414 Nicollet Mall
Minneapolis, MN 55401

August 18, 2025

—Via Electronic Filing—

Mike Bull
Acting Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101

RE: COMMENTS
POSSIBLE AMENDMENT TO RULES RELATING TO DEFINITION OF "CAPACITY"
DOCKET NOS. E002, E111, E017, E015/CI-24-200 AND E999/R-25-86

Dear Mr. Bull:

Northern States Power Company, doing business as Xcel Energy, submits the enclosed Comments per the Commission's July 7, 2025, Request for Comments.

We have electronically filed this document with the Minnesota Public Utilities Commission, and copies have been served on the participants on the attached service list. Please contact Taige Tople at taige.d.tople@xcelenergy.com or me at brian.t.monson@xcelenergy.com if you have any questions regarding this filing.

Sincerely,

/s/

BRIAN MONSON
MANAGER, DISTRIBUTION REGULATORY STRATEGY

Enclosures
cc: Service Lists

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

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

IN THE MATTER OF POSSIBLE AMENDMENT TO RULES RELATING TO THE DEFINITION OF "CAPACITY", MINN. R. 7835.0100, SUBP. 4

DOCKET NOS. E002, E111, E017, E015/CI-24-200 AND E999/R-25-86

COMMENTS

INTRODUCTION

Northern States Power Company, doing business as Xcel Energy, submits these Comments per the Commission's July 7, 2025, Request for Comments.

The Minnesota Public Utilities Commission has requested comments on a possible rule amendment to the definition of "capacity." The Request includes the Commission's current working draft of the possible amendment, as shown in redline below:

> **7835.0100 DEFINITIONS**
> **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. <u>"Capacity," as defined under Minn. Stat. § 216B.164, subd. 2a (c), for purposes of eligibility for net-metering in Minn. Stat. § 216B.164, subd. 3(d), is determined by, and measured at, the qualifying facility's inverter or a power control system or supplemental device that controls production at the qualifying facility before the net-metered customer's load.</u>

As explained in further detail below, Xcel Energy respectfully suggests some "friendly" edits to the new proposed rule language consistent with the edits being proposed by the "Utility Group".

I. BACKGROUND TO THIS PROCEEDING

This rulemaking was initiated by the Commission in its January 23, 2025 "Order Initiating Rulemaking Proceeding" in Docket No. E002/, E111, E017, E015/CI-24-200. Docket No. 24-200 was opened by the Commission in its May 22, 2024 Order in Docket Nos. E111/M-18-711 and E999/CI-16-521, relating to provisions in Dakota Electric's Technical Specifications Manual (TSM), which in context only applied to net metering for systems less than 40 kW. The Commission's Order in Docket No. 24-200 followed extensive comments filed by several participants and a Commission hearing on the matter.

The Commission's Order noted that the thrust of the disagreement among the parties is whether capacity is measured according to the maximum number of kilowatts (nameplate rating or nameplate capacity) the facility is capable of producing, or rather, if capacity is measured by the output generated regardless of the facility's nameplate rating. In other words, a 40-kilowatt (kW) nameplate facility has the capacity to generate a maximum of 40 kW. But the output of a facility with a nameplate rating greater than 40 kW could be limited by technology (such as an inverter or power control system) to limit the facility's output to no more than 40 kW, making it a de facto 40-kW facility when operated.

The January 2025 Order noted that the parties disagreed on whether the existing definitions of capacity in statute and rule account for limiting technology, and in particular, stakeholders representing the interests of generation facilities advocated for amending the rule for clarity. Because the definition of "capacity" affects the level of compensation a facility is entitled to receive from a utility for its net input into the utility's system, the parties claimed that an unreasonable definition could result in compensation levels inconsistent with amounts authorized under the statute.

II. PROPOSED REVISION TO DEFINITION OF CAPACITY IN THE COMMISSION'S RULES

The origin of the issues here is related to Dakota Electric's TSM, which had proposed a methodology for determining whether a DER system had an aggregate Nameplate Rating of less than 40 kW for purposes of determining eligibility for its net metering program. The Commission is contemplating a modification to its rules under Minn. R. 7835 so as to clarify the definition of "capacity." However, it is important not to, in addition, limit the application of the term to the type of net metering that is only available for systems less than 40 kW. The Commission Rules at Minn. R. 7835 apply the term "capacity" not only for purposes of determining eligibility for net metering for systems less than 40 kW, but also for several other situations, such as: determining eligibility for other types of net metering for systems up to 1,000 kW, determining a path forward for systems 1,000 kW or larger, determining whether standby charges may be assessed depending on system size, and applying the 120% rule for systems 40 kW or larger. Given that this is now a rulemaking process, and the issues in Minn. R. 7835 go beyond the discrete issues that are only specific to systems less than 40 kW, Xcel Energy recommends that the language of the proposed rule change be modified to apply a consistent definition of "capacity" for all purposes under Minn. R. 7835 as it currently applies.

Based on the above, Xcel Energy respectfully proposes "friendly" edits to the proposed rule language consistent with that being proposed by the "Utility Group". Our incremental edits to the suggested draft amendment in the Commission Request are shown in redline below:

> 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~~ interconnection between a qualifying facility and a utility's electric system. "Capacity," as defined under Minn. Stat. § 216B.164, subd. 2a (c), for purposes of ~~eligibility for net-metering in~~ Minn. Stat. § 216B.164~~, subd. 3(d),~~ is determined by~~, and measured at,~~ the qualifying facility's nameplate rating, inverter settings, or a power control system or supplemental device that controls production ~~at~~ of the qualifying facility before the net-metered customer's load.

In clean format, this is:

> 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 interconnection between a qualifying facility and a utility's electric system. "Capacity," as defined under Minn. Stat. § 216B.164, subd. 2a (c), for purposes of Minn. Stat. § 216B.164 is determined by the qualifying facility's nameplate rating, inverter settings, or a power control system or supplemental device that controls production of the qualifying facility before the net-metered customer's load.

The high level reasons for these suggested changes are addressed in the Utility Comments. Further, the rules under Minn. R. 7835 implement Minn. Stat. 216B.164. This statute has many provisions that are triggered based on the size of the system, not just the 40 kW threshold in subd. 3(d). The Company details these other provisions that include system size specifications below:

> **Minn. Stat. § 216B.164, subd. 3(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. …
>
> **Minn. Stat. § 216B.164, subd. 3(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).
>
> **Minn. Stat. § 216B.164, subd. 3(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.
>
> **Minn. Stat. § 216B.164, subd. 3a(a):**
> … 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. …

Minn. Stat. § 216B.164, subd. 3a(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.

Minn. Stat. § 216B.164, subd. 4:
(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.
…

Minn. Stat. § 216B.164, 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.

Similarly, the rules at Minn. R. 7835 also have different requirements depending on the size of the system. The Company details these more specifically. These include the following:

Minn. R. 7835.2600, 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.

Minn. R. 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. **[Sections .3300 to .3600 below are intentionally further indented to show that they are tied to Section .3150]**

Minn. R. 7835.3300 (Average Retail Utility Energy Rate), Subp. 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.

Minn. R. 7835.3400 (Simultaneous Purchase and Sale Billing Rate), Subp. 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.

Minn. R. 7835.3500 (Time-Of-Day Purchase Rates) Subp. 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.

Minn. R. 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.

Minn. R. 7835.4010 (INTERCONNECTION WITH PUBLIC UTILITY).
Parts 7835.4011 to 7835.4023 apply to interconnections between a qualifying facility and a public utility. **[Sections .4012 to .4019 below are intentionally further indented to show that they are tied to Section .4010]**

Minn. R. 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.

Minn. R. 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.

Minn. R. 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.

The Uniform Statewide Contract (at Minn. R. 7835.9910) also uses the term "capacity" to address situations where a QF has capacity less than 40 kW (par. 3) or at least 40 kW but less than 1,000 kW (pars. 4 and 5).

If the Commission is contemplating adopting a revision to the definition of capacity to be applied to determine if a system is less than 40 kW, then it should apply that same definition for purposes of determining if the system is less than 100 kW (for purposes of applying standby charges under the rules), for purposes of applying the 120% rule for systems of at least 40 kW but less than 1,000 kW. It would make sense to apply the same methodology for determining the size of a QF in these different scenarios as set forth in the rules. Limiting the new definition to only apply to the determination of whether the system is under 40 kW could lead to confusion and future arguments that a different methodology should be employed for determining system sizes in these other scenarios. There is no fundamental public policy that establishes why a different methodology should be employed in these different scenarios. Therefore, the Company believes that the proposed definition should be revised to apply more uniformly to these different scenarios, consistent with our proposed edits above.

We also note that the term "net-metered" in the Commission's proposed rule revision is not necessary and therefore our suggested edits recommend deleting this term. Further, the use of "net-metering" would create some confusion when the capacity definition is applied to systems exceeding 1 MW (or exceeding the 120% rule) as these facilities are not eligible for the statutory net metering, yet the same capacity definition should be used in determining the size for these facilities. The same definition of capacity should apply under this rule regardless of whether the customer participates in the net metering under this rule.

III. General Support for Clarifying the Definition of Capacity

The parties' different interpretations of the word "capacity" in the prior rounds of comments in Docket Nos. 24-200, 18-711 and 16-521 demonstrate a need that the Commission further clarify the meaning of this word for purposes of applying the rules at Minn. R. 7835. Xcel Energy, consistent with its prior filings in Docket No 24-200, re-iterates its positions taken there. Because the record of the current docket does not include the filings from this prior docket, there is some repetition below of points previously made by Xcel Energy in the prior docket.

A. Clarifying Scope of Comments

During discussions among the participants following the issuance of the Notice of Comment period in Docket No. 24-200, there was a lack of agreement on how batteries in conjunction with a PV system should be counted for purposes of net metering. In that proceeding, the two scenarios described below were discussed As the Company understands it, only the first listed scenario below was properly within the scope of allowed comments under the Commission's Notice, while other stakeholders may want to also engage in discussion and seek Commission action on the second scenario below:

1. Whether, or to what extent, can on-site load not associated with actually creating the energy be used to off-set the capacity output of the PV generation for purposes of net-metering.
2. Whether, or to what extent, can battery storage be used to off-set the capacity output of the PV generation for purposes of net metering. This includes whether anticipated battery charging and exports can together be allowed to reduce the overall production capacity of the DER system.

The Commission has sent the battery + PV issue to the DGWG for further record development. Ordering Point 7 in the Commission's April 15, 2024 ORDER in Docket No. E999/CI-16-521 states:

> *The Commission directs the DGWG to explore if and how battery storage systems should be evaluated under the MN DIP. Topics to discuss would include: should the battery storage and DER generation be studied on a combined basis in the interconnection process, and whether or not net-metered DER plus storage applications should be treated differently under the MN DIP than non-exporting DER plus storage applications."*

Also, how system capacity sizes are determined under MN DIP likely will generally align with how system capacity sizes are determined for purposes of net metering. The first DGWG subgroup session on this issue took place on March 14, 2025, but the work has not been completed. The slides associated with this workgroup session were filed by Staff on March 17, 2025 in Docket No. 16-521. The most recent DGWG subgroup session on this issue took place on July 31, 2025 and the issues still have not been resolved.. The DGWG subgroup sessions are ongoing.

During the prior discussions, MnSEIA appeared to be relying on the DC Circuit decision in SEIA v FERC (59 F.4th 1287 (DC Cir 2023) to support its position that anticipated battery charging and exports can together be allowed to reduce the overall production capacity of the DER system. This DC Circuit court decision does not alter the Commission's Order that this issue needs to first be addressed in the DGWG or enlarge the scope of Comments under the Request. Most importantly, this DC Circuit decision has been vacated by the US Supreme Court (based on the US Supreme Court no longer authorizing use of the Chevron doctrine). (See, *Edison Electric v. FERC*, 2024 WL 3259657, order of July 2, 2024).

