate schedule for sales to that class of customer;

(4) credits the customer for all electricity generated by the solar photovoltaic device at the distributed solar value rate established under this subdivision;

(5) applies the charges and credits in clauses (3) and (4) to a monthly bill that includes a provision so that the unused portion of the credit in any month or billing period shall be carried forward and credited against all charges. In the event that the customer has a positive balance after the 12-month cycle ending on the last day in February, that balance will be eliminated and the credit cycle will restart the following billing period beginning on March 1;

(6) complies with the size limits specified in subdivision 3a;

(7) complies with the interconnection requirements under section 216B.1611; and

(8) complies with the standby charge requirements in subdivision 3a, paragraph (b).

(d) A utility must provide to the customer the meter and any other equipment needed to provide service under the alternative tariff.

(e) The department must establish the distributed solar value methodology in paragraph (c), clause (1), no later than January 31, 2014. The department must submit the methodology to the

commission for approval. The commission must approve, modify with the consent of the department, or disapprove the methodology within 60 days of its submission. When developing the distributed solar value methodology, the department shall consult stakeholders with experience and expertise in power systems, solar energy, and electric utility ratemaking regarding the proposed methodology, underlying assumptions, and preliminary data.

(f) The distributed solar value methodology established by the department must, at a minimum, account for the value of energy and its delivery, generation capacity, transmission capacity, transmission and distribution line losses, and environmental value. The department may, based on known and measurable evidence of the cost or benefit of solar operation to the utility, incorporate other values into the methodology, including credit for locally manufactured or assembled energy systems, systems installed at high-value locations on the distribution grid, or other factors.

(g) The credit for distributed solar value applied to alternative tariffs approved under this section shall represent the present value of the future revenue streams of the value components identified in paragraph (f).

(h) The utility shall recalculate the alternative tariff on an annual cycle, and shall file the recalculated alternative tariff with the commission for approval.

(i) Renewable energy credits for solar energy credited under this subdivision belong to the electric utility providing the credit.

(j) The commission may not authorize a utility to charge an alternative tariff rate that is lower than the utility's applicable retail rate until three years after the commission approves an alternative tariff for the utility.

(k) A utility must enter into a contract with an owner of a solar photovoltaic device receiving an alternative tariff rate under this section that has a term of at least 20 years, unless a shorter term is agreed to by the parties.

(l) An owner of a solar photovoltaic device receiving an alternative tariff rate under this section must be paid the same rate per kilowatt-hour generated each year for the term of the contract.

Subd. 11. **Cooperative electric association.**

(a) For purposes of this section only, the term "commission" means the board of directors of a cooperative association that (1) elects, by resolution, to assume the authority delegated to the Public Utilities Commission over cooperative electric associations under this section, and (2) adopts and has in effect rules implementing this section. The rules must provide for a process to resolve disputes that arise under this section, and must include a provision that a request by either party for mediation of the dispute by an independent third party must be implemented in accordance with paragraph (b). A cooperative electric association that has adopted a resolution and rules under this subdivision is exempt from regulation by the Public Utilities Commission under this section.

(b) In the event of a dispute between a cooperative electric association and one or more of its members, either party may request mediation of the dispute only after all attempts to settle the

dispute under the cooperative electric association's dispute resolution process have been exhausted. The parties must mutually agree upon the selection of a mediator, who must be listed on the roster of neutrals for civil matters established by the state court administrator under Rule 114.12 of Minnesota's General Rules of Practice for the District Courts. The cooperative electric association shall pay 90 percent of the cost of mediation, and the member or members who initiated the dispute shall pay ten percent of the cost of mediation.

(c) Except as provided in paragraph (d), any proceedings concerning the activities of a cooperative electric association under this section that are pending at the Public Utilities Commission on May 31, 2017, are terminated on that date.

(d) The Public Utilities Commission may complete its investigation in Docket No. 16-512 to assess whether the methodology used by cooperative associations to establish a fee under subdivision 3, paragraph (a), complies with state law if the commission determines that completing the investigation is necessary to protect the public interest, in which case it shall complete the investigation no later than December 31, 2017. A methodology that the commission determines complies with state law may not be challenged in a dispute under this section. If the commission determines that a methodology does not comply with state law, it shall clearly state the changes necessary to bring the methodology into compliance, and a cooperative electric association shall modify its methodology in accordance with the commission's directives.

(e) For a cooperative electric association that elects to operate under the provisions of paragraph (a), disputes arising under this section subsequent to a cooperative electric association's modification of its methodology under paragraph (d) shall be addressed under the cooperative association's rules and paragraph (b), as applicable.

Subd. 12. **Customer's access to electricity usage data.**

A utility must provide a customer's electricity usage data to the customer within ten days of the date the utility receives a request from the customer that is accompanied by evidence that the energy usage data is relevant to the interconnection of a qualifying facility on behalf of the customer. For the purposes of this subdivision, "electricity usage data" includes but is not limited to: (1) the total amount of electricity used by a customer monthly; (2) usage by time period if the customer operates under a tariff where costs vary by time of use; and (3) usage data that is used to calculate a customer's demand charge.

History:

1981 c 237 s 1; 1983 c 301 s 166-171; 1984 c 640 s 32; 1991 c 315 s 1; 1993 c 356 s 1; 1996 c 305 art 2 s 38; 2013 c 85 art 9 s 1-10; 2013 c 125 art 1 s 39; 2013 c 132 s 1; 1Sp2015 c 1 art 3 s 21; 2017 c 94 art 10 s 5-8; 2023 c 60 art 12 s 13

CHAPTER 7835, COGENERATION AND SMALL POWER PRODUCTION

7835.0100 DEFINITIONS.

Subpart 1. **Applicability.**

For purposes of this chapter, the following terms have the meanings given them in this part.

Subp. 2. **Average annual fuel savings.**

"Average annual fuel savings" means the annualized difference between the system fuel costs that the utility would have incurred without the additional generation facility and the system fuel costs the utility is expected to incur with the additional generation facility.

Subp. 2a. **Average retail utility energy rate.**

"Average retail utility energy rate" means, for any class of utility customer, the quotient of the total annual class revenue from sales of electricity minus the annual revenue resulting from fixed charges, divided by the annual class kilowatt-hour sales. Data from the most recent 12-month period available before each filing required by parts 7835.0300 to 7835.1200 must be used in the computation.

Subp. 3. **Backup power.**

"Backup power" means electric energy or capacity supplied by the utility to replace energy ordinarily generated by a qualifying facility's own generation equipment during an unscheduled outage of the facility.

Subp. 4. **Capacity.**

"Capacity" means the capability to produce, transmit, or deliver electric energy, and is measured by the number of megawatts alternating current at the point of common coupling between a qualifying facility and a utility's electric system.

Subp. 5. **Capacity costs.**

"Capacity costs" means the costs associated with providing the capability to deliver energy. The utility capital costs consist of the costs of facilities used to generate, transmit, and distribute electricity and the fixed operating and maintenance costs of these facilities.

Subp. 6. **Commission.**

"Commission" means the Minnesota Public Utilities Commission.

Subp. 6a. **Customer.**

"Customer" means the person named on the utility electric bill for the premises.

Subp. 7. **Energy.**

"Energy" means electric energy, measured in kilowatt-hours.

Subp. 8. **Energy costs.**

"Energy costs" means the variable costs associated with the production of electric energy. They consist of fuel costs and variable operating and maintenance expenses.

Subp. 9. **Firm power.**

"Firm power" means energy delivered by the qualifying facility to the utility with at least a 65 percent on-peak capacity factor in the month. The capacity factor is based upon the qualifying facility's maximum on-peak metered capacity delivered to the utility during the month.

Subp. 10. **Generating utility.**

"Generating utility" means a utility which regularly meets all or a portion of its electric load through the scheduled dispatch of its own generating facilities.

Subp. 11. **Incremental cost of capital.**

"Incremental cost of capital" means the current weighted cost of the components of a utility's capital structure, each cost weighted by its proportion of the total capitalization.

Subp. 12. **Interconnection costs.**

"Interconnection costs" means the reasonable costs of connection, switching, metering, transmission, distribution, safety provisions, and administrative costs incurred by the utility that are directly related to installing and maintaining the physical facilities necessary to permit interconnected operations with a qualifying facility. Costs are considered interconnection costs only to the extent that they exceed the corresponding costs which the utility would have incurred if it had not engaged in interconnected operations, but instead generated from its own facilities or purchased from other sources an equivalent amount of electric energy or capacity. Costs are considered interconnection costs only to the extent that they exceed the costs the utility would incur in selling electricity to the qualifying facility as a nongenerating customer.

Subp. 13. **Interruptible power.**

"Interruptible power" means electric energy or capacity supplied by the utility to a qualifying facility subject to interruption under the provisions of the utility's tariff applicable to the retail class of customers to which the qualifying facility would belong irrespective of its ability to generate electricity.

Subp. 14. **Maintenance power.**

"Maintenance power" means electric energy or capacity supplied by a utility during scheduled outages of the qualifying facility.

Subp. 15. **Marginal capital carrying charge rate in the first year of investment.**

"Marginal capital carrying charge rate in the first year of investment" means the percentage factor by which the amount of a new capital investment in a generating unit would have to be multiplied to obtain an amount equal to the total additional first year amounts for the cost of equity and debt

capital, income taxes, property and other taxes, tax credits (amortized over the useful life of the generating unit), depreciation, and insurance which would be associated with the new capital investment and would account for the likely inflationary or deflationary changes in the investment cost due to the one-year delay in building the unit.

Subp. 15a. **Net metered facility.**

"Net metered facility" means an electric generation facility constructed for the purpose of offsetting energy use through the use of renewable energy or high-efficiency distributed generation sources.

Subp. 16. **Nongenerating utility.**

"Nongenerating utility" means a utility which has no electric generating facilities, or a utility whose electric generating facilities are used only during emergencies or readiness tests, or a utility whose electric generating facilities are ordinarily dispatched by another entity.

Subp. 17. **On-peak hours.**

"On-peak hours" means, for utilities whose rates are regulated by the commission, those hours which are defined as on-peak for retail ratemaking. For any other utility, on-peak hours are either those hours formally designated by the utility as on-peak for ratemaking purposes or those hours for which its typical loads are at least 85 percent of its average maximum monthly loads.

Subp. 17a. **Point of common coupling.**

"Point of common coupling" means the point where the qualifying facility's generation system, including the point of generator output, is connected to the utility's electric power grid.

Subp. 17b. **Public utility.**

"Public utility" has the meaning given in Minnesota Statutes, section 216B.02, subdivision 4.

Subp. 18. **Purchase.**

"Purchase" means the purchase of electric energy or capacity or both from a qualifying facility by a utility.

Subp. 19. **Qualifying facility.**

"Qualifying facility" means a cogeneration or small power production facility which satisfies the conditions established in Code of Federal Regulations, title 18, part 292. The initial operation date or initial installation date of a cogeneration or small power production facility must not prevent the facility from being considered a qualifying facility for the purposes of this chapter if it otherwise satisfies all stated conditions.

Subp. 20. **Sale.**

"Sale" means the sale of electric energy or capacity or both by an electric utility to a qualifying facility.

Subp. 20a. **Standby charge.**

"Standby charge" means the rate or fee a utility charges for the recovery of costs for the provision of standby service or standby power.

