STATE OF MINNESOTA
PUBLIC UTILITIES COMMISSION

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In the Matter of Updating the Generic Standards for the Interconnection and Operation of Distributed Generation Facilities Established under Minn. Stat. §216B.1611
Docket Nos. E999/CI-16-521 and E999/CI-01-1023

COMMENTS of the MINNESOTA SOLAR ENERGY INDUSTRIES ASSOCIATION (MnSEIA), VOTE SOLAR, FRESH ENERGY, and the ENVIRONMENTAL LAW AND POLICY CENTER (ELPC)

October 30, 2020

Docket No. CI-16-521/M-01-1023

Introduction

The Minnesota Solar Energy Industries Association (MnSEIA) is a 501(c)(6) nonprofit trade association that represents our state's solar businesses, with over 110 member companies, which employ over 4,000 Minnesotans.

ELPC is a 501(c)(3) nonprofit public interest organization that works to achieve cleaner air and cleaner water, promote renewable energy and energy efficiency resources, and preserve natural resources in Minnesota and the Midwest. ELPC has an office in Minneapolis and has members throughout the state of Minnesota and the Midwest.

Vote Solar (VS) is an independent 501(c)3 nonprofit working to repower the U.S. with clean energy by making solar power more accessible and affordable through effective policy advocacy. Vote Solar seeks to promote the development of solar at every scale, from distributed rooftop solar to large utility-scale plants. Vote Solar has over 90,000 members nationally, including over

2,500 members in Minnesota. Vote Solar is not a trade organization nor does it have corporate members.

Fresh Energy is a 501(c)3 nonprofit organization focused on shaping clean energy policy in Minnesota to ensure a just, prosperous, and resilient future powered by a carbon-neutral economy.

Our comments here today address the Minnesota Public Utilities Commission's (the "Commission" or PUC) August 28, 2020 Notice for Comment Period and provide further justification for modifying Attachment 6[1] of the Interconnection Standards with the suggested edits that we, along with other community stakeholders, filed in our March 27, 2018 Motion in this docket.

I. The Calculations of DG Tariff Rates for DG Projects Between 1 and 10 MW Submitted by the Rate-Regulated Utilities Are Neither Appropriate nor Reasonable

The utility calculations of DG Tariff Rates are not appropriate or reasonable for two reasons. First, avoided cost data is shielded from public viewing, so the appropriateness or reasonableness of that rate itself is unknown. Second, knowing what little we do, we think the way utilities implement § 216B.1611 is unreasonable.

A. Utility Practice of Labeling Avoided Cost Data "Trade Secret" Makes it Difficult to Opine on whether the Rates are "Appropriate and Reasonable."

As has been argued by Environmental Law & Policy Center and Institute for Local Self-Reliance in Docket No. PR-19-09, electric utilities in Minnesota withhold from the public avoided cost information and calculations pursuant to its annual PURPA filings required by Minn. R. 7835.0300 to 7835.1100.[2] Because Attachment 6 currently requires that the utilities base DG rates on these PURPA avoided costs, and because utilities forbid public access to the avoided cost information and calculations, it is difficult for us to opine on whether the rates are "appropriate and reasonable." There is a pending dispute before the Minnesota Court of Appeals that will provide future guidance on this practice.

Consistent with the position of Environmental Law & Policy Center and Institute for Local Self-Reliance, Joint Movants argue that Minn. R. 7835.1200 requires that the annual avoided

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[1] In the Matter of Updating the Generic Standards for the Interconnection and Operation of Distributed Generation Facilities Established under Minn. Stat. § 216B.1611, ORDER, Docket No. CI-16-521, (January 24, 2017) available at https://perma.cc/3JK7-YYT2, at *Hereinafter* "Attachment 6."

[2] COMMENTS OF THE ENVIRONMENTAL LAW AND POLICY CENTER AND INSTITUTE FOR LOCAL SELF RELIANCE, Docket No. 19-09, Doc. Id. 20191-149737-01, at 4-6 (Jan. 29, 2019).

cost filings be available for "public inspection." Only if the information is available to the public, can anyone meaningfully comment on whether the rates for purchase for DG projects is "appropriate and reasonable."