Further, there is no current real-fact case on this battery+PV issue before the Commission, so there is no need to address it now. Even the DC Circuit has held in abeyance other real-world challenges to qualifying facility (QF) status related to the appellate court decision until that appeal is resolved.[1] Since the DC Circuit is holding real-world issues on battery+PV in abeyance, we do not believe this rulemaking process should try to address a theoretical challenge. The Company below engages in the substantive discussion of scenario number 1 described above.

B. HOW MINN. STAT. §216B.164 ALIGNS WITH PURPA

A purpose of the Minnesota Statute at issue, Minn. Stat. § 216B.164, is to implement PURPA. This can be referred to as the Minnesota PURPA Implementation Statute. The statute is even specific that the FERC regulations under PURPA "… *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*…."

The repeated language in Minn. Stat. §216B.164, when it uses the term capacity, associates it with the capacity of a "qualifying facility". (See, for example, Minn. Stat. § 216B.164 Subds. 3, 3a, 4, and 6). The term "qualifying facility" is well known as a FERC term as part of its implementation of PURPA. The provisions of Minn. Stat. §216B.164 do not indicate any different definition of this term than what was defined by FERC in implementing PURPA. Under this statute, "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.*"

While the Minnesota statutory definition of capacity applies to a "distributed generation facility", the FERC definition of a QF is still pertinent because of the extensive references to QFs in Minn. Stat. § 216B.164 and Minn. R. 7835. All distribution QFs include one or more distributed generation facilities.

FERC considers the "power production capacity" of a QF to be the maximum net output of the facility that can be safely and reliably achieved under the most favorable anticipated design conditions (*See* FERC Form 556 at p. 10, provided as Attachment A). In particular, we draw attention to Row 7b at the capacity calculation table on that page 10 of FERC Form 556 which states:

> **7b** Parasitic station power used at the facility to run equipment which is necessary and integral to the power production process (boiler feed

[1] See, e.g., *Gallatin Power Partners LLC*, 176 FERC ¶ 61,120 (Trident Solar 1 project), *reh'g denied*, 177 FERC ¶ 62,048 (2021), *petition for review filed sub nom. NorthWestern Corp. v. FERC* (D.C. Cir. Dec. 21, 2021) (No. 21-1269, orders of January 18, 2022 and July 13, 2023); *Gallatin Power Partners LLC*, 177 FERC ¶ 61,181 (2021) (Shields Valley project), *reh'g denied*, 178 FERC ¶ 62,088 (2022), *petition for review filed sub nom. NorthWestern Corp. v. FERC* (D.C. Cir. Apr. 6, 2022) (No. 22- 1055, orders of May 2, 2022 and July 13, 2023).

> pumps, fans/blowers, office or maintenance buildings directly related to the operation of the power generating facility, etc.). If this facility includes nonpower production processes (for instance, power consumed by a cogeneration facility's thermal host), do not include any power consumed by the non-power production activities in your reported parasitic station power.

We emphasize the last several lines of the above excerpt, which show that nonpower production processes are not to be netted out of the calculation of the net electric power capacity calculation for the facility.

FERC has specified that "*[t]he net output of the facility is its send out after subtraction of the power used to operate auxiliary equipment in the facility necessary for power generation (such as pumps, blowers, fuel preparation machinery, and exciters) and for other essential electricity uses in the facility from the gross generator output.*" *Occidental Geothermal, Inc.*, 17 FERC ¶ 61,231 at 61,445 (1981). *See also Conn. Valley Elec. Co. v. Wheelabrator Claremont Co.*, 82 FERC ¶ 61,116 (1998). In addition, line losses from the QF to the point of interconnection are also deducted to determine net output. *See id.*

1. *Determination of What is a QF Single Site*

The FERC analysis in SunE B9 Holdings, (157 FERC ¶ 61,044, issued October 20, 2016, and attached as Attachment B) is informative on how to measure the capacity of a QF at a single site. A single QF can be composed of several distributed generation facilities. The specific context of this Order was whether a number of PV inverters owned by affiliated developers that were within one mile of each other should be aggregated for purposes of determining whether they are considered to be a single QF when applying the FERC one-mile rule. SunE characterized its position as having eighteen physically separate 500 kW "Facilities." If the QF is larger than 1 MW capacity, it needs to file a FERC Form 556 Self-Certification. SunE argued that it was exempt from the requirement to file the FERC Form 556 because each inverter had a net power production capacity of less than 1 MW. (18 CFR §292.203(d)(1) exempts from the FERC Form 556 filing requirement any facility with a "net power production capacity" of 1 MW or less.) In determining the capacity, the Order confirmed that the capacity of a qualifying facility is measured by using the "net power production capacity." FERC also decided that the aggregate of these capacity numbers within one mile is used to determine the overall size of the single QF composed of all of these inverters that were within one mile. The FERC determined that the QF was larger than 1 MW, and therefore, SunE needed to file the 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 the SunE case reflects an application of FERC's so-called "one-mile" rule, pursuant to which all small power production facilities that are owned by the same entity and located within one mile of each other are considered to be a single small power production facility for purposes of QF certification. Under the one-mile rule, the net capacities of all the small power production facilities that are owned by the same entity (or affiliate), use the same energy resource, and are located within one mile of each other are aggregated to determine the "total" facility's capacity on small power production facilities. The one-mile rule functions as a definitive rule such that FERC automatically deems any facilities inside the one-mile periphery as a single QF at a single site. In 2020, FERC adjusted its policy to address concerns that the one-mile rule is arbitrary and leads to developers gaming the rule by placing components of the same facility outside the one mile range. *See Qualifying Facility Rates and Requirements Implementation Issues Under the Public Utility Regulatory Policies Act of 1978*, Order No. 872, 85 FR 54638 (Sep. 2, 2020), 172 FERC ¶ 61,041 (2020); 18 C.F.R. § 292.204(a)(2) (2024).

Specifically, FERC ruled that it would apply a rebuttable presumption that small power production facilities that are owned by the same or affiliated entities and that are located more than one mile but less than 10 miles apart are not part of the same small power production facility. The presumption that facilities located within 10 miles, but more than one mile apart, of each other are not part of a single small power production facility can be rebutted by evidence that, among other things, the facilities in question have: 1) evidence of shared control systems; (2) common permitting and land leasing; and (3) shared step-up transformers.

The Company provides the diagram in Attachment C to help explain this concept. For this diagram, assume that there are three different points of interconnection. The solar facilities of A, B, and C are each 750 kW, and are connected to different buildings, and the points of interconnection for each are in three different buildings. Yet, all three systems are owned by the same entity, and all three systems are within 1 mile of each other. All three systems are powered by the same energy source – the sun. In applying the FERC one-mile rule to this example to determine the size of a QF, there would be one QF and its size would be 2.25 MW (3 x 750 kW). These facilities would not be eligible for our current net metering tariff which has a 1 MW QF cap.

The Commission's June 25 2025 Order in Docket No. 24-389 is clear on the application of the one-mile rule.[2] The Order, at page 3, specifically noted that United Health Group argued that DER facilities owned by the same customer that are within one mile of each other should not have their capacity aggregated for determining the QF size for purposes of determining eligibility for Minnesota statutory net metering.[3] At page 4, the Order noted that Xcel Energy had argued that United Health Group's suggested approach would unfairly reduce monthly electricity payments from larger net metering customers, thereby shifting costs onto other ratepayers and also argued that aggregation of net metered facilities within one mile of each other to determine the size of the QF for purposes of eligibility for Minnesota statutory net metering is in the public interest and consistent with Federal Energy Regulatory Commission guidance on determining the size of a QF.

The Order clearly rejected the suggested approach from United Health Group and stated: "Xcel [Energy] argued that United Health Group's recommended net metering tariff changes would unfairly reduce monthly electricity payments from larger net metering customers, thereby shifting costs onto other ratepayers. Xcel [Energy] also argued that aggregation of net metered facilities within one mile of each other is in the public interest and consistent with Federal Energy Regulatory Commission guidance." (June 2025 Order, page 4). The Commission has properly applied the one-mile rule and the Order did not change this.

2. *Wide Application Resulting From Determined Capacity of QFs*

Given specific deference under Minn. Stat. § 216B.164 to PURPA and FERC, and given that this statute refers to the capacity of the QF for purposes of applying net metering and other purposes, the FERC approach to determining the capacity of an individual distributed generation facility under its FERC Form 556 should apply here. The Commission's rules under Minn. R. 7835 should continue to be interpreted consistent with continuing to align with the FERC implementation on the meaning of a QF. And, while the SunE FERC Order applied this approach for determining whether the size of a QF was at or over 1 MW, this same approach should be used for determining whether the size of the QF is under 40 kW, or for any other purposes for

[2] Please note that as of the date of the present filing there is a Petition for Reconsideration pending in Docket No. 24-389, filed on July 15, 2025.

[3] Succinctly stated, the Minnesota statutory net metering is generally reflected in the Xcel Energy net metering rate codes A50 to A56. Rate Code A50 is at tariff sheet 9-2, and consistent with Minn. Stat. § 216B.164, Subd. 3, pars. b and d. This Rate Code A50 is available to QFs less than 40 kW and provides payment for excess production on a monthly basis at the "Average Retail Energy Rate". Rate Codes A51-A56 are available for QFs less than 1,000 kW consistent with Minn. Stat. § 216B.164, Subd. 3, par. b and Subd. 3a. Rate Codes A51-A56 provide payment for excess production at an avoided cost rate based on either 15-minute net metering (Rate Codes A51/A52 at tariff sheet 9-3), monthly net metering (Rate Codes A53/A54 at tariff sheet 9-4), or annual net metering (Rate Codes A55/A56 at tariff sheet 9-4.2).

determining the capacity of a QF for PURPA or net metering purposes. The capacity of a QF should be measured in the same consistent way for all PURPA and net metering purposes.

We also generally use this approach for engineering review under MN DIP. One such situation is where a QF has several inverters within one mile, such as at a campus-like environment with several buildings, but each connect through separate retail meters. In this situation, the Company will issue separate interconnection agreements for each inverter that is associated with its separate retail meter. However, having separate interconnection agreements does not impact how the capacity of the QF is determined for PURPA or net metering purposes.

The rules under Minn. R. 7835 were developed by the Commission to implement and apply the Minnesota PURPA Implementation Statute. The Commission current rule at Minn. R. 7835.0100, subp. 4, defines capacity as: *"… 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*." In Docket No. 24-200, various parties failed to recognize this rule's salient language, which refers to "capacity" as "the ***capability to produce***, transmit or deliver electric energy . . .." (***Emphasis added***). They also ignored the Commission's explication in its Statement of Need and Reasonableness that "… capacity is, in effect, the amount of ***electricity actually produced***."[4] Hence, these commenters disregarded the fact that a distributed solar facility's capacity is determined by its production capability, not by how much power is "exported" beyond the customer premise to the grid. Because the statute defines capacity as its *alternating current*, a generation facility's capacity is properly tied to the production capability of its inverters.

The Commission's definition of capacity, as explained by the Commission, is controlling and unchanged by the term "point of common coupling". The Commission defines Point of Common Coupling under Minn. R. 7835.0100, Subp. 17a, as: "*the point where the qualifying facility's generation system, **including the point of generator output**, is connected to the utility's electric power grid*." (***emphasis added***) Various parties in Docket No. 24-200 arrived at the incorrect conclusion that based on the definition of point of common coupling that the statutory "*point of interconnection*" is the point beyond the point of generator output and is instead where the excess energy generation is sent to the utility after the on-site load has been subtracted from generator output. To the contrary, the Commission defined the point of common coupling as "*including the point of generator output*." The common thread

[4] Commission Statement of Need and Reasonableness, Docket No. E999/R-13-729 (December 29, 2014), p 4 (***emphasis added***).

through all these Commission definitions is that a generation facility's capacity is its AC production or output, not the facility's export to the grid after on-site load.

Various parties in Docket No. 24-200 also mentioned the stated purpose of the Minnesota PURPA Implementation Statute, which is: "*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, they do not give any weight to the last nine words of the above sentence: "*consistent with protection of the ratepayers and the public.*" The proposed revision to the rule, with the suggested friendly modification above, better protects the ratepayers and the public by avoiding unnecessary cross-subsidies and arriving at a definition that can be implemented.