Subp. 20b. **Standby service.**

"Standby service" means:

A. for public utilities, service or power that includes backup or maintenance services, as described in the public utility's commission-approved standby tariff, necessary to make electricity service available to the distributed generation facility; and

B. for a utility not subject to the commission's rate authority, the service associated with the applicable tariff in effect under Minnesota Statutes, section 216B.1611, subdivision 3, clause (2).

Subp. 21. **Supplementary power.**

"Supplementary power" means electric energy or capacity supplied by the utility which is regularly used by a qualifying facility in addition to that which the facility generates itself.

Subp. 22. **System emergency.**

"System emergency" means a condition on a utility's system which is imminently likely to result in significant disruption of service to customers or to endanger life or property.

Subp. 23. **System incremental energy costs.**

"System incremental energy costs" means amounts representing the hourly energy costs associated with the utility generating the next kilowatt-hour of load during each hour.

Subp. 24. **Utility.**

"Utility" means:

A. for the purposes of parts 7835.1300 to 7835.1800 and 7835.4500 to 7835.4550, any public utility, including municipally owned electric utilities or cooperative electric associations, that sells electricity at retail in Minnesota; or

B. for the purposes of parts B. for the purposes of 7835.0200 to 7835.1200, 7835.1900 to to 7835.4400, 7835.4600 to 7835.6100, 7835.9910, and 7835.9920, any public utility, including municipally owned electric utilities and cooperative electric associations, that sells electricity at retail in Minnesota, except those municipally owned electric utilities that have adopted and have in effect rules consistent with this chapter.

7835.0200 SCOPE AND PURPOSE.

The purpose of this chapter is to implement certain provisions of Minnesota Statutes, section 216B.164; the Public Utility Regulatory Policies Act of 1978, United States Code, title 16, section 824a-3; and the Federal Energy Regulatory Commission regulations, Code of Federal Regulations, title 18, part 292. Nothing in this chapter excuses any utility from carrying out its responsibilities under these provisions of state and federal law. This chapter must at all times be

applied in accordance with its intent to give the maximum possible encouragement to cogeneration and small power production consistent with protection of the ratepayers and the public.

FILING REQUIREMENTS

7835.0300 FILING DATES.

Within 60 days after the effective date of this chapter, on January 1, 1985, and every 12 months thereafter, each utility must file with the commission, for its review and approval, a cogeneration and small power production tariff. The tariff for generating utilities must contain schedules A to G, except that generating utilities with less than 500,000,000 kilowatt-hour sales in the calendar year preceding the filing may substitute their retail rate schedules for schedules A and B. The tariff for nongenerating utilities must contain schedules C, D, E, F, and H, and may, at the option of the utility, contain schedules A and B, using data from the utility's wholesale supplier.

7835.0400 FILING OPTION.

If, after the January 1, 2015, filing, schedule C is the only change in the cogeneration and small power production tariff to be filed in a subsequent year, the utility may notify the commission in writing, by the date the tariff is due, that there is no other change in the tariff. This notification and new schedule C will serve as a substitute for the refiling of the complete tariff in that year.

7835.0500 SCHEDULE A.

Schedule A must contain the estimated system average incremental energy costs by seasonal peak and off-peak periods for each of the next five years. For each seasonal period, system incremental energy costs must be averaged during system daily peak hours, system daily off-peak hours, and all hours in the season. The energy costs must be increased by a factor equal to 50 percent of the line losses shown in schedule B. Schedule A must describe in detail the method used to determine the on-peak and off-peak hours and seasonal periods and must show the resulting on-peak and off-peak and seasonal hours selected.

7835.0600 SCHEDULE B.

Subpart 1. **Information required.**

Schedule B must contain the information listed in subparts 2 to 6.

Subp. 2. **Planned utility generating facility additions.**

Schedule B must contain a description of all planned utility generating facility additions anticipated during the next ten years, including:

A. name of unit;

B. nameplate rating;

C. fuel type;

D. in-service date;

E. completed cost in dollars per kilowatt in the year in which the plant is expected to be put in service, including allowance for funds used during construction;

F. anticipated average annual fixed operating and maintenance costs in dollars per kilowatt;

G. energy costs associated with the unit, including fuel costs and variable operating and maintenance costs;

H. projected average number of kilowatt-hours per year the plant will generate during its useful life; and

I. average annual fuel savings resulting from the addition of this generating facility, stated in dollars per kilowatt.

Subp. 3. **Planned firm capacity purchases.**

Schedule B must contain a description of all planned firm capacity purchases, other than from qualifying facilities, during the next ten years, including:

A. year of the purchase;

B. name of the seller;

C. number of kilowatts of capacity to be purchased;

D. capacity cost in dollars per kilowatt; and

E. associated energy cost in cents per kilowatt-hour.

Subp. 4. **Percentage of line losses.**

Schedule B must contain the utility's overall average percentage of line losses due to the distribution, transmission, and transformation of electric energy.

Subp. 5. **Net annual avoided capacity cost.**

Schedule B must contain the utility's net annual avoided capacity cost stated in dollars per kilowatt-hour averaged over the on-peak hours and the utility's net annual avoided capacity cost stated in dollars per kilowatt-hour averaged over all hours. These figures must be calculated as follows in items A to I:

A. The completed cost per kilowatt of the utility's next major generating facility addition, as reported in schedule B, must be multiplied by the utility's marginal capital carrying charge rate in the first year of investment. If the utility is unable to determine this carrying charge rate as specified, the rate of 15 percent must be used.

B. The dollar amount resulting from the calculation set forth in item A must be discounted to present value, as of the midpoint of the reporting year, from the in-service date of the generating unit. The discount rate used must be the incremental cost of capital.

C. The figure for average annual fuel savings per kilowatt described in subpart 2, item I must be discounted to present value using the procedure of item B.

D. The number resulting from the calculation in item C must be subtracted from the number resulting from the calculation in item B. This is the net annual avoided capacity cost stated in dollars per kilowatt at present value.

E. The net annual avoided capacity cost calculated in item D must be multiplied by 1.15 to recognize a reserve margin.

F. The figure determined from the calculation of item E must be increased by the present value of the anticipated average annual fixed operating and maintenance costs as reported in subpart 2, item F. The present value must be determined using the procedure of item B.

G. The figure determined from the calculation of item F must be increased by one-half of the percentage amount of the average system line losses as shown on schedule B.

H. The annual dollar per kilowatt figure, as calculated in accordance with item G, must be divided by the annual number of hours in the on-peak period as specified in schedule A. The resulting figure is the utility's net annual on-peak avoided capacity cost in dollars per kilowatt-hour.

I. The annual dollar per kilowatt figure resulting from the calculation specified in item G must be divided by the total number of hours in the year. The resulting figure is the utility's net annual avoided capacity cost in dollars per kilowatt-hour averaged over all hours.

Subp. 6. **Net annual avoided capacity cost.**

If the utility has no planned generating facility additions for the ensuing ten years, but has planned additional capacity purchases, other than from qualifying facilities, during the ensuing ten years, schedule B must contain its net annual avoided capacity cost stated in dollars per kilowatt-hour averaged over the on-peak hours and the utility's net annual avoided capacity costs stated in dollars per kilowatt-hour averaged over all hours. These must be calculated as follows in items A and B:

A. The annual capacity purchase amount, in dollars per kilowatt, for the utility's next planned capacity purchase, other than from a qualifying facility, must be discounted to present value as of the midpoint of the reporting year, from the year of the planned capacity purchase. The discount rate used must be the incremental cost of capital.

B. The net annual avoided capacity cost must be computed by applying the figure determined in item A to the steps enumerated in subpart 5, items D to I, excluding item F.

Subp. 7. **Avoidable capacity costs.**

If the utility has neither planned generating facility additions nor planned additional capacity purchases, other than from qualifying facilities, during the ensuing ten years, the utility must be deemed to have no avoidable capacity costs.

7835.0650 SCHEDULE C.

Schedule C must contain the calculation of the average retail utility energy rates.

7835.0700 SCHEDULE D.

Schedule D must contain all standard contracts to be used with qualifying facilities, containing applicable terms and conditions.

7835.0800 SCHEDULE E.

Schedule E must contain the utility's safety standards, required operating procedures for interconnected operations, and the functions to be performed by any control and protective apparatus. These standards and procedures must not be more restrictive than the standards contained in the electrical code under part 7835.2100 or the interconnection standards distributed to customers under part 7835.4750. The utility may include in schedule E suggested types of equipment to perform the specified functions. No standard or procedure may be established to discourage cogeneration or small power production.

7835.0900 SCHEDULE F.

Schedule F must contain procedures for notifying affected qualifying facilities of any periods of time when the utility will not purchase electric energy or capacity because of extraordinary operational circumstances which would make the costs of purchases during those periods greater than the costs of internal generation.

7835.1000 SCHEDULE G.

Schedule G must contain and describe all computations made by the utility in determining schedules A and B.

7835.1100 SCHEDULE H; SPECIAL RULE FOR NONGENERATING UTILITIES.

Schedule H must list the rates at which a nongenerating utility purchases energy and capacity. If the nongenerating utility has more than one wholesale supplier, schedule H must list the rates of that supplier from which purchases may first be avoided. If the nongenerating utility with more than one wholesale supplier also chooses to file schedules A and B, the data on schedules A and B must be obtained from that supplier from which purchases may first be avoided.

7835.1200 AVAILABILITY OF FILINGS.

All filings required by parts 7835.0300 to 7835.1100 must be filed in the commission's electronic filing system and be maintained at the utility's general office and any other offices of the utility where rate case filings are kept. These filings must be available for public inspection at the commission and at the utility offices during normal business hours.

REPORTING REQUIREMENTS

7835.1300 GENERAL REPORTING REQUIREMENTS.

Each utility interconnected with a qualifying facility must provide the commission with the information in parts 7835.1400 to 7835.1800 annually on or before March 1, and in such form as the commission may require.

7835.1400 AVERAGE RETAIL UTILITY ENERGY BILLED QUALIFYING FACILITIES.

For qualifying facilities under average retail utility energy billing, the utility must provide the commission with the following information:

A. a summary of the total number of interconnected qualifying facilities, the type of interconnected qualifying facilities by energy source, and the name plate ratings of such units;

B. for each qualifying facility type, the total kilowatt-hours delivered per month to the utility by all average retail utility energy rate qualifying facilities;

C. for each qualifying facility type, the total kilowatt-hours delivered per month by the utility to all average retail utility energy rate qualifying facilities; and

D. for each qualifying facility type, the total net energy delivered per month to the utility by average retail utility energy rate qualifying facilities.

7835.1500 OTHER QUALIFYING FACILITIES.

For all qualifying facilities not under average retail utility energy billing, the utility must provide the commission with the following information:

A. a summary of the total number of interconnected qualifying facilities, the type of interconnected qualifying facilities, and the nameplate ratings of such units; and

B. for each qualifying facility type, the total kilowatt-hours delivered per month to the utility, reported by on-peak and off-peak periods to the extent that data is available.

7835.1600 WHEELING.

The utility must provide a summary of all wheeling activities undertaken with respect to qualifying facilities.

7835.1700 MAJOR IMPACTS.

The utility may provide a statement of any major impacts that cogeneration or small power production has had on the utility's system.