B. The Utility Implementation of 216B.1611 is Unreasonable

Joint Movants have argued that Attachment 6 of the 2004 Order needs revision in order to conform with the Legislative intent in Minn. Stat. § 216B.1611 to create a standard, statewide DG Tariff guidelines. However, even if the current Attachment 6 were to reflect the statutory language, utilities have misapplied Attachment 6. Currently, the only way for a developer to view pricing for the DG Tariff rates is to execute a non-disclosure agreement ("NDA") with the utility following proof of a legally enforceable obligation ("LEO"), such as site control and proof of financing.[3]

The utility requirement of the facility to have entered into LEOs before seeing a rate is unreasonable. Developers of DG facilities should expect to know with reasonable certainty what rate facility would be paid for energy, capacity, and other credits before entering into a LEO. To our knowledge, there is no other tariff in Minnesota that requires the developer of a generating facility to outlay resources in this manner before knowledge of what rates can be expected for that facility's energy and capacity.

We do acknowledge that an LEO may be an appropriate way for projects larger than 10MW to lock in pricing and illustrate that they are "real" projects. But this requirement is effectively included in the new MN DIP but is dubbed "deemed complete." For projects 10MW and under that are taking advantage of the new MN DIP, it makes practical sense that a project would need to be deemed complete prior to the utility locking in the facility's rate. However, it would be unduly onerous for a facility to need to be deemed complete before finding out whether the rate is worth developing a project, and it would be very onerous if the project had to qualify as an LEO and meet the requirements to be deemed complete. But this appears to be the way the utilities are implementing the DG Tariffs today.

We acknowledge that it is reasonable for a utility to want to avoid secure genuine trade secret data from public consumption. However, there must be a point in the application process where a developer can demonstrate its good faith to the utility that falls short of requiring that developer to invest time and resources into LEOs or being deemed complete. Reasonable tariff guidelines—and approved tariffs—should balance these interests.

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[3] *See* Otter Tail Power Answers to MnSEIA Information Requests 1-4.

Assuming the rates remain trade-secret and NDAs are required, we suggest that Attachment 6 include a basic test for developers to attain an NDA. All that should be required is 1) an attestation from the developer that they are DG developers that are considering a project; and 2) a statement of creditworthiness from an auditor. These parameters should meet the utilities' needs for confidentiality while not being overly burdensome on the prospective project.

II. <u>The Consistency of Attachment 6 with Existing Statutes and Rules</u>

In its June 17, 2019 Compliance Filing, Xcel Energy (Xcel) states that it intends to restrict the rates available to potential renewable Distributed Generation (DG) projects between 1 to 10 MW by limiting the rate for those renewable projects to Xcel's least cost renewable resource.[4] Effectively, Xcel is articulating that instead of providing a Distributed Generation Tariff Rate under Minn. Stat. §216B.1611, it would instead give the customer pricing from Minn. Stat. §216B.164.[5] Further, it would only give that customer a price set through the least cost bid for any renewable energy facility it had previously received pricing information from, because of its interpretation of the third sentence of the .164 statute.

A question to the impact of §216B.164, Subd. 4 and Minn. Rule 7835.4019 (a rule that gets its statutory authority from §216B.164, but not §216B.1611)[6] on the Attachment 6 revision process appeared in the Commission's Notice of Comment as well. So it is important that this utility created "red herring" be addressed and then set aside from further consideration.

We will illustrate that 1) Minn. Stat. §216B.1611 is not limited by Minn. Stat. §216B.164, Subd. 4, as they are separate statutes; 2) even if there were a tie between the two statutes, Minn. Stat. § 216B.164 is largely invalidated by PURPA; 3) if somehow Minn. Stat. §216B.164 can tie into Attachment 6 and is not overruled by PURPA, then the recent dispute between Red Lake Falls Community Hybrid, LLC and Otter Tail Power (PUC Docket 16-1021) illustrates the renewable energy provision should be read merely as guidance for administering an RFP process and that the Commission has the authority to set rates; and 4) if the Commission does not agree with us on the above, then this process of calculating true avoided costs for the Attachment 6 rates should be concluded anyway, because not all DG facilities are powered with renewable energy.