Of note, the Department in Docket No. 24-200 acknowledged that the "net metered" facility, under the Minnesota PURPA Implementation Statute, and a QF under both this statute and PURPA, have the same definition of capacity. We agree with the Department that the definition of the capacity of a "net metered facility" is the same as that for a QF where there is a single DG system. A "net metered facility" when it is a single DG system is a subset of what qualifies as a QF. Further, as shown in the excerpts above from Minn. R. 7835, the provisions for net metered facilities are at Minn. R. 7835.4017 and thus are QFs per the provisions of Minn. R. 7835.4010.

Basically, 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 such facility has a capacity of at least 40 kW but less than 1000 kW, it is eligible to certain rates for compensation and other requirements such as in some circumstances being subject to the 120 percent rule (Minn. Stat. §216B.164, Subd. 4c).

The inter-relatedness of what the term "capacity" means for QFs and "net metered facility" as a subset of QFs is apparent in the fact that neither the applicable statutes nor rules suggest any difference between the two. State statutes equate the capacity determination for each in Subd 3 (pars. e and f) and in Subd 3a (par. b). The Uniform Statewide Contract under Minn. R. 7835.9910 (to which net metering applies) refers to the customer as being a QF. See Attachments D and E, which contain the Minnesota PURPA Implementation Statute and Minn. R. 7835, and show in highlights these two terms. State law requires symmetry between the Minnesota PURPA Implementing Statute and PURPA on this issue.

Those participating in net metering need to sign the Commission's Uniform Statewide Contract at Minn. R. 7835.9910. This contract form has a blank space towards the beginning where the parties need to enter the "rating" of the QF system that is subject to the Uniform Statewide Contract. Under MN DIP 1.1.5, the Uniform Statewide Contract replaces the need to have a signed Minnesota Distributed Energy Resource Interconnection Agreement (MN DIA) if the system is 20 kW or less in DER capacity. Accordingly, many QFs which are a single DG have signed the Uniform Statewide Contract with a single set capacity size that applies to both the MN DIP size and net metering size. Further, there are many systems that require having both a signed Uniform Statewide Contract and a MN DIA. Accordingly, those QFs participating in net metering need to have their capacity determined with a consistent methodology to other QFs.

Changing the definition of capacity from how this term has been implemented thus far could have other cascading impacts. For example, the Company has consistently been using "net power production capacity" for determining the size of QF of a single DG system for purposes of applying net metering tariffs; for purposes of determining eligibility for the $15,000 cost sharing program as specified on tariff sheet 10-81.4 for MN DIP applications which are 40 kW AC or less; and, for purposes of determining whether a MN DIP application should be in the "priority" or "general" queue as specified on tariff sheet 10-81.5 where the priority queue is for applications up to 40 kW. Under this approach, it is assumed that other than load needed to power the inverters, there is no other on-site load offset for purposes of determining the net power production capacity. The Company also uses this methodology for required reporting under Minn. R. 7835.1300, .1400, and .1500 and other reporting. Here are some additional possible cascading impacts if the Commission were to now re-interpret the definition of capacity in a way different than proposed in the rule revision:

- What qualifies for the distributed solar energy standards (DSES), which has a limit of 10 MW capacity under Minn. Stat. §26B.1691, Subd. 2h? Changing the interpretation of capacity would enlarge the effective size of projects eligible to be counted towards the DSES, upsetting the legislative intent by allowing systems larger than those contemplated by the legislation to be counted towards compliance with the DSES.
- What is the Commission's authority to review major facilities with a capacity of 50 MW or more under Minn. Stat. §216B.24? By changing the interpretation of capacity, the Commission would not have the ability to review those projects that, with the new interpretation, would no longer be determined to be above the 50 MW threshold but which would have met this threshold under the existing long-standing interpretation.
- What is the Commission's authority to review Large Energy Facilities of 50 MW or more under Minn. Stat. §216B.2421 and Minn. Stat. §216B.243? Similar

> to the above, by changing the interpretation of capacity, the Commission might not have the ability to review those projects that, with the new interpretation, would no longer be determined to be above the 50 MW threshold.

IV. FURTHER COMMENT ON WORDING IN THE REQUEST

The Request includes the following wording:

> The Commission has requested comments on whether to measure capacity based on a qualifying facility's (QFs) electric energy production, rather than its nameplate capacity. The Commission's Request states that under Minn. Stat. § 216B.164, subd. 3(d), a QF with less than 40-kilowatt (kW) capacity may elect to be compensated for its net input into a utility's system at the average retail utility energy rate. The Commission's Request states that the scope of this rulemaking proceeding is to consider amending the rule to clarify that a QF with a nameplate rating of 40 kW capacity or more may be compensated for up to 39 kW of net input into the utility's system at the rate allowed under Minn. Stat. § 216B.164, subd. 3(d).

The Company has concerns regarding this wording in the Request. In theory, as written, this request comments on whether a system much larger than 40 kW can be compensated up to 39 kW at the Average Retail Energy Rate. For example, this could allow a 100 kW QF system essentially on paper to be broken up into a 39 kW system and a 61 kW system, with net input from the 39 kW system being compensated at the Average Retail Energy Rate. This is far different from and much broader than the scope of prior discussions in this docket. Further, the size of a QF is determined by applying the FERC one-mile rule and is the aggregate of all distributed generation facilities owned by the same owner (or its affiliates) powered by the same energy source (such as the sun) within one mile of each other. This does not allow for the bifurcation of a QF system on the same site to be broken down into discrete QFs. There is no support for the fundamental shift in how to measure the size of a QF as discussed in the above narrative in the Commission's Request.

V. ADVISORY COMMITTEE

The Request also asks for comment on whether the Commission should appoint an advisory committee under Minn. Stat. § 14.101 to comment on the possible rules. And, the Request asks for expressions of interest to serve on such a committee if it is to be formed. Xcel Energy does not currently see a need for an Advisory Committee.

However, if one is formed, Xcel Energy requests the opportunity to have one or more representatives assigned to this Advisory Committee.

CONCLUSION

The Company respectfully requests that the Commission adopt the "friendly" amendment to the proposed rule revision so that it reads as follows:

> 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 interconnection between a qualifying facility and a utility's electric system. "Capacity," as defined under Minn. Stat. § 216B.164, subd. 2a (c), for purposes of Minn. Stat. § 216B.164 is determined by the qualifying facility's nameplate rating, inverter settings, or a power control system or supplemental device that controls production of the qualifying facility before the net-metered customer's load.

Dated: August 18, 2025

Northern States Power Company

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, DC

OMB Control # 1902-0075
Expiration 01/31/2027

Form 556 Certification of Qualifying Facility (QF) Status for a Small Power Production or Cogeneration Facility

General

Questions about completing this form should be sent to Form556@ferc.gov. Information about the Commission's QF program, answers to frequently asked questions about QF requirements or completing this form, and contact information for QF program staff are available at the Commission's QF website, www.ferc.gov/QF. The Commission's QF website also provides links to the Commission's QF regulations (18 C.F.R. § 131.80 and Part 292), as well as other statutes and orders pertaining to the Commission's QF program.

Title 18, U.S.C. 1001 makes it a crime for any person knowingly and willingly to make to any Agency or Department of the United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction.

Who Must File

Certification:

Any applicant seeking QF status for a generating facility that has a net power production capacity (as determined in lines 7a through 7g below) greater than 1 MW must file a self-certification or an application for Commission certification of QF status, which includes a properly completed Form 556. Any applicant seeking QF status for a generating facility with a net power production capacity 1 MW or less is exempt from the certification requirement and is therefore not required to complete or file a Form 556. *See* 18 C.F.R. § 292.203. This includes any applicant seeking small power production QF status for a generating facility that, together with any affiliated small power production QFs that use the same energy resource and are within one mile of the filing facility, has a net power production capacity 1 MW or less.

Recertification:

A QF must file a recertification whenever the qualifying facility "fails to conform with any material facts or representations presented … in its submittals to the Commission." 18 C.F.R. § 292.207(f).

Among other possible changes in material facts that would necessitate recertification, a small power production QF is required to recertify to update item 8a due to a change at an affiliated facility(ies) one mile or less from its electrical generating equipment. A small power production QF is *not* required to recertify due to a change at an affiliated facility(ies) listed in item 8a that is more than one mile but less than 10 miles away from its electrical generating equipment, unless that change also impacts any other entries on the Form 556.

How to Complete the Form 556

This form is intended to be completed by responding to the items in the order they are presented, according to the instructions given. If you need to back-track, you may need to clear certain responses before you will be allowed to change other responses made previously in the form. If you experience problems, click on the nearest help button ( ) for assistance, or contact Commission staff at Form556@ferc.gov.

Certain lines in this form will be automatically calculated based on responses to previous lines, with the relevant formulas shown. You must respond to all of the previous lines within a section before the results of an automatically calculated field will be displayed. If you disagree with the results of any automatic calculation on this form, contact Commission staff at Form556@ferc.gov to discuss the discrepancy before filing.

You must complete all lines in this form unless instructed otherwise. Do not alter this form or save this form in a different format. Incomplete or altered forms, or forms saved in formats other than PDF, will be rejected.

How to File a Completed Form 556

Applicants are required to file their Form 556 electronically through the Commission's eFiling website (see instructions on page 3). By filing electronically, you will reduce your filing burden, save paper resources, save postage or courier charges, help keep Commission expenses to a minimum, and receive a much faster confirmation (via an email containing the docket number assigned to your facility) that the Commission has received your filing.

If you are simultaneously filing both a waiver request and a Form 556 as part of an application for Commission certification, see the "Waiver Requests" section on page 4 for more information on how to file.

Paperwork Reduction Act Notice

This form is approved by the Office of Management and Budget. Compliance with the information requirements established by the FERC Form 556 is required to obtain or maintain status as a QF. *See* 18 C.F.R. § 131.80 and Part 292. An agency may not penalize a person for not complying with a collection of information unless it displays a currently valid OMB control number.

The estimated total burden for completing the FERC Form 556, including gathering and reporting information, is as follows: 1.5 hours for self-certifications of facilities of 1 MW or less; 1.5 hours for self-certifications of a cogeneration facility over 1 MW; 50 hours for applications for Commission certification of a cogeneration facility; 3.5 hours for self-certifications of small power producers over 1 MW and less than a mile or more than 10 miles from affiliated small power production QFs that use the same energy resource; 56 hours for an application for Commission certification of a small power production facility over 1 MW and less than a mile or more than 10 miles from affiliated small power production QFs that use the same energy resource; 9.5 hours for self-certifications of small power producers over 1 MW with affiliated small power production QFs more than one but less than 10 miles that use the same energy resource; 62 hours for an application for Commission certification of a small power production facility over 1 MW with affiliated small power production QFs more than one but less than 10 miles that use the same energy resource.

Send comments regarding this burden estimate or any aspect of this collection of information, including suggestions for reducing this burden, to the following: Information Clearance Officer, Office of the Executive Director (ED-32), Federal Energy Regulatory Commission, 888 First Street N.E., Washington, DC 20426 (DataClearance@ferc.gov); and Desk Officer for FERC, Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 through www.reginfo.gov/public/do/PRAMain. Include FERC-556 and the Control No. 1902-0075 in any correspondence.

Filing Fee

No filing fee is required if you are submitting a self-certification or self-recertification of your facility as a QF pursuant to 18 C.F.R. § 292.207(a).

A filing fee is required if you are filing either of the following:

(1) an application for Commission certification or recertification of your facility as a QF pursuant to 18 C.F.R. § 292.207(b), or
(2) a petition for declaratory order granting waiver pursuant to 18 C.F.R. §§ 292.204(a)(3) and/or 292.205(c).

The current fees for applications for Commission certifications and petitions for declaratory order can be found by visiting the Commission's QF website at www.ferc.gov/QF and clicking the Filing Fees link.

You will be prompted to submit your filing fee, if applicable, during the electronic filing process described on page 3.