7835.1800 EFFECTIVENESS.

The utility may provide a statement of the effectiveness of Minnesota Statutes, section 216B.164 and this chapter in encouraging cogeneration and small power production, as observed by the utility.

CONDITIONS OF SERVICE

7835.1900 REQUIREMENT TO PURCHASE.

The utility must purchase energy and capacity from any qualifying facility which offers to sell energy to the utility and agrees to the conditions in this chapter.

7835.2000 WRITTEN CONTRACT.

A written contract must be executed between the qualifying facility and the utility.

7835.2100 ELECTRICAL CODE COMPLIANCE.

Subpart 1. **Compliance; standards.**

The interconnection between the qualifying facility and the utility must comply with the requirements in the most recently published edition of the National Electrical Safety Code issued by the Institute of Electrical and Electronics Engineers. The interconnection is subject to subparts 2 and 3.

Subp. 2. **Interconnection.**

The qualifying facility is responsible for complying with all applicable local, state, and federal codes, including building codes, the National Electrical Code (NEC), the National Electrical Safety Code (NESC), and noise and emissions standards. The utility must require proof that the qualifying facility is in compliance with the NEC before the interconnection is made. The qualifying facility must obtain installation approval from an electrical inspector recognized by the Minnesota State Board of Electricity.

Subp. 3. **Generation system.**

The qualifying facility's generation system and installation must comply with the American National Standards Institute/Institute of Electrical and Electronics Engineers (ANSI/IEEE) standards applicable to the installation.

7835.2200 RESPONSIBILITY FOR APPARATUS.

The qualifying facility, without cost to the utility, must furnish, install, operate, and maintain in good order and repair any apparatus the qualifying facility needs in order to operate in accordance with schedule E.

7835.2400 LEGAL STATUS NOT AFFECTED.

Nothing in this chapter affects the responsibility, liability, or legal rights of any party under applicable law or statutes. No party may require the execution of an indemnity clause or hold harmless clause in the written contract as a condition of service.

7835.2600 TYPES OF POWER TO BE OFFERED; STANDBY SERVICE.

Subpart 1. **Service to be offered.**

The utility must offer maintenance, interruptible, supplementary, and backup power to the qualifying facility upon request.

Subp. 2. **Standby service; public utility.**

A public utility may not impose a standby charge for standby service on a qualifying facility having 100 kilowatt capacity or less. A utility imposing rates on a qualifying facility having more than 100 kilowatt capacity must comply with an order of the commission establishing allowable costs.

Subp. 3. **Standby service; cooperative or municipality.**

A cooperative electric association or municipal utility must offer a qualifying facility standby power or service consistent with its applicable tariff for such service adopted under Minnesota Statutes, section 216B.1611, subdivision 3, clause (2).

7835.2800 DISCONTINUING SALES DURING EMERGENCY.

The utility may discontinue sales to the qualifying facility during a system emergency, if the discontinuance and recommencement of service is not discriminatory.

RATES

7835.3000 RATES FOR UTILITY SALES TO A QUALIFYING FACILITY TO BE GOVERNED BY TARIFF.

Except as otherwise provided in part 7835.3100, rates for sales to a qualifying facility must be governed by the applicable tariff for the class of electric utility customers to which the qualifying facility belongs or would belong were it not a qualifying facility.

7835.3100 PETITION FOR SPECIFIC SALES RATES.

Any qualifying facility or utility may petition the commission for establishment of specific rates for supplementary, maintenance, backup, or interruptible power.

7835.3150 INTERCONNECTION WITH COOPERATIVE ELECTRIC ASSOCIATION OR MUNICIPAL UTILITY.

Parts 7835.3200 to 7835.4000 apply to interconnections between a qualifying facility and a cooperative electric association or municipal utility.

7835.3200 STANDARD RATES FOR PURCHASES BY COOPERATIVE ELECTRIC ASSOCIATIONS AND MUNICIPAL UTILITIES FROM QUALIFYING FACILITIES.

Subpart 1. **Qualifying facilities with 100 kilowatt capacity or less.**

For qualifying facilities with capacity of 100 kilowatts or less, standard purchase rates apply. The utility must make available three types of standard rates, described in parts 7835.3300, 7835.3400, and 7835.3500. The qualifying facility with a capacity of 100 kilowatts or less must choose interconnection under one of these rates, and must specify its choice in the written contract required in part 7835.2000. Any net credit to the qualifying facility must, at its option, be credited to its account with the utility or returned by check within 15 days of the billing date. The option chosen must be specified in the written contract required in part 7835.2000. Qualifying facilities remain responsible for any monthly service charges and demand charges specified in the tariff under which they consume electricity from the utility.

Subp. 2. **Qualifying facilities over 100 kilowatt capacity.**

A qualifying facility with more than 100 kilowatt capacity has the option to negotiate a contract with a utility or, if it commits to provide firm power, be compensated under standard rates.

7835.3300 AVERAGE RETAIL UTILITY ENERGY RATE.

Subpart 1. **Applicability.**

The average retail utility energy rate is available only to qualifying facilities with capacity of less than 40 kilowatts which choose not to offer electric power for sale on either a time-of-day basis or a simultaneous purchase and sale basis.

Subp. 2. **Method of billing.**

The utility must bill the qualifying facility for the excess of energy supplied by the utility above energy supplied by the qualifying facility during each billing period according to the utility's applicable retail rate schedule.

Subp. 3. **Additional calculations for billing.**

When the energy generated by the qualifying facility exceeds that supplied by the utility during a billing period, the utility must compensate the qualifying facility for the excess energy at the average retail utility energy rate.

7835.3400 SIMULTANEOUS PURCHASE AND SALE BILLING RATE.

Subpart 1. **Scope.**

The simultaneous purchase and sale rate is available only to qualifying facilities with capacity of less than 40 kilowatts which choose not to offer electric power for sale on a time-of-day basis.

Subp. 2. **Method of billing.**

The qualifying facility must be billed for all energy and capacity it consumes during a billing period according to the utility's applicable retail rate schedule.

Subp. 3. **Compensation to qualifying facility.**

The utility must purchase all energy and capacity which is made available to it by the qualifying facility. At the option of the qualifying facility, its entire generation must be deemed to be made available to the utility. Compensation to the qualifying facility must be the sum of items A and B.

A. The energy component must be the appropriate system average incremental energy costs shown on schedule A; or if the generating utility has not filed schedule A, the energy component must be the energy rate of the retail rate schedule, applicable to the qualifying facility, filed in lieu of schedules A and B; or if the nongenerating utility has not filed schedule A, the energy component must be the energy rate shown on schedule H.

B. If the qualifying facility provides firm power to the utility, the capacity component must be the utility's net annual avoided capacity cost per kilowatt-hour averaged over all hours shown on schedule B; or if the generating utility has not filed schedule B, the capacity component must be the demand charge per kilowatt, if any, of the retail rate schedule, applicable to the qualifying facility, filed in lieu of schedules A and B, divided by the number of hours in the billing period; or if the nongenerating utility has not filed schedule B, the capacity component must be the capacity cost per kilowatt shown on schedule H, divided by the number of hours in the billing period. If the qualifying facility does not provide firm power to the utility, no capacity component may be included in the compensation paid to the qualifying facility.

7835.3500 TIME-OF-DAY PURCHASE RATES.

Subpart 1. **Applicability.**

Time-of-day rates are required for qualifying facilities with capacity of 40 kilowatts or more and less than or equal to 100 kilowatts, and they are optional for qualifying facilities with capacity less than 40 kilowatts. Time-of-day rates are also optional for qualifying facilities with capacity greater than 100 kilowatts if these qualifying facilities provide firm power.

Subp. 2. **Method of billing.**

The qualifying facility must be billed for all energy and capacity it consumes during each billing period according to the utility's applicable retail rate schedule. Any utility rate-regulated by the commission may propose time-of-day retail rate tariffs which require qualifying facilities that choose to sell power on a time-of-day basis to also purchase power on a time-of-day basis.

Subp. 3. **Compensation to qualifying facility.**

The utility must purchase all energy and capacity which is made available to it by the qualifying facility. Compensation to the qualifying facility must be the sum of items A and B.

A. The energy component must be the appropriate on-peak and off-peak system incremental costs shown on schedule A; or if the generating utility has not filed schedule A, the energy component must be the energy rate of the retail rate schedule, applicable to the qualifying facility, filed in lieu of schedules A and B; or if the nongenerating utility has not filed schedule A, the energy component must be the energy rate shown on schedule H.

B. If the qualifying facility provides firm power to the utility, the capacity component must be the utility's net annual avoided capacity cost per kilowatt-hour averaged over the on-peak hours as shown on schedule B; or if the generating utility has not filed schedule B, the capacity component must be the demand charge per kilowatt, if any, of the retail rate schedule, applicable to the qualifying facility, filed in lieu of schedules A and B, divided by the number of on-peak hours in the billing period; or if the nongenerating utility has not filed schedule B, the capacity component must be the capacity cost per kilowatt shown on schedule H, divided by the number of on-peak hours in the billing period. The capacity component applies only to deliveries during on-peak hours. If the qualifying facility does not provide firm power to the utility, no capacity component may be included in the compensation paid to the qualifying facility.

7835.3600 CONTRACTS NEGOTIATED BY CUSTOMER.

Except as provided in part 7835.3900, a qualifying facility with capacity greater than 100 kilowatts must negotiate a contract with the utility setting the applicable rates for payments to the customer of avoided capacity and energy costs.

7835.3700 AMOUNT OF CAPACITY PAYMENTS; CONSIDERATIONS.

The qualifying facility which negotiates a contract under part 7835.3600 must be entitled to the full avoided capacity costs of the utility. The amount of capacity payments must be determined through consideration of:

A. the capacity factor of the qualifying facility;

B. the cost of the utility's avoidable capacity;

C. the length of the contract term;

D. reasonable scheduling of maintenance;

E. the willingness and ability of the qualifying facility to provide firm power during system emergencies;

F. the willingness and ability of the qualifying facility to allow the utility to dispatch its generated energy;

G. the willingness and ability of the qualifying facility to provide firm capacity during system peaks;

H. the sanctions for noncompliance with any contract term; and

I. the smaller capacity increments and the shorter lead times available when capacity is added from qualifying facilities.

7835.3800 FULL AVOIDED ENERGY COSTS.

The qualifying facility which negotiates a contract under part 7835.3600 must be entitled to the full avoided energy costs of the utility. The costs must be adjusted as appropriate to reflect line losses.

7835.3900 QUALIFYING FACILITIES OF GREATER THAN 100 KILOWATTS.

Nothing in parts 7835.3600 to 7835.3800 prevents a utility from connecting qualifying facilities of greater than 100 kilowatts under its standard rates.

7835.4000 UTILITY TREATMENT OF COSTS.

All purchases from qualifying facilities with capacity of 100 kilowatts or less, and purchases of energy from qualifying facilities with capacity of over 100 kilowatts must be considered an energy cost in calculating an electric utility's fuel adjustment clause.

7835.4010 INTERCONNECTION WITH PUBLIC UTILITY.

Parts 7835.4011 to 7835.4023 apply to interconnections between a qualifying facility and a public utility.