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[4] Northern States Power Company, d/b/a Xcel Energy, COMPLIANCE FILING, UPDATING GENERIC STANDARDS FOR UTILITY TARIFFS FOR INTERCONNECTION AND OPERATION OF DISTRIBUTED GENERATION FACILITIES ESTABLISHED UNDER MINN. STAT. §216B.1611, DOCKET NOS. E999/CI-16-521 & E999/CI-01-1023, Doc. Id 20196-153663-02 at 4 (Jun. 17, 2019).

[5] *Id.* (stating "If a developer asks us about using the rate table at tariff sheet 10-76, we inform the developer that the rate table would not apply to a renewable energy source because, as noted above, Minn. Stat. §216B.164, Subd. 4 controls how rates for renewable energy sources are set.").

[6] *See* Minn. Rule 7835.4019 at Statutory Authority (citing only "216A.05; 216B.08; 216B.164").

A. Minn. Stat. § 216B.1611 Is Not Limited By Minn. Stat. § 216B.164, Subd. 4

While there are legislative instructions on calculating avoided cost in Minn. Stat. § 216B.164, Subd. 4, as it pertains to Minnesota's implementation of the Public Utility Regulatory Policies Act ("PURPA"), such a limitation does not appear in the controlling statute at issue here, Minn. Stat. § 216B.1611. Nothing in Minn. Stat. § 216B.1611 references § 216B.164, so there is no legal support for limiting the DG Tariff by an unrelated statute. Further, there is no statutory requirement that Attachment 6 even use Avoided Cost pricing or other traditional methodologies for financing projects of similar size.

An analogous situation is the Value of Solar (VOS) methodology. The VOS, which is explicitly predicated on avoided cost methodologies, does not determine its avoided cost pricing on competitive solicitations despite creating pricing for renewable energy.[7] The methodology for VOS may mention "avoided costs," but it does not follow any statutory guidance for calculating avoided costs from Minn. Stat. § 216B.164, Subd. 4, even though the VOS itself is located in the same statute but six subdivisions lower (subd. 10). Once annual inputs are added, the VOS methodology feeds into a Tariff (the Value of Solar Tariff, or "VOST") to which customers can apply as a standard rate.[8]

In practice, Subd. 4 (b) is really only for projects looking specifically for financing under PURPA and that want traditionally calculated avoided costs as the rate for energy and capacity. These projects would likely be larger than 10 MW, and therefore do not qualify for the DG Tariff due to size. Because the Minnesota Investor Owned Utilities (IOUs) have FERC waivers, this would be the mechanism used to finance projects in the 10-20 MW range and that are interconnected to the transmission system. Attachment 6 is really about projects in the 10MW and under range and that are interconnected to the distribution system.[9]

Attachment 6 is similar to the VOS methodology in that it too is a methodology for determining a price that is located in a different but related tariff, namely, the "DG Tariff."[10] The only

[7] *See* ORDER APPROVING DISTRIBUTED SOLAR VALUE METHODOLOGY, In the Matter of Establishing a Distributed Solar Value Methodology under Minn. Stat. § 216B.164, subd. 10 (e) and (f), DOCKET NO. E-999/M-14-65, Doc. Id. 20144-97879-01 (Apr. 1, 2014).

[8] *See* Northern States Power Company, d/b/a Xcel Energy, 2021 VOS CALCULATION COMMUNITY SOLAR GARDENS PROGRAM, DOCKET NO. E002/M-13-867, Doc. Id. 20209-166369-01 (Sept. 1, 2020).

[9] *See* Minn. Stat. 216B.1611 Subd. 2 (a). ("The commission shall initiate a proceeding within 30 days of July 1, 2001, to establish, by order, generic standards for utility tariffs for the interconnection and parallel operation of distributed generation fueled by natural gas or a renewable fuel, or another similarly clean fuel or combination of fuels of no more than ten megawatts of interconnected capacity. […]")

[10] Minn. Stat. 216B.1611 Subd. 1 and 3.

material difference for the purposes of this discussion between Attachment 6 and the VOST is that Attachment 6 arises from an entirely different statute, § 216B.1611, which further differentiates the avoided cost methodologies in Attachment 6 from subd. 4 (b). The very similar situation between the VOS and the resulting VOST and Attachment 6 and the DG Tariff, illustrates Xcel's belief that Minn. Stat. § 216B164, Subd. 4 (b) must be applied elsewhere is a misapplication of law, and should be ignored.