Electronic Filing (eFiling)

To electronically file your Form 556, visit the Commission's QF website at www.ferc.gov/QF and click the eFiling link.

If you are eFiling your first document, you will need to register with your name, email address, mailing address, and phone number. If you are registering on behalf of an employer, then you will also need to provide the employer name, alternate contact name, alternate contact phone number and and alternate contact email.

Once you are registered, log in to eFiling with your registered email address and the password that you created at registration. Follow the instructions. When prompted, select one of the following QF-related filing types, as appropriate, from the Electric or General filing category.

Filing category	Filing Type as listed in eFiling	Description
Electric	(Fee) Application for Commission Cert. as Cogeneration QF	Use to submit an application for Commission certification or Commission recertification of a cogeneration facility as a QF.
	(Fee) Application for Commission Cert. as Small Power QF	Use to submit an application for Commission certification or Commission recertification of a small power production facility as a QF.
	Self-Certification Notice (QF, EG, FC)	Use to submit a notice of self-certification of your facility (cogeneration or small power production) as a QF.
	Self-Recertification of Qualifying Facility (QF)	Use to submit a notice of self-recertification of your facility (cogeneration or small power production) as a QF.
	Self-Recertification of Qualifying Facility (QF) (Supplement or Correction)	Use to correct or supplement a Form 556 that was submitted with errors or omissions, or for which Commission staff has requested additional information. Do *not* use this filing type to report new changes to a facility or its ownership; rather, use a self-recertification or Commission recertification to report such changes.
General	(Fee) Petition for Declaratory Order (not under FPA Part 1)	Use to submit a petition for declaratory order granting a waiver of Commission QF regulations pursuant to 18 C.F.R. §§ 292.204(a)(3) and/or 292.205(c). A Form 556 is not required for a petition for declaratory order unless Commission recertification is being requested as part of the petition.

You will be prompted to submit your filing fee, if applicable, during the electronic submission process. Filing fees can be paid by check or money order via ACH Credit transfer, wire payment, courier, or mail.

During the eFiling process, you will be prompted to select your file(s) for upload from your computer.

Required Notice to Utilities and State Regulatory Authorities

Pursuant to 18 C.F.R. § 292.207(a)(ii), you must provide a copy of your self-certification or request for Commission certification to the utilities with which the facility will interconnect and/or transact, as well as to the State regulatory authorities of the states in which your facility and those utilities reside. Links to information about the regulatory authorities in various states can be found by visiting the Commission's QF website at www.ferc.gov/QF and clicking the Notice Requirements link.

What to Expect From the Commission After You File

An applicant filing a Form 556 electronically will receive an email message acknowledging receipt of the filing and showing the docket number assigned to the filing. Such email is typically sent within one business day, but may be delayed pending confirmation by the Secretary of the Commission of the contents of the filing.

An applicant submitting a self-certification of QF status should expect to receive no documents from the Commission, other than the electronic acknowledgement of receipt described above. Consistent with its name, a self-certification is a certification *by the applicant itself* that the facility meets the relevant requirements for QF status, and does not involve a determination by the Commission as to the status of the facility. An acknowledgement of receipt of a self-certification, in particular, does not represent a determination by the Commission with regard to the QF status of the facility. An applicant self-certifying may, however, receive a rejection, revocation or deficiency letter if its application is found, during periodic compliance reviews, not to comply with the relevant requirements.

An applicant submitting a request for Commission certification will receive an order either granting or denying certification of QF status, or a letter requesting additional information or rejecting the application. Pursuant to 18 C.F.R. § 292.207(b)(3), the Commission must act on an application for Commission certification within 90 days of the later of the filing date of the application or the filing date of a supplement, amendment or other change to the application.

Protests to the Filing

Pursuant to 18 C.F.R. § 292.207, an interested party has 30 days from the date of the filing of a self-certification or self-recertification to intervene or file a protest. Protests may be made to an initial certification (both self-certification and application for Commission certification) filed on or after December 31, 2020, but only to a recertification (both self-recertification and application for Commission recertification) that makes substantive changes to the existing certification and that is filed on or after December 31, 2020, as described in Order No. 872 (accessible from the Commission's QF website at www.ferc.gov/QF). Substantive changes that may be subject to a protest may include, for example, a change in electrical generating equipment that increases power production capacity by the greater of 1 MW or 5% of the previously certified capacity of the QF, or a change in ownership in which an owner increases its equity interest by at least 10% from the equity interest previously reported. The protestor must concurrently serve a copy of such filing pursuant to 18 C.F.R. § 385.2011. Any response to a protest must be filed on or before 30 days from the date of filing of that protest.

Waiver Requests

18 C.F.R. § 292.204(a)(3) allows an applicant to request a waiver to modify the method of calculation pursuant to 18 C.F.R. § 292.204(a)(2) to determine if two facilities are considered to be located at the same site, for good cause. 18 C.F.R. § 292.205(c) allows an applicant to request waiver of the requirements of 18 C.F.R. §§ 292.205(a) and (b) for operating and efficiency upon a showing that the facility will produce significant energy savings. A request for waiver of these requirements must be submitted as a petition for declaratory order, with the appropriate filing fee for a petition for declaratory order. Applicants requesting Commission recertification as part of a request for waiver of one of these requirements should electronically submit their completed Form 556 along with their petition for declaratory order, rather than filing their Form 556 as a separate request for Commission recertification. Only the filing fee for the petition for declaratory order must be paid to cover both the waiver request and the request for recertification *if such requests are made simultaneously*.

18 C.F.R. § 292.203(d)(2) allows an applicant to request a waiver of the Form 556 filing requirements, for good cause. Applicants filing a petition for declaratory order requesting a waiver under 18 C.F.R. § 292.203(d)(2) do not need to complete or submit a Form 556 with their petition.

Geographic Coordinates

Items 3c and 8a of the Form 556 require you to report your facility's (and certain neighboring facilities') geographic coordinates (latitude and longitude). Geographic coordinates may be obtained from several different sources. You can find links to online services that show latitude and longitude coordinates on online maps by visiting the Commission's QF webpage at www.ferc.gov/QF. You may also be able to obtain your geographic coordinates from a GPS device, Google Earth (available free at http://earth.google.com), a property survey, various engineering or construction drawings, a property deed, or a municipal or county map showing property lines.

Filing Privileged Data or Critical Energy Infrastructure Information in a Form 556

The Commission's regulations provide procedures for applicants to either (1) request that any information submitted with a Form 556 be given privileged treatment because the information is exempt from the mandatory public disclosure requirements of the Freedom of Information Act, 5 U.S.C. § 552, and should be withheld from public disclosure; or (2) identify any documents containing critical energy infrastructure information (CEII) as defined in 18 C.F.R. § 388.113 that should not be made public.

If you are seeking privileged treatment or CEII status for any data in your Form 556, then you must follow the procedures in 18 C.F.R. § 388.112. See www.ferc.gov/help/filing-guide/file-ceii.asp for more information.

Among other things (see 18 C.F.R. § 388.112 for other requirements), applicants seeking privileged treatment or CEII status for data submitted in a Form 556 must prepare and file both (1) a complete version of the Form 556 (containing the privileged and/or CEII data), and (2) a public version of the Form 556 (with the privileged and/or CEII data redacted). Applicants preparing and filing these different versions of their Form 556 must indicate below the security designation of this version of their document. If you are *not* seeking privileged treatment or CEII status for any of your Form 556 data, then you should not respond to any of the items on this page.

☐ **Non-Public**: Applicant is seeking privileged treatment and/or CEII status for data contained in the Form 556 lines indicated below. This non-public version of the applicant's Form 556 contains all data, including the data that is redacted in the (separate) public version of the applicant's Form 556.
☐ **Public (redacted)**: Applicant is seeking privileged treatment and/or CEII status for data contained in the Form 556 lines indicated below. This public version of the applicants's Form 556 contains all data except for data from the lines indicated below, which has been redacted.
Privileged: Indicate below which lines of your form contain data for which you are seeking privileged treatment
Critical Energy Infrastructure Information (CEII): Indicate below which lines of your form contain data for which you are seeking CEII status

The eFiling process described on page 3 will allow you to identify which versions of the electronic documents you submit are public, privileged and/or CEII. The filenames for such documents should begin with "Public", "Priv", or "CEII", as applicable, to clearly indicate the security designation of the file. Both versions of the Form 556 should be unaltered PDF copies of the Form 556, as available for download from www.ferc.gov/QF. To redact data from the public copy of the submittal, simply omit the relevant data from the Form. For numerical fields, leave the redacted fields blank. For text fields, complete as much of the field as possible, and replace the redacted portions of the field with the word "REDACTED" in brackets. Be sure to identify above all fields which contain data for which you are seeking non-public status.

The Commission is not responsible for detecting or correcting filer errors, including those errors related to security designation. If your documents contain sensitive information, make sure they are filed using the proper security designation.

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, DC

OMB Control # 1902-0075
Expiration 01/31/2027

Form 556 Certification of Qualifying Facility (QF) Status for a Small Power Production or Cogeneration Facility

Application Information

1a Full name of applicant (legal entity on whose behalf qualifying facility status is sought for this facility)

1b Applicant street address

1c City

1d State/province

1e Postal code

1f Country (if not United States)

1g Telephone number

1h Has the instant facility ever previously been certified as a QF? Yes ☐ No ☐

1i If yes, provide the docket number of the last known QF filing pertaining to this facility: QF ____ - ______ - ____

1j Under which certification process is the applicant making this filing?

☐ Notice of self-certification (see note below)

☐ Application for Commission certification (requires filing fee; see "Filing Fee" section on page 2)

Note: a notice of self-certification is a notice by the applicant itself that its facility complies with the requirements for QF status. A notice of self-certification does not establish a proceeding, and the Commission does not review a notice of self-certification to verify compliance. See the "What to Expect From the Commission After You File" section on page 4 for more information.

1k What type(s) of QF status is the applicant seeking for its facility? (check all that apply)

☐ Qualifying small power production facility status ☐ Qualifying cogeneration facility status

1l What is the purpose and expected effective date(s) of this filing?

☐ Original certification; facility expected to be installed by __________ and to begin operation on __________

☐ Change(s) to a previously certified facility to be effective on __________
(identify type(s) of change(s) below, and describe change(s) in the Miscellaneous section starting on page 24)

- ☐ Name change and/or other administrative change(s)
- ☐ Change in ownership
- ☐ Change(s) affecting plant equipment, fuel use, power production capacity and/or cogeneration thermal output

☐ Supplement or correction to a previous filing submitted on __________
(describe the supplement or correction in the Miscellaneous section starting on page 24)

1m If any of the following three statements is true, check the box(es) that describe your situation and complete the form to the extent possible, explaining any special circumstances in the Miscellaneous section starting on page 24.

☐ The instant facility complies with the Commission's QF requirements by virtue of a waiver of certain regulations previously granted by the Commission in an order dated __________ (specify any other relevant waiver orders in the Miscellaneous section starting on page 24)

☐ The instant facility would comply with the Commission's QF requirements if a petition for waiver submitted concurrently with this application is granted

☐ The instant facility complies with the Commission's regulations, but has special circumstances, such as the employment of unique or innovative technologies not contemplated by the structure of this form, that make the demonstration of compliance via this form difficult or impossible (describe in Misc. section starting on p. 24)

Contact Information

2a Name of contact person

2b Telephone number

2c Which of the following describes the contact person's relationship to the applicant? (check one)

- ☐ Applicant (self)
- ☐ Employee, owner or partner of applicant authorized to represent the applicant
- ☐ Employee of a company affiliated with the applicant authorized to represent the applicant on this matter
- ☐ Lawyer, consultant, or other representative authorized to represent the applicant on this matter

2d Company or organization name (if applicant is an individual, check here and skip to line 2e) ☐

2e Street address (if same as Applicant, check here and skip to line 3a) ☐

2f City

2g State/province

2h Postal code

2i Country (if not United States)

Facility Identification and Location

3a Facility name

3b Street address (if a street address does not exist for the facility, check here and skip to line 3c) ☐

3c Geographic coordinates: Specify the latitude and longitude coordinates of the facility in degrees (to three decimal places). Use the following formula to convert to decimal degrees from degrees, minutes and seconds: decimal degrees = degrees + (minutes/60) + (seconds/3600). See the "Geographic Coordinates" section on page 5 for help.