7835.4011 STANDARD RATES FOR PURCHASES BY PUBLIC UTILITIES FROM QUALIFYING FACILITIES.

Subpart 1. **Standard rates.**

For qualifying facilities with less than 1,000 kilowatt capacity, standard rates apply. The utility must make available the types of standard rates described in parts 7835.4012 to 7835.4015. Qualifying facilities remain responsible for any monthly service charges and demand charges specified in the tariff under which they consume electricity from the utility.

Subp. 2. **Negotiated rates.**

A qualifying facility with 1,000 kilowatt capacity or more has the option to negotiate a contract with a utility or, if it commits to provide firm power, be compensated under standard rates.

7835.4012 COMPENSATION.

Subpart 1. **Facilities with less than 40 kilowatt capacity.**

A qualifying facility with less than 40 kilowatt capacity has the option to be compensated at the average retail utility energy rate, the simultaneous purchase and sale billing rate, or the time-of-day billing rate.

Subp. 2. **Facilities with at least 40 kilowatt capacity but less than 1,000 kilowatt capacity.**

A qualifying facility with at least 40 kilowatt capacity but less than 1,000 kilowatt capacity has the option to be billed at the simultaneous purchase and sale billing rate, or at the time-of-day billing rate.

7835.4013 AVERAGE RETAIL ENERGY RATE.

Subpart 1. **Method of billing.**

The utility must bill the qualifying facility for the energy supplied by the utility that exceeds the amount of energy supplied by the qualifying facility during each billing period according to the utility's applicable retail rate schedule.

Subp. 2. **Additional calculations for billing.**

When the energy generated by the qualifying facility exceeds that supplied by the utility during a billing period, the utility must compensate the qualifying facility for the excess energy at the average retail utility energy rate.

7835.4014 SIMULTANEOUS PURCHASE AND SALE BILLING RATE.

Subpart 1. **Method of billing.**

The qualifying facility must be billed for all energy and capacity it consumes during a billing period according to the utility's applicable retail rate schedule.

Subp. 2. **Compensation to qualifying facility.**

The utility must purchase all energy and capacity which is made available to it by the qualifying facility. At the option of the qualifying facility, its entire generation must be deemed to be made available to the utility. Compensation to the qualifying facility must be the sum of items A and B.

A. The energy component must be the appropriate system average incremental energy costs shown on schedule A; or if the generating utility has not filed schedule A, the energy component must be the energy rate of the retail rate schedule applicable to the qualifying facility, filed in lieu of schedules A and B; or if the nongenerating utility has not filed schedule A, the energy component must be the energy rate shown on schedule H.

B. If the qualifying facility provides firm power to the utility, the capacity component must be the utility's net annual avoided capacity cost per kilowatt-hour averaged over all hours shown on schedule B; or if the generating utility has not filed schedule B, the capacity component must be the demand charge per kilowatt, if any, of the retail rate schedule applicable to the qualifying facility, filed in lieu of schedules A and B, divided by the number of hours in the billing period; or if the nongenerating utility has not filed schedule B, the capacity component must be the capacity cost per kilowatt shown on schedule H, divided by the number of hours in the billing period. If the qualifying facility does not provide firm power to the utility, no capacity component may be included in the compensation paid to the qualifying facility.

7835.4015 TIME-OF-DAY PURCHASE RATES.

Subpart 1. **Method of billing.**

The qualifying facility must be billed for all energy and capacity it consumes during each billing period according to the utility's applicable retail rate schedule. Any utility rate-regulated by the commission may propose time-of-day retail rate tariffs which require qualifying facilities that choose to sell power on a time-of-day basis to also purchase power on a time-of-day basis.

Subp. 2. **Compensation to qualifying facility.**

The utility must purchase all energy and capacity which is made available to it by the qualifying facility. Compensation to the qualifying facility must be the sum of items A and B.

A. The energy component must be the appropriate on-peak and off-peak system incremental costs shown on schedule A; or if the generating utility has not filed schedule A, the energy component must be the energy rate of the retail rate schedule applicable to the qualifying facility, filed in lieu of schedules A and B; or if the nongenerating utility has not filed schedule A, the energy component must be the energy rate shown on schedule H.

B. If the qualifying facility provides firm power to the utility, the capacity component must be the utility's net annual avoided capacity cost per kilowatt-hour averaged over the on-peak hours as shown on schedule B; or if the generating utility has not filed schedule B, the capacity component must be the demand charge per kilowatt, if any, of the retail rate schedule applicable to the qualifying facility, filed in lieu of schedules A and B, divided by the number of on-peak hours in the billing period; or if the nongenerating utility has not filed schedule B, the capacity component must be the capacity cost per kilowatt shown on schedule H, divided by the number of on-peak hours in the billing period. The capacity component applies only to deliveries during on-peak hours. If the qualifying facility does not provide firm power to the utility, no capacity component may be included in the compensation paid to the qualifying facility.

7835.4016 INDIVIDUAL SYSTEM CAPACITY LIMITS.

Subpart 1. **Applicability.**

Individual system capacity limits are subject to the requirements in Minnesota Statutes, section 216B.164, subdivision 4c.

Subp. 2. **Usage history.**

A facility subject to capacity limits with less than 12 calendar months of actual electric usage or no demand metering available is subject to limits based on data for similarly situated customers combined with any actual data for the facility.

7835.4017 NET METERED FACILITY; BILL CREDITS.

Subpart 1. **Kilowatt-hour credit.**

A customer with a net metered facility can elect to be compensated for net input into the utility's system in the form of a kilowatt-hour credit on the customer's bill, subject to Minnesota Statutes, section 216B.164, subdivision 3a, and the following conditions:

A. the customer is not receiving a value of solar rate under Minnesota Statutes, section 216B.164, subdivision 10;

B. the customer is interconnected with a public utility; and

C. the net metered facility has a capacity of at least 40 kilowatt capacity but less than 1,000 kilowatt capacity.

Subp. 2. **Notification to customer.**

A public utility must notify the customer of the option to be compensated for net input in the form of a kilowatt-hour credit under subpart 1. The public utility must inform the customer that if the customer does not elect to be compensated for net input in the form of a kilowatt-hour credit on the bill, the customer will be compensated for the net input at the utility's avoided cost rate, as described in the utility's tariff for that customer class.

Subp. 3. **End-of-year net input.**

A public utility must compensate the customer, in the form of a payment, for any net input remaining at the end of the calendar year at the utility's avoided cost rate, as described in the utility's tariff for that class of customer.

7835.4018 AGGREGATION OF METERS.

A public utility must aggregate meters at the request of a customer as described in Minnesota Statutes, section 216B.164, subdivision 4a.

7835.4019 QUALIFYING FACILITIES OF 1,000 KILOWATT CAPACITY OR MORE.

A qualifying facility with capacity of 1,000 kilowatt capacity or more must negotiate a contract with the public utility to set the applicable rates for payments to the customer of avoided capacity and energy costs. Nothing in parts 7835.4010 to 7835.4015 prevents a utility from connecting qualifying facilities of greater than 1,000 kilowatt capacity under its avoided cost rates.

7835.4020 AMOUNT OF CAPACITY PAYMENTS; CONSIDERATIONS.

The qualifying facility which negotiates a contract under part 7835.4019 must be entitled to the full avoided capacity costs of the utility. The amount of capacity payments must be determined through consideration of:

A. the capacity factor of the qualifying facility;

B. the cost of the utility's avoidable capacity;

C. the length of the contract term;

D. reasonable scheduling of maintenance;

E. the willingness and ability of the qualifying facility to provide firm power during system emergencies;

F. the willingness and ability of the qualifying facility to allow the utility to dispatch its generated energy;

G. the willingness and ability of the qualifying facility to provide firm capacity during system peaks;

H. the sanctions for noncompliance with any contract term; and

I. the smaller capacity increments and the shorter lead times available when capacity is added from qualifying facilities.

7835.4021 UTILITY TREATMENT OF COSTS.

All purchases from qualifying facilities with capacity of less than 40 kilowatts and purchases of energy from qualifying facilities with capacity of 40 kilowatts or more must be considered an energy cost in calculating a utility's fuel adjustment clause.

7835.4022 LIMITING CUMULATIVE GENERATION.

A public utility requesting that the commission limit cumulative generation of net metered facilities under Minnesota Statutes, section 216B.164, subdivision 4b, must file its request with the commission under chapter 7829.

7835.4023 ALTERNATIVE TARIFF FOR VALUE OF SOLAR.

If a public utility has received commission approval of an alternative tariff for the value of solar under Minnesota Statutes, section 216B.164, subdivision 10, the tariff applies to new solar photovoltaic interconnections effective after the tariff approval date.

WHEELING AND EXCHANGE AGREEMENTS

7835.4100 WHEN REQUIRED.

For all qualifying facilities with capacity of 30 kilowatts or greater, the utility, at the qualifying facility's request or with its consent, must provide wheeling or exchange agreements whenever practicable to sell the qualifying facility's output to any other Minnesota utility that anticipates or plans generation expansion in the ensuing ten years. Parts 7835.4200 to 7835.4400 apply unless the qualifying facility and the utility to which it is interconnected agree otherwise.

7835.4200 INTERUTILITY PAYMENT; WHEELING.

The utility to which the qualifying facility is interconnected must pay any reasonable wheeling charges from other utilities arising from the sale of the qualifying facility's output.

7835.4300 INTERUTILITY PAYMENT; ENERGY AND CAPACITY.

Within 30 days of receipt, the utility ultimately receiving the qualifying facility's output must pay its resulting full avoided capacity and energy costs by remittance to the utility with which the qualifying facility is interconnected.

7835.4400 PAYMENT TO QUALIFYING FACILITY.

Within 15 days of receiving payment under part 7835.4300, the utility with which the qualifying facility is interconnected must send the qualifying facility the payment it has received less the total charges it has incurred under part 7835.4200 and its own reasonable wheeling costs.

DISPUTES

7835.4500 COMMISSION DETERMINATION.

In case of a dispute between a utility and a qualifying facility or an impasse in the negotiations between them, either party may request the commission to determine the issue. When the commission makes the determination, the burden of proof must be on the utility.

7835.4550 FEES AND COSTS.

In the order resolving the dispute, the commission shall require the prevailing party's reasonable costs, disbursements, and attorney's fees to be paid by the party against whom the issue or issues were adversely decided, except that a qualifying facility will be required to pay the costs, disbursements, and attorney's fees of the utility only if the commission finds that the claims of the qualifying facility have been made in bad faith or are a sham or frivolous.

NOTIFICATION TO CUSTOMERS

7835.4600 CONTENTS OF WRITTEN NOTICE.

Within 60 days following each annual filing required by parts 7835.0300 to 7835.1200, every utility must furnish written notice to each of its customers that the utility is obligated to interconnect with and purchase electricity from cogenerators and small power producers; that the utility is obligated to provide information to all interested persons free of charge upon request; and that any disputes over interconnection, sales, and purchases are subject to resolution by the commission upon complaint.

The notice must be in language and form approved by the commission.

7835.4700 AVAILABILITY OF INFORMATION.

Each utility must publish information that must be available to all interested persons free of charge upon request. Such information must include at least the following:

A. a statement of rates, terms, and conditions of interconnections;

B. a statement of technical requirements;

C. a sample contract containing the applicable terms and conditions;

D. pertinent rate schedules;

E. the title, address, and telephone number of the department of the utility to which inquiries should be directed; and

F. the statement: "The Minnesota Public Utilities Commission is available to resolve disputes upon written request," and the address and telephone number of the commission.