However, not only is Xcel’s belief a misapplication of statute, it appears to be a misapplication of its own filed tariff. Section 10 of Xcel’s Ratebook includes its DG Tariff language. According to Section 10, current qualifications to access the DG Tariff rate are as follows:

> **QUALIFICATION**
> 1. Qualifying DG facilities may include but are not limited to, fuel cell, wind, solar, micro turbine generators and other utility industry accepted DG technologies, subject to Company’s approval.
> 2. Qualifying DG facilities may be those which do not qualify as “Qualifying Facilities” (QFs) under the Public Utility Regulatory Policy Act of 1978 (PURPA) or those which are QFs but where the customer elects not to exercise its rights to the pricing provided for under PURPA.
> 3. Qualifying DG facilities must be a permanently installed or similarly dedicated mobile generator serving the customer receiving retail electric service from the Company at the same site.[11]

When Xcel originally added the DG Tariff to its ratebook, it clearly understood that it was not required that a customer even be eligible to receive rates under PURPA, or Subd. 4b to receive the DG Tariff. They are very different tariffs. It is perplexing that its position now appears to be that the DG Tariff is somehow different for renewable projects than nonrenewable projects, despite its tariff specifically qualifying all technologies the same. Nothing in the rest of its current DG Tariff has any mention of different pricing for renewable energy, other than additional credits through Renewable Energy Certificates (RECs). The fact that Xcel is using Minn. Stat. § 216B.164 to depress pricing today when it was not applied back when renewables were more expensive is merely a way to avoid DG projects then and now, and it is a misapplication of the existing Attachment 6.

Furthermore, if Minn. Stat. § 216B.164 was to be applied to Minn. Stat. § 216B.1611 it would frustrate the statute’s encouragement of distributed generation. Minn. Stat. § 216B.1611 states

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[11] MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2, Section 10, Sheet 73, found at https://www.xcelenergy.com/staticfiles/xe-responsive/Company/Rates%20&%20Regulations/Rate%20Cases/Me_Section_10.pdf

that its purpose is in part to "promote the use of distributed resources in order to provide electric system benefits during periods of capacity constraints."[12] Part of what we are seeking through this Commission process is a revision of the current Attachment 6 methodology, which is currently not meeting the goals of the statute. We are seeking a revision to promote distributed generation. Taking an approach that would incorporate Minn. Stat. § 216B.164's avoided cost pricing would actually further frustrate the implementation of Attachment 6. It would take a currently unworkable process for DG deployment and make it worse. It would run contrary to the goals of the statute and undermine the very existence of the original Attachment 6.

B. Minn. Stat. § 216.164, Subd. 4, insofar as it constrains the avoided cost rate for renewable qualifying facilities only, is preempted by PURPA.

Section 210 of PURPA requires electric utilities to purchase energy and capacity from qualifying renewable and cogeneration facilities ("qualifying facilities" or "QFs"). The rates for such purchases are based on the utility's "avoided costs." Avoided costs are the incremental cost to the utility to either produce or procure energy or capacity itself (e.g., a representation of what is "avoided" by purchasing from a qualifying facility). PURPA's regulations prohibit discrimination in the setting of avoided cost rates. 18 C.F.R. § 292.304(a).

The United States Supreme Court has stated that "state law is preempted to the extent that it actually conflicts with federal law." *English v. Gen. Elec. Co*., 496 U.S. 72, 79 (1990). A conflict between federal and state law exists where state law "stands as an obstacle to the accomplishment and execution of the full purposes and objectives of Congress." *Hines v. Davidowitz*, 312 U.S. 52, 67 (1941); *see also Lankford v. Sherman*, 451 F.3d 496, 510 (8th Cir. 2006). Like federal statutes, federal regulations also preempt conflicting state law. *See Lankford*, 451 F.3d at 510; *see also Chapman v. Lab One*, 390 F.3d 620, 624 (8th Cir. 2004).