Latitude ____________ degrees Choose +/-   Longitude ____________ degrees Choose +/-

3d City (if unincorporated, check here and enter nearest city) ☐

3e State/province

3f County (or check here for independent city) ☐

3g Country (if not United States)

Transacting Utilities

Identify the electric utilities that are contemplated to transact with the facility.

4a Identify utility interconnecting with the facility

4b Identify utilities providing wheeling service or check here if none ☐

4c Identify utilities purchasing the useful electric power output or check here if none ☐

4d Identify utilities providing supplementary power, backup power, maintenance power, and/or interruptible power service or check here if none ☐

Ownership and Operation

5a Direct ownership as of effective date or operation date: Identify all direct owners of the facility holding at least 10 percent equity interest. For each identified owner, also (1) indicate whether that owner is an electric utility, as defined in section 3(22) of the Federal Power Act (16 U.S.C. 796(22)), or a holding company, as defined in section 1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(8)), and (2) for owners which are electric utilities or holding companies, provide the percentage of equity interest in the facility held by that owner. If no direct owners hold at least 10 percent equity interest in the facility, then provide the required information for the two direct owners with the largest equity interest in the facility.

	Full legal names of direct owners	Electric utility or holding company	If Yes, % equity interest
1)		Yes ☐ No ☐	%
2)		Yes ☐ No ☐	%
3)		Yes ☐ No ☐	%
4)		Yes ☐ No ☐	%
5)		Yes ☐ No ☐	%
6)		Yes ☐ No ☐	%
7)		Yes ☐ No ☐	%
8)		Yes ☐ No ☐	%
9)		Yes ☐ No ☐	%
10)		Yes ☐ No ☐	%

☐ Check here and continue in the Miscellaneous section starting on page 24 if additional space is needed

5b Upstream (i.e., indirect) ownership as of effective date or operation date: Identify all upstream (i.e., indirect) owners of the facility that both (1) hold at least 10 percent equity interest in the facility, and (2) are electric utilities, as defined in section 3(22) of the Federal Power Act (16 U.S.C. 796(22)), or holding companies, as defined in section 1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(8)). Also provide the percentage of equity interest in the facility held by such owners. (Note that, because upstream owners may be subsidiaries of one another, total percent equity interest reported may exceed 100 percent.)

Check here if no such upstream owners exist. ☐

	Full legal names of electric utility or holding company upstream owners	% equity interest
1)		%
2)		%
3)		%
4)		%
5)		%
6)		%
7)		%
8)		%
9)		%
10)		%

☐ Check here and continue in the Miscellaneous section starting on page 24 if additional space is needed

5c Identify the facility operator

Energy Input

6a Describe the primary energy input: (check one main category and, if applicable, one subcategory)

☐ Biomass (specify)
- ☐ Landfill gas
- ☐ Manure digester gas
- ☐ Municipal solid waste
- ☐ Sewage digester gas
- ☐ Wood
- ☐ Other biomass (describe on page 24)

☐ Waste (specify type below in line 6b)

☐ Renewable resources (specify)
- ☐ Hydro power - river
- ☐ Hydro power - tidal
- ☐ Hydro power - wave
- ☐ Solar - photovoltaic
- ☐ Solar - thermal
- ☐ Wind
- ☐ Other renewable resource (describe on page 24)

☐ Geothermal

☐ Fossil fuel (specify)
- ☐ Coal (not waste)
- ☐ Fuel oil/diesel
- ☐ Natural gas (not waste)
- ☐ Other fossil fuel (describe on page 24)

☐ Other (describe on page 24)

6b If you specified "waste" as the primary energy input in line 6a, indicate the type of waste fuel used: (check one)

☐ Waste fuel listed in 18 C.F.R. § 292.202(b) (specify one of the following)
- ☐ Anthracite culm produced prior to July 23, 1985
- ☐ Anthracite refuse that has an average heat content of 6,000 Btu or less per pound and has an average ash content of 45 percent or more
- ☐ Bituminous coal refuse that has an average heat content of 9,500 Btu per pound or less and has an average ash content of 25 percent or more
- ☐ Top or bottom subbituminous coal produced on Federal lands or on Indian lands that has been determined to be waste by the United States Department of the Interior's Bureau of Land Management (BLM) or that is located on non-Federal or non-Indian lands outside of BLM's jurisdiction, provided that the applicant shows that the latter coal is an extension of that determined by BLM to be waste
- ☐ Coal refuse produced on Federal lands or on Indian lands that has been determined to be waste by the BLM or that is located on non- Federal or non-Indian lands outside of BLM's jurisdiction, provided that applicant shows that the latter is an extension of that determined by BLM to be waste
- ☐ Lignite produced in association with the production of montan wax and lignite that becomes exposed as a result of such a mining operation
- ☐ Gaseous fuels (except natural gas and synthetic gas from coal) (describe on page 24)
- ☐ Waste natural gas from gas or oil wells (describe on page 24 how the gas meets the requirements of 18 C.F.R. § 2.400 for waste natural gas; include with your filing any materials necessary to demonstrate compliance with 18 C.F.R. § 2.400)
- ☐ Materials that a government agency has certified for disposal by combustion (describe on page 24)
- ☐ Heat from exothermic reactions (describe on page 24)
- ☐ Residual heat (describe on page 24)
- ☐ Used rubber tires
- ☐ Plastic materials
- ☐ Refinery off-gas
- ☐ Petroleum coke

☐ Other waste energy input that has little or no commercial value and exists in the absence of the qualifying facility industry (describe in the Miscellaneous section starting on page 24; include a discussion of the fuel's lack of commercial value and existence in the absence of the qualifying facility industry)

6c Provide the average energy input, calculated on a calendar year basis, in terms of Btu/h for the following fossil fuel energy inputs, and provide the related percentage of the total average annual energy input to the facility (18 C.F.R. § 292.202(j)). For any oil or natural gas fuel, use lower heating value (18 C.F.R. § 292.202(m)).

Fuel	Annual average energy input for specified fuel	Percentage of total annual energy input
Natural gas	Btu/h	%
Oil-based fuels	Btu/h	%
Coal	Btu/h	%

Technical Facility Information

Indicate the maximum gross and maximum net electric power production capacity of the facility at the point(s) of delivery by completing the worksheet below. Respond to all items. If any of the parasitic loads and/or losses identified in lines 7b through 7e are negligible, enter zero for those lines.

7a The maximum gross power production capacity at the terminals of the individual generator(s) under the most favorable anticipated design conditions	kW
7b Parasitic station power used at the facility to run equipment which is necessary and integral to the power production process (boiler feed pumps, fans/blowers, office or maintenance buildings directly related to the operation of the power generating facility, etc.). If this facility includes non-power production processes (for instance, power consumed by a cogeneration facility's thermal host) , do not include any power consumed by the non-power production activities in your reported parasitic station power.	kW
7c Electrical losses in interconnection transformers	kW
7d Electrical losses in AC/DC conversion equipment, if any	kW
7e Other interconnection losses in power lines or facilities (other than transformers and AC/DC conversion equipment) between the terminals of the generator(s) and the point of interconnection with the utility	kW
7f Total deductions from gross power production capacity = 7b + 7c + 7d + 7e	0 kW
7g Maximum net power production capacity = 7a - 7f	0 kW

7h Description of facility and primary components: Describe the facility and its operation. Identify all boilers, heat recovery steam generators, prime movers (any mechanical equipment driving an electric generator), electrical generators, photovoltaic solar equipment, fuel cell equipment and/or other primary power generation equipment used in the facility. Descriptions of components should include (as applicable) specifications of the nominal capacities for mechanical output, electrical output, or steam generation of the identified equipment. For each piece of equipment identified, clearly indicate how many pieces of that type of equipment are included in the plant, and which components are normally operating or normally in standby mode. Provide a description of how the components operate as a system. Applicants for cogeneration facilities do not need to describe operations of systems that are clearly depicted on and easily understandable from a cogeneration facility's attached mass and heat balance diagram; however, such applicants should provide any necessary description needed to understand the sequential operation of the facility depicted in their mass and heat balance diagram. If additional space is needed, continue in the Miscellaneous section starting on page 24.

Information Required for Small Power Production Facility

If you indicated in line 1k that you are seeking qualifying small power production facility status for your facility, then you must respond to the items on this page. Otherwise, skip pages 11 through 15.

Certification of Compliance with Size Limitations

Pursuant to 18 C.F.R. § 292.204(a), the power production capacity of any small power production facility, 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. To demonstrate compliance with this size limitation, or to demonstrate that your facility is exempt from this size limitation under the Solar, Wind, Waste, and Geothermal Power Production Incentives Act of 1990 (Pub. L. 101-575, 104 Stat. 2834 (1990) *as amended by* Pub. L. 102-46, 105 Stat. 249 (1991)), respond to lines 8a through 8f below (as applicable).

Electric Generating Equipment

Electrical generating equipment will refer to all boilers, heat recovery steam generators, prime movers (any mechanical equipment driving an electric generator), electrical generators, photovoltaic solar panels, inverters, fuel cell equipment and/or other primary power generation equipment used in the facility, excluding equipment for gathering energy to be used in the facility. Each wind turbine on a wind farm and each solar panel in a solar facility is considered electrical generating equipment because each wind turbine and each solar panel is independently capable of producing electric energy.

Distance

The distance between two facilities is to be measured from the edge of the closest electrical generating equipment for which qualification or recertification is sought to the edge of the nearest electrical generating equipment of the other affiliated small power production qualifying facility using the same energy resource. An affiliated small power production QF located one mile or less from the instant facility is irrebuttably presumed to be at the same site. An affiliated small power production QF located more than one mile and less than 10 miles from the instant facility is rebuttably presumed to be at a separate site. An affiliated small power production QF located 10 miles or more from the instant facility is irrebuttably presumed to be located at a separate site.

8a Identify affiliated small power production QFs located less than 10 miles from the electrical generating equipment of the instant facility that use the same energy resource and are held (with at least a 5 percent equity interest) by any of the entities identified in lines 5a or 5b or their affiliates. Specify the latitude and longitude coordinates for both the applicant and the affiliate small power production QF based on the nearest electrical generating equipment for each facility. Report coordinates in degrees (to three decimal places) as a positive number for east and north or a negative number for west and south. Use the following formula to convert to decimal degrees from degrees, minutes and seconds: decimal degrees = degrees + (minutes/60) + (seconds/3600). See the "Geographic Coordinates" section on page 5 for help obtaining coordinates. The distances for each facility listed below will be automatically calculated from the reported coordinates. See **www.ferc.gov/QF** for more information on how this form calculates distance.