INTERCONNECTION CONTRACTS

7835.4750 INTERCONNECTION STANDARDS.

Before a customer signs the uniform statewide contract, a utility must distribute to that customer a copy of, or electronic link to, the commission's order establishing interconnection standards dated September 28, 2004, in docket number E-999/CI-01-1023, or to currently effective interconnection standards established by subsequent commission order.

7835.5900 EXISTING CONTRACTS.

Any existing interconnection contract executed between a utility and a qualifying facility with capacity of less than 40 kilowatts remains in force until terminated by mutual agreement of the parties or as otherwise specified in the contract.

7835.5950 RENEWABLE ENERGY CREDIT; OWNERSHIP.

Generators own all renewable energy credits unless:

A. other ownership is expressly provided for by a contract between a generator and a utility;

B. state law specifies a different outcome; or

C. specific commission orders or rules specify a different outcome.

7835.6000 CONTRACT LANGUAGE FLEXIBILITY.

Electric utilities organized as cooperatives may substitute "Cooperative" wherever "Utility" appears in the uniform statewide contract in part 7835.9910.

7835.6100 UNIFORM STATEWIDE CONTRACT.

The form of the uniform statewide contract for use between a utility and a qualifying facility having less than 40 kilowatts of capacity must be as shown in part 7835.9910.

7835.9910 UNIFORM STATEWIDE CONTRACT; FORM.

The form for the uniform statewide contract must be applied to all new and existing interconnections between a utility and cogeneration and small power production facilities having less than 1,000 kilowatts of capacity, except as described in part 7835.5900.

UNIFORM STATEWIDE CONTRACT FOR COGENERATION AND SMALL POWER PRODUCTION FACILITIES

THIS CONTRACT is entered into _____, ____, by _____ (hereafter called "Utility") and _____ _____ (hereafter called "QF").

RECITALS

The QF has installed electric generating facilities, consisting of _____ _____ _____ (Description of facilities), rated at ____ kilowatts of electricity, on property located at _____ _____.

The QF is prepared to generate electricity in parallel with the Utility.

The QF's electric generating facilities meet the requirements of the Minnesota Public Utilities Commission (hereafter called "Commission") rules on Cogeneration and Small Power Production and any technical standards for interconnection the Utility has established that are authorized by those rules.

The Utility is obligated under federal and Minnesota law to interconnect with the QF and to purchase electricity offered for sale by the QF.

A contract between the QF and the Utility is required by the Commission's rules.

AGREEMENTS

The QF and the Utility agree:

1. The Utility will sell electricity to the QF under the rate schedule in force for the class of customer to which the QF belongs.

2. The Cooperative Electric Association or Municipally Owned Electric Utility will buy electricity from the QF under the current rate schedule filed with the Commission. The QF elects the rate schedule category hereinafter indicated:

____ a. Average retail utility energy rate under part 7835.3300.

____ b. Simultaneous purchase and sale billing rate under part 7835.3400.

____ c. Time-of-day purchase rates under part 7835.3500.

A copy of the presently filed rate schedule is attached to this contract.

3. The Public Utility will buy electricity from the QF under the current rate schedule filed with the Commission. If the QF has less than 40 kilowatts capacity, the QF elects the rate schedule category hereinafter indicated:

____ a. Average retail utility energy rate under part 7835.4013.

____ b. Simultaneous purchase and sale billing rate under part 7835.4014.

____ c. Time-of-day purchase rates under part 7835.4015.

A copy of the presently filed rate schedule is attached to this contract.

4. The Public Utility will buy electricity from the QF under the current rate schedule filed with the Commission. If the QF is not a net metered facility and has at least 40 kilowatts capacity but less than 1,000 kilowatt capacity, the QF elects the rate schedule category hereinafter indicated:

____ a. Simultaneous purchase and sale billing rate under part 7835.4014.

____ b. Time-of-day purchase rates under part 7835.4015.

A copy of the presently filed rate schedule is attached to this contract.

5. The Public Utility will buy electricity from a net metered facility under the current rate schedule filed with the Commission or will compensate the facility in the form of a kilowatt-hour credit on the facility's energy bill. If the net metered facility has at least 40 kilowatts capacity but less than 1,000 kilowatts capacity, the QF elects the rate schedule category hereinafter indicated:

____ a. Kilowatt-hour energy credit on the customer's energy bill, carried forward and applied to subsequent energy bills, with an annual true-up under part 7835.4017.

____ b. Simultaneous purchase and sale billing rate under part 7835.4014.

____ c. Time-of-day purchase rates under part 7835.4015.

A copy of the presently filed rate schedule is attached to this contract.

6. The rates for sales and purchases of electricity may change over the time this contract is in force, due to actions of the Utility or of the Commission, and the QF and the Utility agree that sales and purchases will be made under the rates in effect each month during the time this contract is in force.

7. The Public Utility, Cooperative Electric Association, or Municipally Owned Electric Utility will compute the charges and payments for purchases and sales for each billing period. Any net credit to the QF, other than kilowatt-hour credits under clause 5, will be made under one of the following options as chosen by the QF:

____ a. Credit to the QF's account with the Utility.

____ b. Paid by check to the QF within 15 days of the billing date.

8. Renewable energy credits associated with generation from the facility are owned by:

_____

9. The QF must operate its electric generating facilities within any rules, regulations, and policies adopted by the Utility not prohibited by the Commission's rules on Cogeneration and Small Power

Production which provide reasonable technical connection and operating specifications for the QF. This agreement does not waive the QF's right to bring a dispute before the Commission as authorized by Minnesota Rules, part 7835.4500, and any other provision of the Commission's rules on Cogeneration and Small Power Production authorizing Commission resolution of a dispute.

10. The Utility's rules, regulations, and policies must conform to the Commission's rules on Cogeneration and Small Power Production.

11. The QF will operate its electric generating facilities so that they conform to the national, state, and local electric and safety codes, and will be responsible for the costs of conformance.

12. The QF is responsible for the actual, reasonable costs of interconnection which are estimated to be $_____. The QF will pay the Utility in this way:
_____
_____.

13. The QF will give the Utility reasonable access to its property and electric generating facilities if the configuration of those facilities does not permit disconnection or testing from the Utility's side of the interconnection. If the Utility enters the QF's property, the Utility will remain responsible for its personnel.

14. The Utility may stop providing electricity to the QF during a system emergency. The Utility will not discriminate against the QF when it stops providing electricity or when it resumes providing electricity.

15. The Utility may stop purchasing electricity from the QF when necessary for the Utility to construct, install, maintain, repair, replace, remove, investigate, or inspect any equipment or facilities within its electric system. The Utility will notify the QF before it stops purchasing electricity in this way: _____
_____.

16. The QF will keep in force liability insurance against personal or property damage due to the installation, interconnection, and operation of its electric generating facilities. The amount of insurance coverage will be $_____ (The amount must be consistent with the Commission's interconnection standards under Minnesota Rules, part 7835.4750).

17. This contract becomes effective as soon as it is signed by the QF and the Utility. This contract will remain in force until either the QF or the Utility gives written notice to the other that the contract is canceled. This contract will be canceled 30 days after notice is given.

18. This contract contains all the agreements made between the QF and the Utility except that this contract shall at all times be subject to all rules and orders issued by the Public Utilities Commission or other government agency having jurisdiction over the subject matter of this contract. The QF and the Utility are not responsible for any agreements other than those stated in this contract.

THE QF AND THE UTILITY HAVE READ THIS CONTRACT AND AGREE TO BE BOUND BY ITS TERMS. AS EVIDENCE OF THEIR AGREEMENT, THEY HAVE EACH SIGNED THIS CONTRACT BELOW ON THE DATE WRITTEN AT THE BEGINNING OF THIS CONTRACT.

_____

QF

By:_____

_____

UTILITY

By:_____

_____

(Title)

7835.9920 NONSTANDARD PROVISIONS.

A utility intending to implement provisions other than those included in the uniform statewide form of contract must file a request for authorization with the commission. The filing must conform with chapter 7829 and must identify all provisions the utility intends to use in the contract with a qualifying facility.

Document Accession #: 20161020-3063 Filed Date: 10/20/2016

157 FERC ¶ 61,044
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Norman C. Bay, Chairman;
Cheryl A. LaFleur, and Colette D. Honorable.

SunE B9 Holdings, LLC Docket Nos. EL16-58-000
QF15-793-001
QF15-794-001
QF15-795-001

ORDER GRANTING IN PART AND DENYING IN PART REQUEST FOR LIMITED WAIVER

(Issued October 20, 2016)

1. On April 22, 2016, SunE B9 Holdings, LLC (SunE B9) filed a petition for declaratory order (Petition) requesting a limited waiver of the small power production qualifying facility (QF) filing requirements set forth in section 292.203(a)(3) of the Commission's regulations[1] for a period of non-compliance from December 2010 until May 27, 2015.[2] The request for waiver is granted in part and denied in part, as discussed below.

I. Background

2. SunE B9 owns solar modules which are connected to eighteen 500 kW inverters, and which began operation in December 2010. On May 27, 2015, SunE B9 filed three Form 556 self-certifications, describing each respective QF as a solar electric generating facility and listing nine inverters at QF15-793-000, six inverters at QF15-794-000, and three inverters at QF15-795-000. All three Form 556 self-certifications listed the same geographic coordinates, and SunE B9 acknowledged that they are located within one mile of each other.

[1] 18 C.F.R. § 292.203(a)(3) (2016).

[2] On May 27, 2015, SunE B9 filed Form 556 ("Certification of Qualifying Facility (QF) Status for a Small Power Production or Cogeneration Facility") self-certifications in Docket Nos. QF15-793-000, QF15-794-000, and QF15-795-000. The Form 556 self-certifications state that the facilities were installed and began operation on December 22, 2010 for QF15-793-000; on December 20, 2010 for QF15-794-000; and December 28, 2010 for QF15-795-000.

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II. Request for Declaratory Order

3. SunE B9 explains that it has eighteen 500 kW inverters,[3] and further states that each inverter is physically separate and sells its output to Duke Energy Carolinas, LLC (Duke) under a separate power purchase agreement.[4] SunE B9 adds that it is a wholly-owned subsidiary of TerraForm Power, Inc., and that SunEdison, Inc. has an eighty-four percent indirect voting interest in TerraForm Power, Inc.

4. According to SunE B9, the inverters at issue have satisfied all of the requirements of the Public Utility Regulatory Policies Act of 1978 (PURPA)[5] during their entire operation, except for compliance with the filing requirement of section 292.203(a)(3).[6] SunE B9 argues that each inverter is exempt from the filing requirements of section 292.203(a)(3) because each inverter has a net power production capacity of less than 1 MW, and, pursuant to section 292.203(d),[7] facilities with a net power production capacity of 1 MW or less are exempt from the filing requirement of section 292.203(a)(3).[8]

5. However, SunE B9 is concerned that the Commission may apply the one-mile rule of section 292.204(a)(2)[9] and find that, because each inverter is within one mile of the

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[3] SunE B9 characterizes each inverter as a "Facility," such that it states that it has eighteen 500 kW "Facilities."