Minn. Stat. § 216.164, Subd. 4's "least cost renewable" limitation is in direct conflict with PURPA's regulations and the Federal Energy Regulatory Commission's interpretation of those regulations. Minn. Stat. § 216.164 is the Minnesota statute that implements the state's responsibilities under PURPA, and Minn. Stat. § 216.164, Subd. 4, requires avoided costs for renewable qualifying facilities be set at the purchasing utility's least cost renewable resource.

In *California Pub. Utilities Comm'n, et al*., FERC made clear that avoided costs must be based on all technologies (renewable or otherwise) able to sell to the utility:

[12] Minn. Stat. § 216B.1611, subd. 1(5).

> In *SoCal Edison*, the Commission stated that, regardless of how the state determines avoided cost, it must in its process reflect prices available from "all sources able to sell to the utility whose avoided cost is being determined." Thus, under *SoCal Edison*, if a state required a utility to purchase 10 percent of its energy needs from renewable resources, then a natural gas-fired unit, for example, would not be a source "able to sell" to that utility for the specified renewable resources segment of the utility's energy needs, and thus would not be relevant to determining avoided costs for that segment of the utility's energy needs. Stated more generally, *SoCal Edison* supports the proposition that, where a state requires a utility to procure a certain percentage of energy from generators with certain characteristics, generators with those characteristics constitute the sources that are relevant to the determination of the utility's avoided cost for that procurement requirement.

133 FERC 61,059, ¶ 27 (2010). The Ninth Circuit approvingly cited FERC's interpretation of PURPA in a case where the issue of technology-specific avoided costs arose. *Californians for Renewable Energy v. California Pub. Utilities Comm'n*, 922 F.3d 929, 937 (9th Cir. 2019) ("[W]here a state has an RPS [renewable portfolio standard] and the utility is using a QF's energy to meet the RPS, the utility cannot calculate avoided costs based on energy sources that would not also meet the RPS.").

Minn. Stat. § 216.164, Subd. 4's "least cost renewable" limitation stands in direct conflict with FERC's interpretation of PURPA. Because more than just renewable generators are "able to sell" to electric utilities in Minnesota, a requirement that limits renewable QFs to a utility's lowest cost renewable resource directly conflicts with FERC's decision in *California Pub. Utilities Comm'n, et al*. As a result, Minn. Stat. § 216B.164, Subd. 4's least cost renewable limitation "stands as an obstacle to the accomplishment and execution of the full purposes and objectives of Congress." *Hines*, 312 U.S. at 67.

Minn. Stat. § 216.164, Subd. 4 also conflicts with the anti-discrimination provision contained in 18 C.F.R. § 292.304(a). While 18 C.F.R. § 292.304(c)(3) states that standard avoided cost rates "[m]ay differentiate among qualifying facilities using various technologies on the basis of the supply characteristics of the different technologies," Minn. Stat. § 216.164, Subd. 4, does not base its discrimination based on supply characteristics of different renewable technologies. Instead, it creates a blanket, unavoidable requirement that avoided cost rates for renewable QFs be set at a utility's least cost renewable energy facility regardless of whether that least cost renewable energy facility actually represents the utility's avoided costs.

C. The Decision in *Red Lake Falls* Demonstrates the Availability of Rates Other than the Lowest Renewable Energy Bid

The outcome of the most recent PURPA decision, Minnesota PUC Docket E-017/CG-16-1021, decisively illustrated that the least-cost renewable energy language is not applicable to projects in Minnesota.[13] In that docket Red Lake Falls, Community Hybrid LLC, a wind/solar hybrid project, was, among many things, seeking a determination of an avoided cost rate by the Commission after negotiations with Otter Tail Power failed to reach an agreed upon rate.[14]

The Commission initially sent the issue to a contested case proceeding for an Administrative Law Judge (ALJ) recommendation. After hearing testimony from the Department of Commerce, Otter Tail Power and Red Lake Falls, Community Hybrid LLC, the ALJ decided that the statute should be interpreted in the strictest sense. He agreed with Otter Tail and the Department's recommendation.[15]

As the Commission summarized in its Order:

> The ALJ recommended that Otter Tail's full avoided costs for the Project be based on a simple average of the PPA price for the Ashtabula III wind project and the competitive bid price for the Merricourt wind project. The ALJ found that calculation most closely accords with Minn. Stat. § 216B.164, subd. 4(b). [16]