Check here if no such facilities exist. ☐

1)

Facility location (city or county, state)	Root docket # (if any)	Maximum net power production capacity	Common owner(s)
	QF ____ - ____	kW	

Coordinates (in degrees) and Distance (miles):

Closest electrical generating equipment for applicant's facility:

Latitude ______ Choose +/- Longitude ______ Choose +/-

Closest electrical generating equipment for affiliate's facility:

Latitude ______ Choose +/- Longitude ______ Choose +/-

Distance

0 miles

Certification of Compliance with Size Limitations (continued)

8a Continued

2)

Facility location (city or county, state)	Root docket # (if any)	Maximum net power production capacity	Common owner(s)
	QF -	kW	

Coordinates (in degrees) and Distance (miles):

Closest electrical generating equipment for applicant's facility:

Latitude Choose +/- Longitude Choose +/-

Closest electrical generating equipment for affiliate's facility:

Latitude Choose +/- Longitude Choose +/-

Distance: 0 miles

3)

Facility location (city or county, state)	Root docket # (if any)	Maximum net power production capacity	Common owner(s)
	QF -	kW	

Coordinates (in degrees) and Distance (miles):

Closest electrical generating equipment for applicant's facility:

Latitude Choose +/- Longitude Choose +/-

Closest electrical generating equipment for affiliate's facility:

Latitude Choose +/- Longitude Choose +/-

Distance: 0 miles

4)

Facility location (city or county, state)	Root docket # (if any)	Maximum net power production capacity	Common owner(s)
	QF -	kW	

Coordinates (in degrees) and Distance (miles):

Closest electrical generating equipment for applicant's facility:

Latitude Choose +/- Longitude Choose +/-

Closest electrical generating equipment for affiliate's facility:

Latitude Choose +/- Longitude Choose +/-

Distance: 0 miles

5)

Facility location (city or county, state)	Root docket # (if any)	Maximum net power production capacity	Common owner(s)
	QF -	kW	

Coordinates (in degrees) and Distance (miles):

Closest electrical generating equipment for applicant's facility:

Latitude Choose +/- Longitude Choose +/-

Closest electrical generating equipment for affiliate's facility:

Latitude Choose +/- Longitude Choose +/-

Distance: 0 miles

Certification of Compliance with Size Limitations (continued)

8a Continued

6)

Facility location (city or county, state)	Root docket # (if any)	Maximum net power production capacity	Common owner(s)
	QF -	kW	

Coordinates (in degrees) and Distance (miles):

Closest electrical generating equipment for applicant's facility:

Latitude Choose +/- Longitude Choose +/-

Closest electrical generating equipment for affiliate's facility:

Latitude Choose +/- Longitude Choose +/-

Distance

0 miles

7)

Facility location (city or county, state)	Root docket # (if any)	Maximum net power production capacity	Common owner(s)
	QF -	kW	

Coordinates (in degrees) and Distance (miles):

Closest electrical generating equipment for applicant's facility:

Latitude Choose +/- Longitude Choose +/-

Closest electrical generating equipment for affiliate's facility:

Latitude Choose +/- Longitude Choose +/-

Distance

0 miles

8)

Facility location (city or county, state)	Root docket # (if any)	Maximum net power production capacity	Common owner(s)
	QF -	kW	

Coordinates (in degrees) and Distance (miles):

Closest electrical generating equipment for applicant's facility:

Latitude Choose +/- Longitude Choose +/-

Closest electrical generating equipment for affiliate's facility:

Latitude Choose +/- Longitude Choose +/-

Distance

0 miles

9)

Facility location (city or county, state)	Root docket # (if any)	Maximum net power production capacity	Common owner(s)
	QF -	kW	

Coordinates (in degrees) and Distance (miles):

Closest electrical generating equipment for applicant's facility:

Latitude Choose +/- Longitude Choose +/-

Closest electrical generating equipment for affiliate's facility:

Latitude Choose +/- Longitude Choose +/-

Distance

0 miles

Certification of Compliance with Size Limitations (continued)

8a Continued

10)

Facility location (city or county, state)	Root docket # (if any)	Maximum net power production capacity	Common owner(s)
	QF -	kW	

Coordinates (in degrees) and Distance (miles):

Closest electrical generating equipment for applicant's facility:

Latitude Choose +/- Longitude Choose +/-

Closest electrical generating equipment for affiliate's facility:

Latitude Choose +/- Longitude Choose +/-

Distance

0 miles

☐ Check here and continue in the Miscellaneous section starting on page 24 if additional space is needed. Use the calculator below below to calculate distances based on facility coordinates.

Distance Calculator Specify the latitude and longitude coordinates for both the applicant and the affiliate small power production QF based on the nearest electrical generating equipment for each facility. Report coordinates in degrees (to three decimal places) as a positive number for east and north or a negative number for west and south. Use the following formula to convert to decimal degrees from degrees, minutes and seconds: decimal degrees = degrees + (minutes/60) + (seconds/3600). See the "Geographic Coordinates" section on page 5 for help obtaining coordinates. The distances for each facility listed below will be automatically calculated from the reported coordinates. See www.ferc.gov/QF for more information on how this form calculates distance.

Closest electrical generating equipment for applicant's facility (degrees):

Latitude Choose +/- Longitude Choose +/-

Closest electrical generating equipment for affiliate's facility (degrees):

Latitude Choose +/- Longitude Choose +/-

Distance

0 miles

8b You have the option below to assert preemptively that your facility is at a separate site from affiliated small power production QFs using the same energy resource more than one mile but less than 10 miles from your facility. If additional space is needed, continue in the Miscellaneous section starting on page 24.

Pursuant to 18 C.F.R. § 292.204(a)(2)(i)(C), if affiliated small power producer qualifying facilities are more than one mile but less than 10 miles apart there is a rebuttable presumption that they are at separate sites. The factors listed below are examples of the factors that the Commission may consider in deciding whether small power production facilities that are owned by the same person(s) or its affiliates are located “at the same site”: (1) *physical characteristics*, including such common characteristics as: infrastructure, property ownership, property leases, control facilities, access and easements, interconnection agreements, interconnection facilities up to the point of interconnection to the distribution or transmission system, collector systems or facilities, points of interconnection, motive force or fuel source, off-take arrangements, connections to the electrical grid, evidence of shared control systems, common permitting and land leasing, and shared step-up transformers; and (2) *ownership/other characteristics*, including such characteristics as whether the facilities in question are: owned or controlled by the same person(s) or affiliated persons(s), operated and maintained by the same or affiliated entity(ies), selling to the same electric utility, using common debt or equity financing, constructed by the same entity within 12 months, managing a power sales agreement executed within 12 months of a similar and affiliated small power production qualifying facility (continued next page)...

Certification of Compliance with Size Limitations (continued)

8b Continued

... (continued from previous page) in the same location, placed into service within 12 months of an affiliated small power production QF project's commercial operation date as specified in the power sales agreement, or sharing engineering or procurement contracts.

8c The Solar, Wind, Waste, and Geothermal Power Production Incentives Act of 1990 (Incentives Act) provides exemption from the size limitations in 18 C.F.R. § 292.204(a) for certain facilities that were certified prior to 1995. Are you seeking exemption from the size limitations in 18 C.F.R. § 292.204(a) by virtue of the Incentives Act?

☐ Yes (continue at line 8d below) ☐ No (skip lines 8d through 8f)

8d Was the original notice of self-certification or application for Commission certification of the facility filed on or before December 31, 1994? Yes ☐ No ☐

8e Did construction of the facility commence on or before December 31, 1999? Yes ☐ No ☐

8f If you answered No in line 8e, indicate whether reasonable diligence was exercised toward the completion of the facility, taking into account all factors relevant to construction? Yes ☐ No ☐

If you answered Yes, provide a brief narrative explanation in the Miscellaneous section starting on page 24 of the construction timeline (in particular, describe why construction started so long after the facility was certified) and the diligence exercised toward completion of the facility.

Certification of Compliance with Fuel Use Requirements

Pursuant to 18 C.F.R. § 292.204(b), qualifying small power production facilities may use fossil fuels, in minimal amounts, for only the following purposes: ignition; start-up; testing; flame stabilization; control use; alleviation or prevention of unanticipated equipment outages; and alleviation or prevention of emergencies, directly affecting the public health, safety, or welfare, which would result from electric power outages. The amount of fossil fuels used for these purposes may not exceed 25 percent of the total energy input of the facility during the 12-month period beginning with the date the facility first produces electric energy or any calendar year thereafter.

9a Certification of compliance with 18 C.F.R. § 292.204(b) with respect to uses of fossil fuel:

☐ Applicant certifies that the facility will use fossil fuels *exclusively* for the purposes listed above.

9b Certification of compliance with 18 C.F.R. § 292.204(b) with respect to amount of fossil fuel used annually:

☐ Applicant certifies that the amount of fossil fuel used at the facility will not, in aggregate, exceed 25 percent of the total energy input of the facility during the 12-month period beginning with the date the facility first produces electric energy or any calendar year thereafter.

Information Required for Cogeneration Facility

If you indicated in line 1k that you are seeking qualifying cogeneration facility status for your facility, then you must respond to the items on pages 16 through 18. Otherwise, skip pages 16 through 18.

General Cogeneration Information

Pursuant to 18 C.F.R. § 292.202(c), a cogeneration facility produces electric energy and forms of useful thermal energy (such as heat or steam) used for industrial, commercial, heating, or cooling purposes, through the sequential use of energy. Pursuant to 18 C.F.R. § 292.202(s), "sequential use" of energy means the following: (1) for a topping-cycle cogeneration facility, the use of reject heat from a power production process in sufficient amounts in a thermal application or process to conform to the requirements of the operating standard contained in 18 C.F.R. § 292.205(a); or (2) for a bottoming-cycle cogeneration facility, the use of at least some reject heat from a thermal application or process for power production.

10a What type(s) of cogeneration technology does the facility represent? (check all that apply)

☐ Topping-cycle cogeneration ☐ Bottoming-cycle cogeneration

10b To help demonstrate the sequential operation of the cogeneration process, and to support compliance with other requirements such as the operating and efficiency standards, include with your filing a mass and heat balance diagram depicting average annual operating conditions. This diagram must include certain items and meet certain requirements, as described below. You must check next to the description of each requirement below to certify that you have complied with these requirements.

Check to certify compliance with indicated requirement	Requirement
☐	Diagram must show orientation within system piping and/or ducts of all prime movers, heat recovery steam generators, boilers, electric generators, and condensers (as applicable), as well as any other primary equipment relevant to the cogeneration process.
☐	Any average annual values required to be reported in lines 10b, 12a, 13a, 13b, 13d, 13f, 14a, 15b, 15d and/or 15f must be computed over the anticipated hours of operation.
☐	Diagram must specify all fuel inputs by fuel type and average annual rate in Btu/h. Fuel for supplementary firing should be specified separately and clearly labeled. All specifications of fuel inputs should use lower heating values.
☐	Diagram must specify average gross electric output in kW or MW for each generator.
☐	Diagram must specify average mechanical output (that is, any mechanical energy taken off of the shaft of the prime movers for purposes not directly related to electric power generation) in horsepower, if any. Typically, a cogeneration facility has no mechanical output.
☐	At each point for which working fluid flow conditions are required to be specified (see below), such flow condition data must include mass flow rate (in lb/h or kg/s), temperature (in °F, R, °C or K), absolute pressure (in psia or kPa) and enthalpy (in Btu/lb or kJ/kg). Exception: For systems where the working fluid is *liquid only* (no vapor at any point in the cycle) and where the type of liquid and specific heat of that liquid are clearly indicated on the diagram or in the Miscellaneous section starting on page 24, only mass flow rate and temperature (not pressure and enthalpy) need be specified. For reference, specific heat at standard conditions for pure liquid water is approximately 1.002 Btu/(lb*R) or 4.195 kJ/(kg*K).
☐	Diagram must specify working fluid flow conditions at input to and output from each steam turbine or other expansion turbine or back-pressure turbine.
☐	Diagram must specify working fluid flow conditions at delivery to and return from each thermal application.
☐	Diagram must specify working fluid flow conditions at make-up water inputs.

EPAct 2005 Requirements for Fundamental Use of Energy Output from Cogeneration Facilities

EPAct 2005 cogeneration facilities: The Energy Policy Act of 2005 (EPAct 2005) established a new section 210(n) of the Public Utility Regulatory Policies Act of 1978 (PURPA), 16 USC 824a-3(n), with additional requirements for any qualifying cogeneration facility that (1) is seeking to sell electric energy pursuant to section 210 of PURPA and (2) was either not a cogeneration facility on August 8, 2005, or had not filed a self-certification or application for Commission certification of QF status on or before February 1, 2006. These requirements were implemented by the Commission in 18 C.F.R. § 292.205(d). Complete the lines below, carefully following the instructions, to demonstrate whether these additional requirements apply to your cogeneration facility and, if so, whether your facility complies with such requirements.