[4] Petition at 2.

[5] 16 U.S.C. §§ 796(17), 824a-3 (2012).

[6] 18 C.F.R. § 292.203(a)(3) (2016).

[7] *Id*. § 292.203(d) (2016).

[8] Petition at 3.

[9] Section 18 C.F.R. § 292.204(a) (2016), states:

(a) *Size of the facility—*

(1) *Maximum size*. Except as provided in paragraph (a)(4) of this section, the power production capacity of a facility for which qualification is sought, together with the power production capacity of any other small power production facilities that use the same energy resource, are owned by the same person(s) or its affiliates, and are located at the same site, may not exceed 80 megawatts.

(2) *Method of calculation*.

(continued ...)

others, none of the inverters are eligible for the filing exemption for QFs with a net capacity of 1 MW or less. SunE B9 therefore requests that, to the extent necessary, the Commission grant a limited waiver of the filing requirement of section 292.203(a)(3) such that each inverter will be treated as a QF from the date each inverter commenced operations until May 27, 2015.

6. SunE B9 characterizes the failure to timely submit notices of self-certification for the inverters as the result of a good faith error in interpreting an ambiguous regulation, asserting that the instructions for Form 556 and its Frequently Asked Questions for QFs do not adjust the facility size for affiliated facilities located within one mile in determining whether the less-than-1-MW filing exemption of section 292.203(d) is available to a QF.[10] SunE B9 states that the requested waiver is consistent with the Commission's precedent granting similar relief to other QFs.[11] SunE B9 asserts that the requested waiver will lighten the regulatory burden on QFs by providing most exemptions from the Federal Power Act (FPA), the Public Utility Holding Company Act of 2005,[12] and state laws provided to QFs under the Commission's regulations.[13]

7. SunE B9 states that it is not seeking waiver of FPA sections 205 and 206.[14] On April 22, 2016, SunE B9 made refunds to Duke and filed a refund report in Docket Nos. QF15-793-000 in the amount of $309,642.07, in QF15-794-000 in the amount of $207,455.46, and in QF15-795-000 in the amount of $101,381.39. On May 12, 2016, SunE B9 filed a revised refund report because certain principal amounts (i.e., initial

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(i) For purposes of this paragraph, facilities are considered to be located at the same site as the facility for which qualification is sought if they are located within one mile of the facility for which qualification is sought. . . .

(ii) For purposes of making the determination in clause (i), the distance between facilities shall be measured from the electrical generating equipment of a facility.

[10] Petition at 3 n.4.

[11] *Id*. at 4 (citing *Beaver Falls Mun. Auth.*, 149 FERC ¶ 61,108 (2014) (*Beaver Falls*); *OREG 1, Inc.,* 135 FERC ¶ 61,150 (2011), *reh'g denied,* 138 FERC ¶ 61,110 (2012) (*OREG 1*); *WM Renewable Energy, L.L.C.*, 130 FERC ¶ 61,268 (2010) (*WM Renewable*); *Ashland Windfarm, LLC*, 124 FERC ¶ 61,068 (2008) (*Ashland Windfarm*)).

[12] 42 U.S.C. § 16452 (2012).

[13] *Id*. at 4-5.

[14] *Id*. at 5 n.8.

monthly amounts paid by Duke for QF sales during the refund period) were incorrect. SunE B9 corrected the refunds in Docket Nos. QF15-793-000 to the amount of $307,140.47, in QF15-794-000 to the amount of $205,700.40, and in QF15-795-000 to the amount of $99,956.28.

III. Notice and Interventions

8. Notice of SunE B9's filing was published in the *Federal Register,* 81 Fed. Reg. 26,219 (2016), with interventions or protests due on or before May 25, 2016. On April 29, 2016, Duke filed a motion to intervene and comments.

9. Duke states that, in May 2008, Duke entered into power purchase agreements with SunE DEC1, LLC, a subsidiary of Sun Edison, Inc., to purchase power from 31 facilities that are interconnected to Duke's transmission/distribution system. Duke states that the facilities are comprised of the eighteen inverters owned by SunE B9 and thirteen inverters that are owned by SunE M5B Holdings, LLC (SunE M5B).[15]

10. Duke notes that, on April 22, 2016, the same day that SunE B9 filed the Petition, SunE B9 also filed a refund report with the Commission for refunds based on the time value of amounts received for QF sales to Duke for service provided between the date service commenced and May 27, 2015, the date that SunE B9 submitted its QF self-certification notices. Duke states that, on the same day, refund payments were made to and received by Duke that were consistent with the refund report.[16]

11. Duke states that the Petition does not include six inverters owned by SunE M5B that are also located within one mile of each other and that were also not submitted for QF self-certifications until May 27, 2015 although they had commenced operations in 2010. Duke argues that, by analogy to the rationale contained in the Petition in which SunE B9 states that it would make refunds to Duke pertaining to its eighteen inverters consistent with Commission precedent, such Commission precedent similarly applies to amounts Duke paid for QF sales pertaining to the six inverters owned by SunE M5B and that Duke should be paid refunds related to such amounts.[17]

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[15] Duke Comments at 1-2.

[16] *Id*. at 2-3.

[17] *Id*. at 3.

IV. Discussion

A. Procedural Matters

12. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2015), Duke's timely unopposed motion to intervene serves to make Duke a party to this proceeding.

B. Commission Determination

13. For many years, there was no express requirement in section 292.203 that a facility make a filing in order to establish QF status. However, in Order No. 671,[18] the Commission changed its regulations by adding the filing requirements for QF status contained in sections 292.203(a)(3) (for small power production facilities) and 292.203(b)(2) (for cogeneration facilities) of the Commission's regulations.[19] The Commission explained that it did not believe "that a facility should be able to claim QF status without having made any filing with this Commission."[20] Thus, our regulations require an owner or operator of a facility, whether existing or new, must, in addition to meeting other specified requirements, to file either a notice of self-certification, or an application for Commission certification that has been granted, in order to establish QF status for a generating facility larger than 1 MW.[21]

14. As noted above, the inverters began operation in December 2010 and SunE B9 filed three Form 556 self-certifications on May 27, 2015. The issue in this case is thus the intervening period and whether SunE B9's excuse for its failure to timely certify its inverters warrants waiver of the filing requirement for that period. We find that it does not, and we will deny SunE B9's requested waiver. SunE B9 has not justified its failure to comply with a filing requirement that has been present in the Commission's regulations since 2006.

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[18] *Revised Regulations Governing Small Power Production and Cogeneration Facilities,* Order No. 671, FERC Stats. & Regs. ¶ 31,203, *order on reh'g*, Order No. 671-A, FERC Stats. & Regs. ¶ 31,219 (2006).

[19] 18 C.F.R. §§ 292.203(a)(3), 292.203(b)(2) (2015). As with other changes in Commission regulations, this change was published in the *Federal Register*, 71 Fed. Reg. 7852 (2006).

[20] Order No. 671, FERC Stats. & Regs. ¶ 31,203 at P 81.

[21] 18 C.F.R. §§ 292.203(a)(3), 292.203(b)(2) (2016).

15. SunE B9 argues that each inverter is exempt from the filing requirements of section 292.203(a)(3) because each inverter has a net power production capacity of less than 1 MW, and, pursuant to section 292.203(d), facilities with a net power production capacity of 1 MW or less are exempt from the filing requirement of section 292.203(a)(3). However, SunE B9 states that it understands that the Commission may apply the one-mile rule of section 292.204(a)(2), thus viewing each inverter as having a 17.36 MW capacity and thus not eligible for the filing exemption for QFs with a net capacity of 1 MW or less.[22] SunE B9 requests that, if the Commission applies the one-mile rule of section 292.204(a)(2) here, and finds that because each inverter is within one mile of the others none of the inverters are eligible for the less-than-1-MW filing exemption of 292.203(d), the Commission grant a waiver of the filing requirement. SunE B9 states that it has complied with all "substantive" requirements for small power production QF status since the date the inverters went into service, and has operated under the assumption that they qualified as QFs since each commenced operations.[23]

16. The explanation that SunE B9 cites for failing to timely file is not persuasive. On May 27, 2015, SunE B9 filed self-certifications for three QFs, each of which has a net power production capacity in excess of 1 MW. Because each QF has a net power production capacity in excess of 1 MW, the filing exemption for QFs with a net capacity of 1 MW or less does not apply to any of these three QFs. Moreover, the one-mile rule of section 292.204(a)(2) is a size determination which the Commission has consistently applied generally to the regulations pursuant to PURPA,[24] and which applies here to determining the applicability of the less-than-1-MW exemption of section 292.203(d). As SunE B9 acknowledges, each of the eighteen inverters are within one-mile of the others, and therefore their combined net capacity is in excess of 1 MW. Therefore, the filing exemption for QFs with a net capacity of 1 MW or less does not apply here, and absent our granting the requested waiver, SunE B9's inverters would not be considered QFs from the time they became operational until May 27, 2015, when SunE B9 filed the notices of self-certification.

17. As the Commission has stated, "[t]he filing requirement is a substantive and important criterion for QF status, which was expressly adopted in Order No. 671 and

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[22] Petition at 2, 4.

[23] *Id*. at 2-3.

[24] *Windfarms, Ltd.*, 13 FERC ¶ 61,017, at 61,031 (1980) (finding that the Commission intended the one-mile rule to apply to the regulations implementing section 210(e) of PURPA, despite the fact that they do not expressly refer to the one-mile rule.)

must be followed."[25] Although SunE B9 argues that the failure to make the filing was due to an ambiguous regulation, the fact remains that, since the inverters began operation, they were out of compliance with the express requirements for QF status. In similar situations, the Commission has not been persuaded by claims that the facility met all other requirements for QF status because that argument improperly minimizes the importance of the filing requirement.[26]

18. SunE B9 cites several cases in support of the requested waiver.[27] We find that *Minwind I, Beaver Falls,* and *OREG 1* are particularly instructive. In each of those cases, the Commission denied waiver of the filing requirement, but nevertheless granted partial waiver to treat the facilities as QFs for the period that they were out of compliance.

19. Therefore, the Commission will grant SunE B9 the same partial waiver so that the inverters will be treated as QFs for the period that SunE B9's inverters operated out of compliance with the Commission's requirement that an owner of a small power production facility make a filing in order to certify as a QF, i.e., from December 2010, when the inverters began operation, until May 27, 2015, when the inverters self-certified as QFs, and as a consequence the inverters will qualify for most of the exemptions contained in sections 292.601 and 292.602 of the Commission's regulations,[28] excepting exemption from sections 205 and 206 of the FPA. Granting SunE B9 most of the exemptions from the FPA, the Public Utility Holding Company Act of 2005 and state laws, as provided in sections 292.601 and 292.602 of the regulations, which lighten the

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[25] *OREG 1, Inc.,* 135 FERC ¶ 61,150, at P 8.

[26] *See, e.g., Minwind I, LLC*, 149 FERC ¶ 61,109, at P 18 (2014) (*Minwind I*); *Beaver Falls,* 149 FERC ¶ 61,108 at P 25; *OREG 1*, *Inc.*, 135 FERC ¶ 61,150 at PP 8, 12.