The ALJ's position was largely predicated on the 3rd sentence of Minn. Stat. § 216B.164, which he interpreted to require a competitive solicitation for any renewable energy facility seeking avoided cost pricing.[17] Because Merricourt had not yet been built but had pricing, and because Ashtabula III was relatively old and established, the ALJ decided a blend would result in a sufficient proxy for a new competitive solicitation. But he believed a competitive solicitation of some form was required.[18]

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[13] ORDER ESTABLISHING DATE OF LEGALLY ENFORCEABLE OBLIGATION, TERM LENGTH, AND AVOIDED COST OF ENERGY FOR THE RED LAKE FALLS HYBRID SOLAR/WIND PROJECT, Docket Nos. E-017/CG-16-1021 and E-017/CG-17-464, Doc. Id. 20185-143477-02 (May 31, 2018).
[14] *Id.* at 10.
[15] *Id.* at 3.
[16] *Id.* at 12.
[17] OAH - REPORT, OAH, Docket No. OAH 19-2500-34389, PUC E-017/CG-16-1021, Doc. Id. 201712-138448-01 at ¶ 233 (Dec. 27, 2017) (stating "The Administrative Law Judge reads the second sentence of Minn. Stat. § 216B.164, subd. 4(b), to give the MPUC the authority to set avoided cost rates for QFs. The third sentence of 4(b) instructs the MPUC on how to determine avoided costs for an R-QF. The Administrative Law Judge finds no reason to explore legislative intent as part of his analysis. If the MPUC can apply subdivision 4 to the facts before it, and in particular apply the third sentence of the subdivision according to its plain meaning without running afoul of federal law, the MPUC must do so, even if a conflict would arise under different facts.").
[18] *Id.*

However, the Commission did not accept the ALJ's position on the matter. Instead, the Commission opted to apply the second sentence of the statute to Red Lake Falls. According to the Order:

> Having considered the record and the last negotiating positions of the parties, the Commission will exercise the discretion accorded it under Minn. Stat. § 216B.164, subd. 4(b), to set avoided costs. The Commission will set the purchase price of energy per MWh for the Red Lake Falls hybrid solar/wind project equal to an estimate of avoided costs based on Otter Tail's 2017 Small Power Production Tariff filing of January 3, 2017.[19]

Thus, not only did the Commission disregard the ALJ's interpretation of Minn. Stat. § 216B.164, which is the same position Xcel seems to be asserting, but the Commission expressly agreed with Red Lake Falls in that the 3rd sentence of Minn. Stat. § 21B.164 was only intended to apply to how a competitive solicitation should transpire, if that option was selected. The Commission determined in *Red Lake Falls* that the statute authorized it to set the rates, if it so pleased, for renewable energy projects.

Red Lake Falls illustrates that even if Xcel is correct that Subd. 4 (b) should somehow apply to Attachment 6, the Commission has the ability to determine rates for QFs and renewable energy specifically. The Order stemming from that docket—and the simple fact that the Commission decided a rate different from the ALJ—definitively proves that there is no requirement that the Commission must predicate the avoided cost methodology of Attachment 6 on competitive solicitations for renewable projects.

D. Two Additional Reasons that Illustrate Why Minn. Stat. §216B.164 Should not Constrain a Revision of Attachment 6 or the DG Tariff

The "least cost renewable" limitation of Minn. Stat. §216B.164 Subd. 4 (b) should not limit the creation of a workable DG Tariff for two additional reasons: first, not all DG facilities employ renewable energy generation; second, the Commission and utilities have demonstrated that that limitation does not apply in practice.

First, *non-renewable* QFs between 1 MW and 10 MW that would seek to apply the DG Tariff also have the statutory right to a standard rate that incorporates the avoided cost of generation,

[19] Id. at 13 (emphasis added).

avoided capacity, line loss credits, and DG benefits. In these cases , like for a combined heat and power facility, the "least cost renewable" constraint—were it to apply at all—is moot.