11a Was your facility operating as a qualifying cogeneration facility on or before August 8, 2005? Yes ☐ No ☐

11b Was the initial filing seeking certification of your facility (whether a notice of self-certification or an application for Commission certification) filed on or before February 1, 2006? Yes ☐ No ☐

If the answer to either line 11a or 11b is Yes, then continue at line 11c below. Otherwise, if the answers to both lines 11a and 11b are No, skip to line 11e below.

11c With respect to the design and operation of the facility, have any changes been implemented on or after February 2, 2006 that affect general plant operation, affect use of thermal output, and/or increase net power production capacity from the plant's capacity on February 1, 2006?

☐ Yes (continue at line 11d below)

☐ No. Your facility is not subject to the requirements of 18 C.F.R. § 292.205(d) at this time. However, it may be subject to to these requirements in the future if changes are made to the facility. At such time, the applicant would need to recertify the facility to determine eligibility. Skip lines 11d through 11j.

11d Does the applicant contend that the changes identified in line 11c are not so significant as to make the facility a "new" cogeneration facility that would be subject to the 18 C.F.R. § 292.205(d) cogeneration requirements?

☐ Yes. Provide in the Miscellaneous section starting on page 24 a description of any relevant changes made to the facility (including the purpose of the changes) and a discussion of why the facility should not be considered a "new" cogeneration facility in light of these changes. Skip lines 11e through 11j.

☐ No. Applicant stipulates to the fact that it is a "new" cogeneration facility (for purposes of determining the applicability of the requirements of 18 C.F.R. § 292.205(d)) by virtue of modifications to the facility that were initiated on or after February 2, 2006. Continue below at line 11e.

11e Will electric energy from the facility be sold pursuant to section 210 of PURPA?

☐ Yes. The facility is an EPAct 2005 cogeneration facility. You must demonstrate compliance with 18 C.F.R. § 292.205(d)(2) by continuing at line 11f below.

☐ No. Applicant certifies that energy will *not* be sold pursuant to section 210 of PURPA. Applicant also certifies its understanding that it must recertify its facility in order to determine compliance with the requirements of 18 C.F.R. § 292.205(d) *before* selling energy pursuant to section 210 of PURPA in the future. Skip lines 11f through 11j.

11f Is the net power production capacity of your cogeneration facility, as indicated in line 7g above, less than or equal to 5,000 kW?

☐ Yes, the net power production capacity is less than or equal to 5,000 kW. 18 C.F.R. § 292.205(d)(4) provides a rebuttable presumption that cogeneration facilities of 5,000 kW and smaller capacity comply with the requirements for fundamental use of the facility's energy output in 18 C.F.R. § 292.205(d)(2). Applicant certifies its understanding that, should the power production capacity of the facility increase above 5,000 kW, then the facility must be recertified to (among other things) demonstrate compliance with 18 C.F.R. § 292.205(d)(2). Skip lines 11g through 11j.

☐ No, the net power production capacity is greater than 5,000 kW. Demonstrate compliance with the requirements for fundamental use of the facility's energy output in 18 C.F.R. § 292.205(d)(2) by continuing on the next page at line 11g.

EPAct 2005 Requirements for Fundamental Use of Energy Output from Cogeneration Facilities (continued)

Lines 11g through 11k below guide the applicant through the process of demonstrating compliance with the requirements for "fundamental use" of the facility's energy output. 18 C.F.R. § 292.205(d)(2). Only respond to the lines on this page if the instructions on the previous page direct you to do so. Otherwise, skip this page.

18 C.F.R. § 292.205(d)(2) requires that the electrical, thermal, chemical and mechanical output of an EPAct 2005 cogeneration facility is used fundamentally for industrial, commercial, residential or institutional purposes and is not intended fundamentally for sale to an electric utility, taking into account technological, efficiency, economic, and variable thermal energy requirements, as well as state laws applicable to sales of electric energy from a qualifying facility to its host facility. If you were directed on the previous page to respond to the items on this page, then your facility is an EPAct 2005 cogeneration facility that is subject to this "fundamental use" requirement.

The Commission's regulations provide a two-pronged approach to demonstrating compliance with the requirements for fundamental use of the facility's energy output. First, the Commission has established in 18 C.F.R. § 292.205(d)(3) a "fundamental use test" that can be used to demonstrate compliance with 18 C.F.R. § 292.205(d)(2). Under the fundamental use test, a facility is considered to comply with 18 C.F.R. § 292.205(d)(2) if at least 50 percent of the facility's total annual energy output (including electrical, thermal, chemical and mechanical energy output) is used for industrial, commercial, residential or institutional purposes.

Second, an applicant for a facility that does not pass the fundamental use test may provide a narrative explanation of and support for its contention that the facility nonetheless meets the requirement that the electrical, thermal, chemical and mechanical output of an EPAct 2005 cogeneration facility is used fundamentally for industrial, commercial, residential or institutional purposes and is not intended fundamentally for sale to an electric utility, taking into account technological, efficiency, economic, and variable thermal energy requirements, as well as state laws applicable to sales of electric energy from a qualifying facility to its host facility.

Complete lines 11g through 11j below to determine compliance with the fundamental use test in 18 C.F.R. § 292.205(d)(3). Complete lines 11g through 11j *even if you do not intend to rely upon the fundamental use test to demonstrate compliance with 18 C.F.R. § 292.205(d)(2).*

11g Amount of electrical, thermal, chemical and mechanical energy output (net of internal generation plant losses and parasitic loads) expected to be used annually for industrial, commercial, residential or institutional purposes and not sold to an electric utility	MWh
11h Total amount of electrical, thermal, chemical and mechanical energy expected to be sold to an electric utility	MWh
11i Percentage of total annual energy output expected to be used for industrial, commercial, residential or institutional purposes and not sold to a utility = 100 * 11g /(11g + 11h)	0 %

11j Is the response in line 11i greater than or equal to 50 percent?

☐ Yes. Your facility complies with 18 C.F.R. § 292.205(d)(2) by virtue of passing the fundamental use test provided in 18 C.F.R. § 292.205(d)(3). Applicant certifies its understanding that, if it is to rely upon passing the fundamental use test as a basis for complying with 18 C.F.R. § 292.205(d)(2), then the facility must comply with the fundamental use test both in the 12-month period beginning with the date the facility first produces electric energy, and in all subsequent calendar years.

☐ No. Your facility does not pass the fundamental use test. Instead, you must provide in the Miscellaneous section starting on page 24 a narrative explanation of and support for why your facility meets the requirement that the electrical, thermal, chemical and mechanical output of an EPAct 2005 cogeneration facility is used fundamentally for industrial, commercial, residential or institutional purposes and is not intended fundamentally for sale to an electric utility, taking into account technological, efficiency, economic, and variable thermal energy requirements, as well as state laws applicable to sales of electric energy from a QF to its host facility. Applicants providing a narrative explanation of why their facility should be found to comply with 18 C.F.R. § 292.205(d)(2) in spite of non-compliance with the fundamental use test may want to review paragraphs 47 through 61 of Order No. 671 (accessible from the Commission's QF website at www.ferc.gov/QF), which provide discussion of the facts and circumstances that may support their explanation. Applicant should also note that the percentage reported above will establish the standard that that facility must comply with, both for the 12-month period beginning with the date the facility first produces electric energy, and in all subsequent calendar years. *See* Order No. 671 at paragraph 51. As such, the applicant should make sure that it reports appropriate values on lines 11g and 11h above to serve as the relevant annual standard, taking into account expected variations in production conditions.

Information Required for Topping-Cycle Cogeneration Facility

If you indicated in line 10a that your facility represents topping-cycle cogeneration technology, then you must respond to the items on pages 19 and 20. Otherwise, skip pages 19 and 20.

Usefulness of Topping-Cycle Thermal Output

The thermal energy output of a topping-cycle cogeneration facility is the net energy made available to an industrial or commercial process or used in a heating or cooling application. Pursuant to sections 292.202(c), (d) and (h) of the Commission's regulations (18 C.F.R. §§ 292.202(c), (d) and (h)), the thermal energy output of a qualifying topping-cycle cogeneration facility must be useful. In connection with this requirement, describe the thermal output of the topping-cycle cogeneration facility by responding to lines 12a and 12b below.

12a Identify and describe each thermal host, and specify the annual average rate of thermal output made available to each host for each use. For hosts with multiple uses of thermal output, provide the data for each use *in separate rows*.

	Name of entity (thermal host) taking thermal output	Thermal host's relationship to facility; Thermal host's use of thermal output	Average annual rate of thermal output attributable to use (net of heat contained in process return or make-up water)
1)		Select thermal host's relationship to facility Select thermal host's use of thermal output	Btu/h
2)		Select thermal host's relationship to facility Select thermal host's use of thermal output	Btu/h
3)		Select thermal host's relationship to facility Select thermal host's use of thermal output	Btu/h
4)		Select thermal host's relationship to facility Select thermal host's use of thermal output	Btu/h
5)		Select thermal host's relationship to facility Select thermal host's use of thermal output	Btu/h
6)		Select thermal host's relationship to facility Select thermal host's use of thermal output	Btu/h

☐ Check here and continue in the Miscellaneous section starting on page 24 if additional space is needed

12b Demonstration of usefulness of thermal output: At a minimum, provide a brief description of each use of the thermal output identified above. In some cases, this brief description is sufficient to demonstrate usefulness. However, if your facility's use of thermal output is not common, and/or if the usefulness of such thermal output is not reasonably clear, then you must provide additional details as necessary to demonstrate usefulness. Your application may be rejected and/or additional information may be required if an insufficient showing of usefulness is made. (Exception: If you have previously received a Commission certification approving a specific use of thermal output related to the instant facility, then you need only provide a brief description of that use and a reference by date and docket number to the order certifying your facility with the indicated use. Such exemption may not be used if any change creates a material deviation from the previously authorized use.) If additional space is needed, continue in the Miscellaneous section starting on page 24.

Topping-Cycle Operating and Efficiency Value Calculation

Applicants for facilities representing topping-cycle technology must demonstrate compliance with the topping-cycle operating standard and, if applicable, efficiency standard. Section 292.205(a)(1) of the Commission's regulations (18 C.F.R. § 292.205(a)(1)) establishes the operating standard for topping-cycle cogeneration facilities: the useful thermal energy output must be no less than 5 percent of the total energy output. Section 292.205(a)(2) (18 C.F.R. § 292.205(a)(2)) establishes the efficiency standard for topping-cycle cogeneration facilities for which installation commenced on or after March 13, 1980: the useful power output of the facility plus one-half the useful thermal energy output must (A) be no less than 42.5 percent of the total energy input of natural gas and oil to the facility; and (B) if the useful thermal energy output is less than 15 percent of the total energy output of the facility, be no less than 45 percent of the total energy input of natural gas and oil to the facility. To demonstrate compliance with the topping-cycle operating and/or efficiency standards, or to demonstrate that your facility is exempt from the efficiency standard based on the date that installation commenced, respond to lines 13a through 13l below.

If you indicated in line 10a that your facility represents *both* topping-cycle and bottoming-cycle cogeneration technology, then respond to lines 13a through 13l below considering only the energy inputs and outputs attributable to the topping-cycle portion of your facility. Your mass and heat balance diagram must make clear which mass and energy flow values and system components are for which portion (topping or bottoming) of the cogeneration system.

13a Indicate the annual average rate of useful thermal energy output made available to the host(s), net of any heat contained in condensate return or make-up water	Btu/h
13b Indicate the annual average rate of net electrical energy output	kW
13c Multiply line 13b by 3,412 to convert from kW to Btu/h	0 Btu/h
13d Indicate the annual average rate of mechanical energy output taken directly off of the shaft of a prime mover for purposes not directly related to power production (this value is usually zero)	hp
13e Multiply line 13d by 2,544 to convert from hp to Btu/h	0 Btu/h
13f Indicate the annual average rate of energy input from natural gas and oil	Btu/h
13g Topping-cycle operating value = 100 * 13a / (13a + 13c + 13e)	0 %
13h Topping-cycle efficiency value = 100 * (0.5*13a + 13c + 13e) / 13f	0 %

13i Compliance with operating standard: Is the operating value shown in line 13g greater than or equal to 5%?