[27] Petition at 4 n.7 (citing *Beaver Falls*, 149 FERC ¶ 61,108; *OREG 1, Inc.,* 135 FERC ¶ 61,150; *WM Renewable*, 130 FERC ¶ 61,268; *Ashland Windfarm*, 124 FERC ¶ 61,068). *Ashland Windfarm* involved atypical ownership of the petitioners' wind project companies. *Ashland Windfarm*, 124 FERC ¶ 61,068 at P 3. This case does not present a similar situation. SunE B9's reliance on *WM Renewable* is also misplaced. In *OREG 1*, the Commission stated that "*WM Renewable* was not consistent with the Commission's previously announced policy on dealing with late-filed QFs," and that the Commission has chosen "not to follow a decision inconsistent with its policy." *OREG 1*, *Inc.*, 135 FERC ¶ 61,150 at P 12.

[28] 18 C.F.R. §§ 292.601, 292.602 (2016).

regulatory burden on QFs, but denying exemption from sections 205 and 206 of the FPA, is consistent with the Commission's action in other cases.[29]

20. In *Prior Notice and Filing Requirements Under Part II of the Federal Power Act*, 64 FERC ¶ 61,139, *order on reh'g*, 65 FERC ¶ 61,081 (1993) (*Prior Notice*), the Commission clarified its refund remedy (for both cost-based and market-based rates) for the late filing of jurisdictional rates and agreements under section 205 of the FPA when waiver of the 60-day prior notice requirement is denied. With respect to sales for resale made without Commission authorization under FPA section 205, the Commission stated it would require the utility to refund to its customers: (1) the time value of the revenues collected, calculated pursuant to section 35.19a of the regulations,[30] for the entire period that the rate was collected without Commission authorization; and (2) all revenues resulting from the difference, if any, between the market-based rate and a cost-justified rate.[31] The second component of the two-part refund methodology does not typically apply to QFs because the Commission has previously indicated that a QF can use a substitute for the cost-justified rate, which may include the market-based rate or the avoided cost rate.[32] To the extent that there is no difference between the QF's rate collected and the market-based rate or the QF's rate collected and the avoided cost rate, the QF would not have a refund obligation under that part of the refund methodology. Here, the inverters have been selling pursuant to negotiated rates, satisfying the second component of the two-part refund methodology, but SunE B9 remains subject to the first component, e.g., the time-value refund obligation.

21. For any monies collected before the effective date, SunE B9 must refund the time value of the monies actually collected for the time period during which the rates were

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[29] *See Minwind I*, 149 FERC ¶ 61,109 at P 22; *Beaver Falls,* 149 FERC ¶ 61,108 at P 31; *OREG 1*, *Inc.*, 138 FERC ¶ 61,110 at P 16; *see also Iowa Hydro, LLC*, 146 FERC ¶ 61,207, at P 14 (2014); *accord CII Methane Management IV, LLC,* 148 FERC ¶ 61,229, at P 5 (2014); *LG&E-Westmoreland Southampton* (*Southampton*), 76 FERC ¶ 61,116, at 61,603-05 (1996), *order granting clarification and denying reh'g*, 83 FERC ¶ 61,182, at 61,752-53 (1998).

[30] 18 C.F.R. § 35.19a (2016).

[31] *Prior Notice*, 64 FERC ¶ 61,139 at 61,980.

[32] *Minwind I*, 149 FERC ¶ 61,109 at P 23; *see Trigen-St. Louis Energy Corp.*, 120 FERC ¶ 61,044, at P 32 (2007); *see also CII Methane Management IV, LLC,* 148 FERC ¶ 61,229, at P 4 (2014).

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charged without Commission authorization.[33] SunE B9 states that it is not seeking waiver of FPA sections 205 and 206.[34] As a result, on April 22, 2016, SunE B9 made refunds to Duke in the amount of $618,478.92 in Docket Nos. QF15-793-000, QF15-794-000 and QF15-795-000. On May 12, 2016, SunE B9 filed a revised refund report because certain principal amounts (i.e., initial monthly amounts paid by Duke for QF sales during the refund period) were incorrect. SunE B9 corrected the refunds to $612,797.15. Duke states that refund payments were made to and received by Duke and were consistent with the refund report.[35]

22. Finally, we find that Duke's comments related to SunE M5B are beyond the scope of this proceeding. The only issue presented in this case is whether SunE B9 should be granted a waiver of the filing requirements to establish QF status, not whether SunE M5B should be required to pay refunds.

The Commission orders:

The request for waiver is hereby granted in part and denied in part, as discussed in the body of this order.

By the Commission. Commissioner Honorable is concurring with a separate statement attached.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

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[33] *Minwind I*, 149 FERC ¶ 61,109 at P 24; *Florida Power & Light Co.*, 98 FERC ¶ 61,276 at 62,150-51, *reh'g denied*, 99 FERC ¶ 61,320 (2002).

[34] Petition at 5 n. 8.

[35] *Id*. at 2-3.

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UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

SunE B9 Holdings, LLC

Docket No. EL16-58-000
QF15-793-001
QF15-794-001
QF15-795-001

(Issued October 20, 2016)

HONORABLE, Commissioner, *concurring*:

In today's order, the Commission directed SunE B9 to refund the time value of the revenues collected during periods of SunE B9's noncompliance with the Commission's QF requirements, consistent with the Commission's long-standing policy. I support that policy because it encourages timely compliance, but write separately to express concern with how time value refunds are calculated for generation resources.

Although I agree with the Commission's decision today, I believe it is appropriate to revisit how we establish a refund floor for time value refunds. The Commission establishes a refund floor for time value refunds to protect entities by ensuring that they will not be forced to operate at a loss. For generation resources, the Commission determines this floor by considering only variable operation and maintenance (O&M) costs. Thus, a generation resource is responsible to make time value refunds only to the extent such refunds would not recoup the resource's variable O&M costs. The Commission has taken a different approach in establishing refund floors for non-generation resources. In Opinion No. 540, the Commission explained the reason for the different approaches:[1]

> The Commission distinguished between the time value refund methodology that applies in cases involving power sales . . . in which the utility typically incurs substantial fuel and other O&M costs that vary with the amount of energy produced or transmitted, and the time value refund methodology that has been used and accepted in numerous generator interconnection and transmission line ownership cases, where the costs incurred are sunk investment in the transmission system or fixed O&M costs that do not vary depending on the

[1] *Opinion No. 540,* 153 FERC ¶ 61,185, at P57 (2015).

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amount of energy produced or transmitted . . .

As a result, the Commission's time value refund methodology does not distinguish between thermal and non-thermal generation resources (e.g., renewable resources), even though, as discussed below, non-thermal generation resources have levels of variable and fixed O&M costs more akin to that of interconnection customers and transmission owners.

The levels of variable and fixed O&M costs for renewable resources, including the solar resources at issue here, are more similar to that of interconnection customers and transmission owners than thermal generation resources. For example, according to a 2013 EIA report, a photovoltaic resource generally has $0.00/MWh variable O&M costs and $27.75/kW-year fixed O&M costs.[2] In contrast, a conventional natural gas combined-cycle generator generally has $3.60/MWh variable O&M costs (excluding fuel) and $13.17/kW-year fixed O&M costs. Adding fuel to the natural gas-fired generator's variable O&M costs, which the Commission uses to determine a refund floor, would further increase the variable O&M figure.[3]

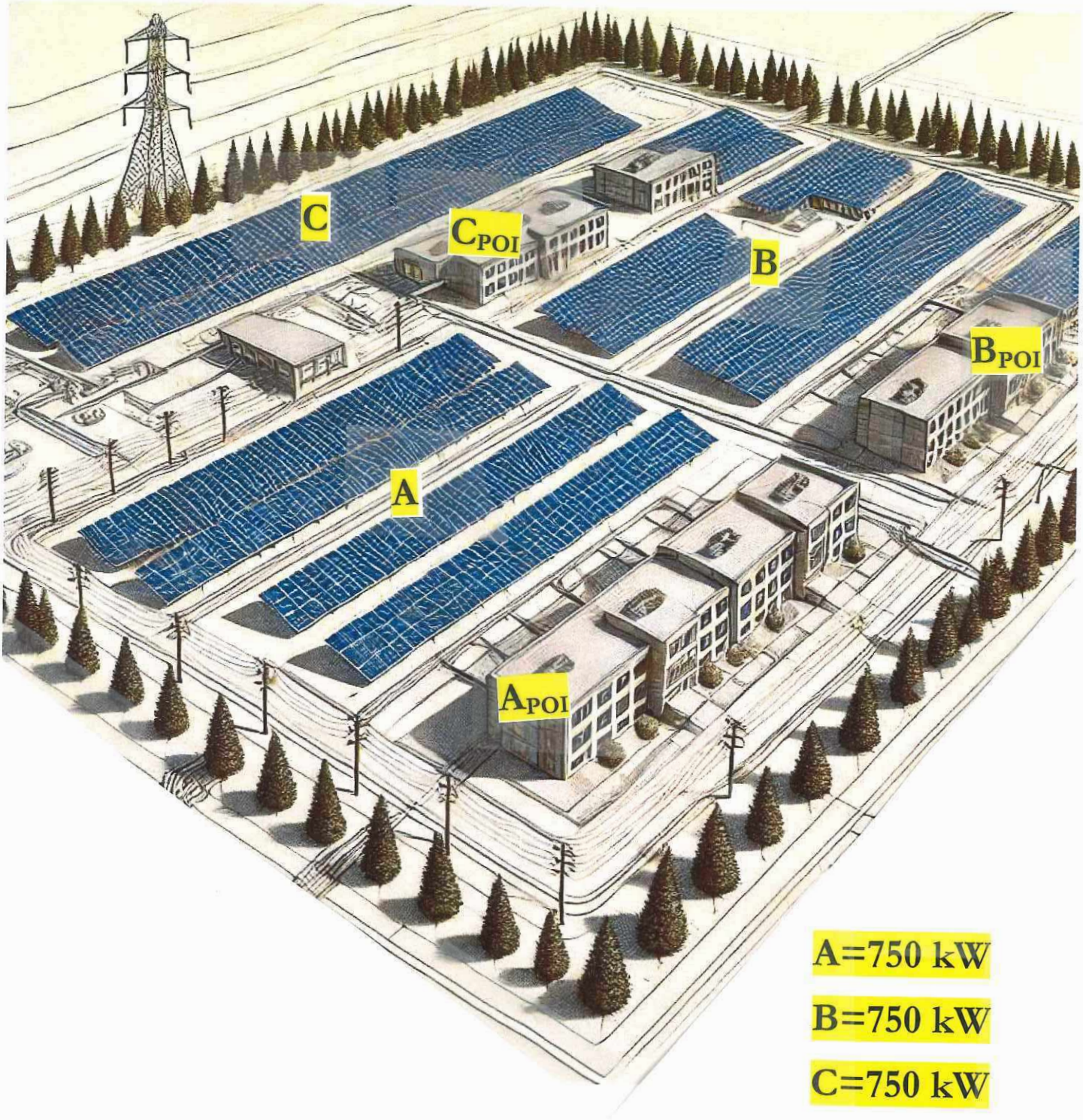
Although not specifically at issue today, I remain sensitive to concerns that our policies with respect to generation resources might result in entities with higher fixed costs having to pay larger refunds because of the nature of their cost structure and not their conduct. Our industry has seen tremendous evolution and renewable generation resources have been reliably supplying electricity for many years. We must continually evaluate our policies to ensure they keep pace with changes in the markets we regulate. The Commission has properly considered fixed costs in the transmission context. I believe we should stand ready to apply those principles to similarly situated entities.