Second, the Commission and utilities have demonstrated that the "least cost renewable" constraint need not be applied to *renewable* QFs either. In the case of Red Lake Falls, as discussed above, the Commission interpreted the statute in a way that minimized the role of the "least cost renewable" constraint to only how a competitive solicitation should transpire. Similarly, Xcel Energy has stated that, "A PPA can be evaluated on a customer-specific and site-specific basis, to determine eligibility, system reliability, capacity benefits, and impact on Company's transmission and distribution systems. […] Pursuant to state statute, Minn. Stat. § 216B.164, subd. 4, <u>the parties may negotiate</u> the full avoided capacity and energy costs in a PPA."[20] If it is in fact the case that the only price that should be given to the renewable energy facility is the lowest bid the utility has ever received, then there is no negotiation. The price is the price. However, Xcel acknowledges that the statute <u>permits</u> negotiation. This illustrates that even Xcel does not adhere strictly to the interpretation that they seem to be applying in practice, because negotiation would be precluded if sentence three of Minn. Stat. § 216B.164, subd. 4 were controlling

The overlap of the two statutes is confusing and leads to weird conclusions and inconsistent outcomes. There is no rational basis for applying Minn. Stat. § 216B.164, subd. 4 to Minn. Stat. § 216B.1611, and any decision rendering such a result would be arbitrary and capricious.

<u>III. Attachment 6 Needs To Be Revised In Only A Handful of Ways to Yield Viable Projects.</u>

According to the Commission's September 2004 Order, the DG Tariff's rate was meant to be an avoided cost rate—separate rates for avoided energy and avoided capacity costs—with additional compensation to DG facilities for non-energy benefits they provide to a utility. These include distribution credits, diversity credits, line loss credits, renewable credits, emission credits, and reliability credits. If done correctly Attachment 6 should yield a DG Tariff rate that is essentially an "avoided-cost plus" distribution and environmental benefits price, which will hopefully result in real-world DG projects while protecting the ratepayers from cross-subsidization. This is a similar concept to the value of solar. But because we cannot see the rates, it is our general understanding that thus far the DG Tariff rates have been commensurate with the utility's avoided cost. This is why no facility has used a DG Tariff to date.

Given that customers have opted for basic avoided cost pricing, like Red Lake Falls for instance, the current Attachment 6 methodology and the DG Tariffs that are calculated therefrom are

[20] Xcel Energy Answer to MnSEIA Information Request 9 (emphasis added).

effectively an “avoided-cost minus.” Developers are opting for other options besides the utility DG Tariffs, because they are more financeable than the tariffs designed for these types of projects. Our hope through this revisionary process is to correct the challenges of the current Attachment 6 methodology, and better align it with the original vision of a value based “avoided-cost plus” outcome.

Our recommendations for Attachment 6 modifications are below and will be filed in conjunction with these comments with both a clean and tracked changes version, and are entitled Appendix A and Appendix B respectively.

A. Attachment 6’s Line Loss Credits Should Also Be Based on System-Wide Line-Loss Rates

Right now, to provide any credits for avoided line losses, Attachment 6 requires that a facility study be conducted to estimate the avoided line losses as a result of purchases from a DG project. However, the cost of such a study almost outweighs any potential line loss credits it could earn. As a result, on information and belief, line loss credits have never been afforded to a project taking service under the DG Tariff.[21]

To ensure line loss credits are afforded, there should be an alternative method of calculating line loss credits. Joint Movants’ proposed changes to Attachment 6 (attached to their March 23, 2018 Motion), included a proposed method of providing line loss credits using the system-wide line losses for each electric utility. Each utility calculates its system-wide line losses, and those can be used to represent the line losses avoided by purchasing from a DG project. A simple, transparent, and universal method of calculating line loss credits is necessary for any potential DG project to actually obtain such credits. The method proposed by Joint Movants meets all of those requirements, and is similar to the existing approach in the VOS.[22]

B. To Better Align Avoided Capacity Costs with Integrated Resource Planning, Capacity Cost Calculations Should be Aligned with 15, not 5 year periods

As the Joint Movants have argued, the 5 year periods prescribed by Attachment 6 are an inadequate period of time to measure capacity deficits. The 5 year peek into needed capacity is misaligned with both how the utility—and the Commission, and stakeholders—plans for new capacity, and is also misaligned with the useful life of most distributed generation assets.

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[21] *See also*, utility answers to MnSEIA Information Request 5.