☐ Yes (complies with operating standard) ☐ No (does not comply with operating standard)

13j Did installation of the facility in its current form commence on or after March 13, 1980?

☐ Yes. Your facility is subject to the efficiency requirements of 18 C.F.R. § 292.205(a)(2). Demonstrate compliance with the efficiency requirement by responding to line 13k or 13l, as applicable, below.

☐ No. Your facility is exempt from the efficiency standard. Skip lines 13k and 13l.

13k Compliance with efficiency standard (for low operating value): If the operating value shown in line 13g is less than 15%, then indicate below whether the efficiency value shown in line 13h greater than or equal to 45%:

☐ Yes (complies with efficiency standard) ☐ No (does not comply with efficiency standard)

13l Compliance with efficiency standard (for high operating value): If the operating value shown in line 13g is greater than or equal to 15%, then indicate below whether the efficiency value shown in line 13h is greater than or equal to 42.5%:

☐ Yes (complies with efficiency standard) ☐ No (does not comply with efficiency standard)

Information Required for Bottoming-Cycle Cogeneration Facility

If you indicated in line 10a that your facility represents bottoming-cycle cogeneration technology, then you must respond to the items on pages 21 and 22. Otherwise, skip pages 21 and 22.

Usefulness of Bottoming-Cycle Thermal Output

The thermal energy output of a bottoming-cycle cogeneration facility is the energy related to the process(es) from which at least some of the reject heat is then used for power production. Pursuant to sections 292.202(c) and (e) of the Commission's regulations (18 C.F.R. § 292.202(c) and (e)) , the thermal energy output of a qualifying bottoming-cycle cogeneration facility must be useful. In connection with this requirement, describe the process(es) from which at least some of the reject heat is used for power production by responding to lines 14a and 14b below.

14a Identify and describe each thermal host and each bottoming-cycle cogeneration process engaged in by each host. For hosts with multiple bottoming-cycle cogeneration processes, provide the data for each process *in separate rows*.

	Name of entity (thermal host) performing the process from which at least some of the reject heat is used for power production	Thermal host's relationship to facility; Thermal host's process type	Has the energy input to the thermal host been augmented for purposes of increasing power production capacity? (if Yes, describe on p. 24)
1)		Select thermal host's relationship to facility Select thermal host's process type	Yes ☐ No ☐
2)		Select thermal host's relationship to facility Select thermal host's process type	Yes ☐ No ☐
3)		Select thermal host's relationship to facility Select thermal host's process type	Yes ☐ No ☐

☐ Check here and continue in the Miscellaneous section starting on page 24 if additional space is needed

14b Demonstration of usefulness of thermal output: At a minimum, provide a brief description of each process identified above. In some cases, this brief description is sufficient to demonstrate usefulness. However, if your facility's process is not common, and/or if the usefulness of such thermal output is not reasonably clear, then you must provide additional details as necessary to demonstrate usefulness. Your application may be rejected and/or additional information may be required if an insufficient showing of usefulness is made. (Exception: If you have previously received a Commission certification approving a specific bottoming-cycle process related to the instant facility, then you need only provide a brief description of that process and a reference by date and docket number to the order certifying your facility with the indicated process. Such exemption may not be used if any material changes to the process have been made.) If additional space is needed, continue in the Miscellaneous section starting on page 24.

Bottoming-Cycle Operating and Efficiency Value Calculation

Applicants for facilities representing bottoming-cycle technology and for which installation commenced on or after March 13, 1990 must demonstrate compliance with the bottoming-cycle efficiency standards. Section 292.205(b) of the Commission's regulations (18 C.F.R. § 292.205(b)) establishes the efficiency standard for bottoming-cycle cogeneration facilities: the useful power output of the facility must be no less than 45 percent of the energy input of natural gas and oil for supplementary firing. To demonstrate compliance with the bottoming-cycle efficiency standard (if applicable), or to demonstrate that your facility is exempt from this standard based on the date that installation of the facility began, respond to lines 15a through 15h below.

If you indicated in line 10a that your facility represents *both* topping-cycle and bottoming-cycle cogeneration technology, then respond to lines 15a through 15h below considering only the energy inputs and outputs attributable to the bottoming-cycle portion of your facility. Your mass and heat balance diagram must make clear which mass and energy flow values and system components are for which portion of the cogeneration system (topping or bottoming).

15a Did installation of the facility in its current form commence on or after March 13, 1980?

☐ Yes. Your facility is subject to the efficiency requirement of 18 C.F.R. § 292.205(b). Demonstrate compliance with the efficiency requirement by responding to lines 15b through 15h below.

☐ No. Your facility is exempt from the efficiency standard. Skip the rest of page 22.

15b Indicate the annual average rate of net electrical energy output	kW
15c Multiply line 15b by 3,412 to convert from kW to Btu/h	0 Btu/h
15d Indicate the annual average rate of mechanical energy output taken directly off of the shaft of a prime mover for purposes not directly related to power production (this value is usually zero)	hp
15e Multiply line 15d by 2,544 to convert from hp to Btu/h	0 Btu/h
15f Indicate the annual average rate of supplementary energy input from natural gas or oil	Btu/h
15g Bottoming-cycle efficiency value = 100 * (15c + 15e) / 15f	0 %

15h Compliance with efficiency standard: Indicate below whether the efficiency value shown in line 15g is greater than or equal to 45%:

☐ Yes (complies with efficiency standard) ☐ No (does not comply with efficiency standard)

Certificate of Completeness, Accuracy and Authority

Applicant must certify compliance with and understanding of filing requirements by checking next to each item below and signing at the bottom of this section. Forms with incomplete Certificates of Completeness, Accuracy and Authority will be rejected by the Secretary of the Commission.

Signer identified below certifies the following: (check all items and applicable subitems)

- ☐ He or she has read the filing, including any information contained in any attached documents, such as cogeneration mass and heat balance diagrams, and any information contained in the Miscellaneous section starting on page 24, and knows its contents.
- ☐ He or she has provided all of the required information for certification, and the provided information is true as stated, to the best of his or her knowledge and belief.
- ☐ He or she possess full power and authority to sign the filing; as required by Rule 2005(a)(3) of the Commission's Rules of Practice and Procedure (18 C.F.R. § 385.2005(a)(3)), he or she is one of the following: (check one)
  - ☐ The person on whose behalf the filing is made
  - ☐ An officer of the corporation, trust, association, or other organized group on behalf of which the filing is made
  - ☐ An officer, agent, or employe of the governmental authority, agency, or instrumentality on behalf of which the filing is made
  - ☐ A representative qualified to practice before the Commission under Rule 2101 of the Commission's Rules of Practice and Procedure (18 C.F.R. § 385.2101) and who possesses authority to sign
- ☐ He or she has reviewed all automatic calculations and agrees with their results, unless otherwise noted in the Miscellaneous section starting on page 24.
- ☐ He or she has provided a copy of this Form 556 and all attachments to the utilities with which the facility will interconnect and transact (see lines 4a through 4d), as well as to the regulatory authorities of the states in which the facility and those utilities reside. See the Required Notice to Public Utilities and State Regulatory Authorities section on page 4 for more information.

Provide your signature, address and signature date below. Rule 2005(c) of the Commission's Rules of Practice and Procedure (18 C.F.R. § 385.2005(c)) provides that persons filing their documents electronically may use typed characters representing his or her name to sign the filed documents. A person filing this document electronically should sign (by typing his or her name) in the space provided below.

Your Signature	Your address	Date

Audit Notes

Commission Staff Use Only: ☐

Miscellaneous

Use this space to provide any information for which there was not sufficient space in the previous sections of the form to provide. For each such item of information *clearly identify the line number that the information belongs to*. You may also use this space to provide any additional information you believe is relevant to the certification of your facility.

Your response below is not limited to one page. Additional page(s) will automatically be inserted into this form if the length of your response exceeds the space on this page. Use as many pages as you require.

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.

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[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.

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

[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).

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.

<u>The Commission orders</u>:

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.

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).

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

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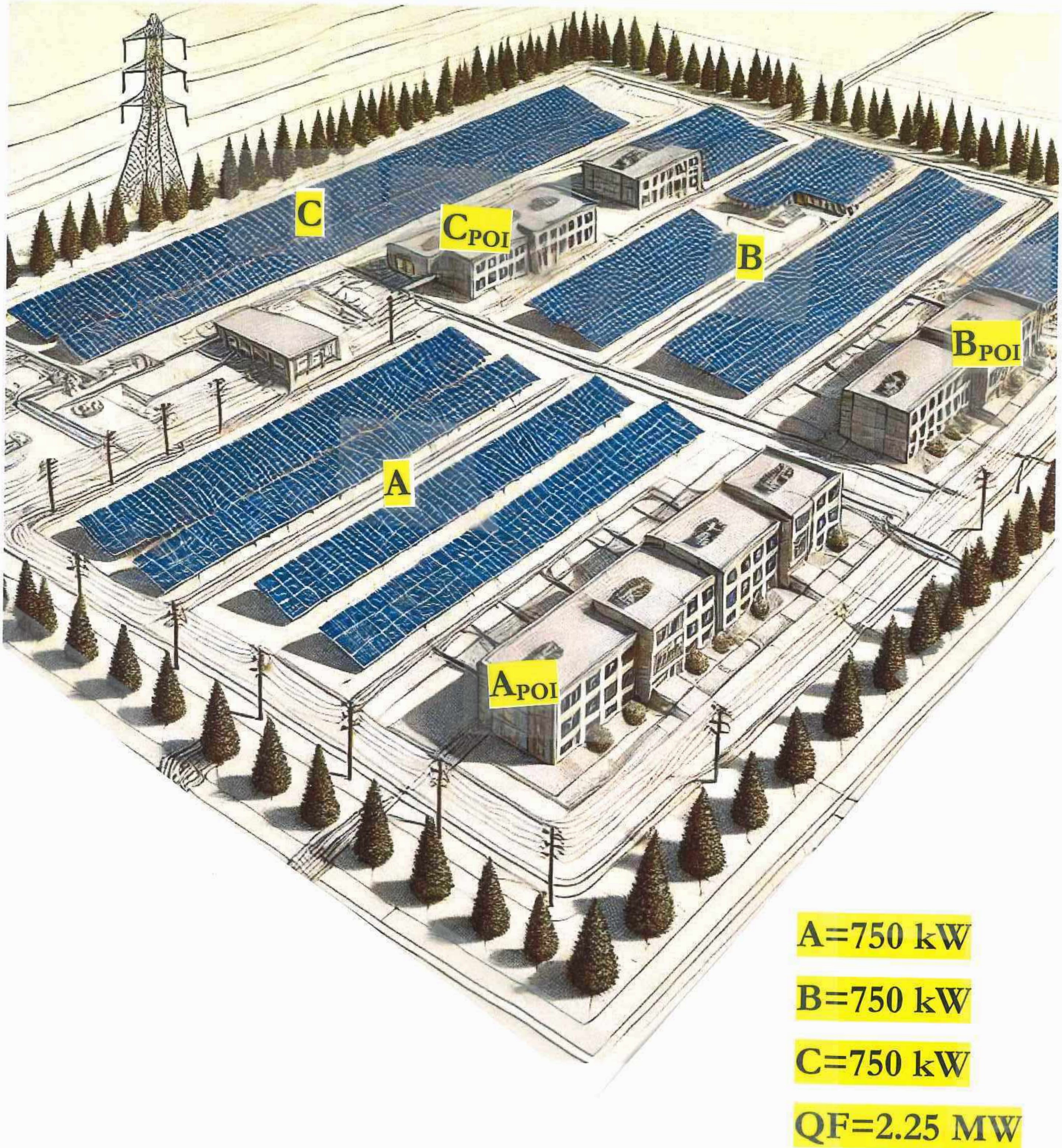
[2] *See* https://www.eia.gov/forecasts/capitalcost/pdf/updated_capcost.pdf at Table 1.

[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

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

s, 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.