Accordingly, I respectfully concur.

Colette D. Honorable
Commissioner

[2] *See* https://www.eia.gov/forecasts/capitalcost/pdf/updated_capcost.pdf at Table 1.

[3] *See* https://www.eia.gov/forecasts/aeo/pdf/electricity_generation.pdf at Table 1b.


C
CPOI
B
BPOI
A
APOI
A=750 kW
B=750 kW
C=750 kW
QF=2.25 MW

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February 18, 2025

Consumer Affairs Office
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101

Re: PUC Docket Number: E002/M-24-389

Ladies and Gentlemen:

We hereby respectfully submit the following Comments on behalf of United Health Group, in accordance with "Notice of Comment Period Issued: December 15, 2025 [sic.]" and PUC Docket Number: E002/M-24-389.

Thank you for your attention to this matter.

Sincerely,

By: _____
Farid Khosravi, Esq.
Minnesota License Number: 0387642

Attachment #1

Draft UHG Comments

E002/M-24-389 MN PUC Xcel Energy Petition – UHG Comments

Introduction:

Northern States Power Company, doing business as Xcel Energy ("Xcel Energy" and ("Xcel"), filed with the Minnesota Public Utilities Commission ("MN PUC" and "Commission") on November 20, 2024, submitted their Petition MN PUC Docket No. E002/M-24-389 - *Petition of Northern States Power Co. d/b/a Xcel Energy to Revise Its Net Metering Tariffs to Apply to Qualifying Facilities Up to 5 MW* ("Xcel Energy Petition").[1]

The Xcel Energy Petition describes in part that the proposed changes "apply to Distributed Energy Resource (DER) Qualifying Facilities (QFs) up to and including 5 megawatts (MW). The current net metering tariff applies for QFs less than 1 MW." (*See*, Xcel Energy Petition at 1). The changes, however, generally apply only to **Sale to Company After Customer Self-Use Rate Code A51/A52.** For example, the Xcel Energy Petition includes changes to:

- **Tariff Sheet 9-8.2: These changes are conforming edits that recognize that the net metering Rate Codes A51 and A52 can apply to QFs up to 5MW**

In other, the proposed changes (to increase the size eligibility) would not apply to other Net Metering tariffs such as "**Monthly Net Metering Rate Code A53/A54. Such a change to Monthly Net Metering would encourage sustainability development in the State of Minnesota as described herein.**

The UHG Comments are respectfully submitted in accordance with the "Notice of Comment Period Issued: December 18, 2025 [sic]" in the subject Docket E002/M-24-389.

UnitedHealth Group ("UnitedHealth Group" and "UHG") Background:

UnitedHealth Group is a health care and well-being company made up of a diverse team around the world working to help build a modern, high-performing health system through improved access, affordability, outcomes and experiences. Optum combines clinical expertise, technology and data to empower people, partners and providers with the guidance and tools they need to achieve better health. UnitedHealthcare offers a full range of health benefits, enabling affordable coverage, simplifying the health care experience and delivering access to high-quality care.

Optum Solar Project:

At UnitedHealth Group, our mission calls us, our values guide us, and our culture connects us as we seek to improve care for the consumers we are privileged to serve and their communities**.** Sustainability is a foundation to fulfill our mission and deepen our societal impact by improving the health and well-being of the people we serve. UHG has made several public commitments related to sustainability, including 1) achieving

[1] pursuant to Minn. R. 7829.1300 and Minn. R. 7829.0700 and Minn. Stat. § 216.17, subd. 3 et seq.

E002/M-24-389 MN PUC Xcel Energy Petition – UHG Comments

operational net-zero emissions by 2035, 2) achieving 60% reduction in scope 1 and scope 2 emissions by 2030, and 3) investing and sourcing 100% of our global electricity demand with renewable sources by 2030. Achieving these commitments requires aggressive decarbonization efforts, with renewable energy serving as a key driver of progress. At our Optum Headquarters in Minnesota we have installed a solar array on the roof of the Optum Campus parking garage. This solar investment supports our decarbonization strategy by offsetting ~50% of the site's energy use while also enhancing the employee experience on campus. Additionally, it serves as a tangible demonstration of clean energy adoption, helping to accelerate the transition to a renewable-powered grid.

Topic(s) Open for Comment:

- Should the Commission approve Xcel's requested changes to the net metering tariff to allow the tariff to apply to Qualifying Facilities up to and including 5 MW?
- Should the Commission approve the requested variance to Minn. R. 7829.3200?
- Are there other issues or concerns related to this matter?

Commission; Notice of Comment Period Issued December 18, 2025

Recommendation:

While the subject Case indicates that Xcel Energy's intent is "*to Revise Its Net Metering to Apply to Qualifying Facilities Up to 5 MW*" (Xcel Energy Petition), the filing is generally specific to Rate Codes A51/52 only.

For instance, the Xcel Energy Petition states that:

- **Tariff Sheet 9-3:** This is the first tariff sheet for Rate Codes A51/A52 and raises the size of QFs that can seek to use these Rate Codes from "less than 1,000 kW" to "not greater than 5,000 kW." (*See,* Xcel Petition at 4 and 5; *See also,* red-lined Rate Sheets at Attachment B pages 1-7.)

The Xcel Petition does not, however, include "**Monthly Net Metering Rate Code A53/A54"** which otherwise would encourage greater development of renewable resources for healthcare, schools[2], municipalities and other interested stakeholders and serve to advance the sustainability and environmental goals for the state of Minnesota. For example, Minnesota Executive Order 19-27 ("MN Executive Order") related to Minnesota's government operations (*See* **Attachment A**) opining that:

[2] The University of Minnesota, Twin Cities ("University") 2023 Climate Action Plan (CAP) builds on the University's history of leadership and identifies actions to eliminate emissions from campus activities at a pace consistent with limiting warming to 1.5°C. The University will reduce emissions by 60% over the next decade compared to 2019 levels and will become carbon neutral by 2050 (University's Climate Action Plan went before the Board of Regents in May of 2023. (*See,* Twin Cities Climate Action Plan 2023 Online.pdf)

E002/M-24-389 MN PUC Xcel Energy Petition – UHG Comments

> to run our government in more sustainable ways helps Minnesotans by improving the environment, controlling unnecessary waste of natural resources and public funds, and spurring innovation… the subject Executive Order goes on to add that "[t]hese measures save taxpayer dollars through avoided costs, increased efficiencies, more resilient facilities, and a stronger economy.

(*See*, Executive Order at 1)

Furthermore, in describing "**Sustainability Goals**" the Executive Order states that "Cabinet Agencies will improve their operational practices to achieve the following Sustainability Goals" and that includes "**Greenhouse Gas Emissions**: 30% reduction of greenhouse gas emissions by 2025 relative to a 2005 calculated baseline." (*Id.* at 1 and 2).

As such, to advance industry investment in sustainable development, UHG's recommendation to the Commission is to direct Xcel Energy to: 1) increase the eligible size limit from less than 1 MW to 5 MW for Monthly Net metering under "**Monthly Net Metering Rate Code A53/A54"** and related tariffs as Xcel Energy has requested under **A51/A52;** or 2) make clear that for "**Monthly Net Metering Rate Code A53/A54"** each interconnection point that is less than 1 MW stands alone and cannot be aggregated (without the customers consent) or considered cumulative to limit a customer's participation under the respective Tariff.

Conclusion:

The recommendations of UHG as provided herein supports the Optum Solar Project, but also supports future sustainability, environmental needs and encourages greater development of renewable resources in Minnesota impacting interested stakeholders (many that have significant sustainability goals) that includes healthcare, schools, municipalities.

Accordingly, in order to advance sustainability and environmental goals for the state of Minnesota, UHG recommends that the Commission direct Xcel Energy to: 1) increase the eligible size limit from less than 1 MW to 5 MW for Monthly Net metering under "**Monthly Net Metering Rate Code A53/A54"** and related tariffs as Xcel Energy has requested under **A51/A52;** or 2) make clear that for "**Monthly Net Metering Rate Code A53/A54"** each interconnection point that is less than 1 MW stands alone and cannot be aggregated (without the customers consent) or considered cumulative to limit a customer's participation under the respective Tariff.

CERTIFICATE OF SERVICE

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

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

xx electronic filing

DOCKET NO. E002/C-25-435

Dated this 13th day of March 2026

/s/

Victor Barreiro
Regulatory Administrator

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2	Matthew	Brodin	mbrodin@allete.com	Minnesota Power		30 West Superior Street Duluth MN, 55802 United States	Electronic Service		No	C-25-435
3	Mike	Bull	mike.bull@state.mn.us		Public Utilities Commission	121 7th Place East, Suite 350 St. Paul MN, 55101 United States	Electronic Service		Yes	C-25-435
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9	John	Farrell	jfarrell@ilsr.org	Institute for Local Self-Reliance		2720 E. 22nd St Institute for Local Self-Reliance Minneapolis MN, 55406 United States	Electronic Service		No	C-25-435
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12	Adam	Heinen	aheinen@dakotaelectric.com	Dakota Electric Association		4300 220th St W Farmington MN, 55024 United States	Electronic Service		No	C-25-435
13	Michael	Hoppe	lu23@ibew23.org	Local Union 23, I.B.E.W.		445 Etna Street Ste. 61 St. Paul MN,	Electronic Service		No	C-25-435

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20	Christine	Marquis	regulatory.records@xcelenergy.com	Xcel Energy		414 Nicollet Mall MN1180-07-MCA Minneapolis MN, 55401 United States	Electronic Service		No	C-25-435
21	Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP		33 South Sixth St Ste 4200 Minneapolis MN, 55402 United States	Electronic Service		No	C-25-435
22	David	Niles	david.niles@avantenergy.com	Minnesota Municipal Power Agency		220 South Sixth Street Suite 1300 Minneapolis MN, 55402 United States	Electronic Service		No	C-25-435
23	Carol A.	Overland	overland@legalectric.org	Legalectric - Overland Law Office		1110 West Avenue Red Wing MN, 55066 United States	Electronic Service		No	C-25-435
24	Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	1400 BRM Tower 445 Minnesota St St. Paul MN, 55101-2131 United States	Electronic Service		Yes	C-25-435
25	Kevin	Reuther	kreuther@mncenter.org	MN Center for Environmental Advocacy		26 E Exchange St, Ste 206 St. Paul MN, 55101-1667 United States	Electronic Service		No	C-25-435

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29	Joseph	Windler	jwindler@winthrop.com	Winthrop & Weinstine		225 South Sixth Street, Suite 3500 Minneapolis MN, 55402 United States	Electronic Service		No	C-25-435
30	Kurt	Zimmerman	kwz@ibew160.org	Local Union #160, IBEW		2909 Anthony Ln St Anthony Village MN, 55418-3238 United States	Electronic Service		No	C-25-435
31	Patrick	Zomer	pzomer@cozen.com	Cozen O'Connor		150 S. 5th Street, #1200 Minneapolis MN, 55402 United States	Electronic Service		No	C-25-435