[22] *See* ORDER APPROVING DISTRIBUTED SOLAR VALUE METHODOLOGY, In the Matter of Establishing a Distributed Solar Value Methodology under Minn. Stat. § 216B.164, subd. 10 (e) and (f), Docket No. E-999/M-14-65, Doc. Id. 20144-97879-01 at 7-10 (April 1, 2014).

However, we acknowledge that Integrated Resource Planning, however, generally looks 15 years into the future, which may require capacity pricing to be made on a 15 year look ahead instead of a full contract term duration. Thus our preferred approach would be to incorporate a fair price for estimated capacity for each year of the contract life, and would require an understanding of capacity needs 25 years out. But we are recommending a 15 year look ahead, annualizing the capacity value, and adding that valuation to each year of the contract even if the contract exceeds 15 years.

Allotting value to a DG project based on this shorter 5 year time frame is discriminatory and counter to the purposes of Minn. Stat. § 216B.1611.[23] Using a 5 year look ahead, as the current Attachment 6 requires, frequently results in a $0 valuation for capacity for the entire length of the contract, so long as the utility is adding capacity before it has near-term needs. This is almost always the case.

Attachment 6 is discriminatory in its current form because the avoided cost capacity credit for the sixth year and beyond is not included in the hypothetical contract for an asset under this Tariff, despite there almost always being some value for excess capacity in the MISO market. By contrast, utility-owned assets are rate-based for the life of the asset. This discrimination does not reflect differences in technology or generation profile, but rather reflects a reticence on the part of utilities to provide a workable DG Tariff as described by Minn. Stat. § 216B.1611.

Furthermore, the 5 year look ahead for capacity needs required by Attachment 6 falls short of legislative intent in that it is inconsistent with the operating characteristics of wind and solar facilities. That statute requires that the Commission establish standards for utility tariffs that fit the technology used:

> […] At a minimum, these tariff standards must: […]
> (3) take into account differing system requirements and hardware, as well as the overall demand load requirements of individual utilities;
> (4) all for reasonable terms and conditions, consistent with the cost and operating characteristics of the various technologies, so that a utility can reasonably be assured of the reliable, safe, and efficient operation of the interconnected equipment; […][24]

Because the system life—the "operating characteristics"—of a solar photovoltaic system, for instance, generally runs 25 years or more, "reasonable terms and conditions" of the capacity credit should take into account the effect that the DG facility will have on capacity through the

[23] Minn. Stat. 216B.1611 Subd. 1 and 3.
[24] Minn. Stat. 216B.1611 Subd. 2 (a) (3) and (4).

end of its useful life—or at least the end of the contract. If the DG facility is providing the utility capacity, the utility should be compensating the DG facility for the capacity, because it is of some value to the utility until spot capacity pricing from MISO is routinely negative. Since all common DG facilities provide capacity during their entire useful life, then the utility should provide compensation for the added capacity for the entirety of the contract term and that capacity value should be as close to a real world avoided cost as Integrated Resource Planning and utility modelling allows.

C. Contract Length Should Reflect Operating Characteristics of the Technology Deployed to Encourage Financeability and Fairness

The current tariffs that arise from Attachment 6 of the 2004 Order fall short of the statutory intent of Minn. Stat. § 216B.1611, in part because there is no term-length requirement as part of Attachment 6. Currently, each utility's DG Tariff either calls for individual power purchase agreements ("PPAs") with varying negotiated terms, or reset each year.[25] These contract terms are unreasonable and counter to statute. These contract terms are unreasonable for two reasons—first, the uncertainty means that DG facility contracts will be unfinanceable, and second, because they are inconsistent with the characteristics of distributed generation technologies.

First, a rate that varies year-on-year based on annual recalculations is unpredictable, and therefore unfinanceable, unless the estimated value is very high. A rate that is determined by "'mutually agreeable arrangement' regarding the term of the agreement,"[26] may be financeable within the boundaries of an individual project agreement, but is not standard. Minn. Stat. § 216B.1611 was created to help streamline projects, but negotiating every agreement results in wildly disparate project outcomes.

Second, contract term lengths allowed by current utility DG Tariffs are inconsistent with the cost and operating characteristics of modern DG facilities. For example, Community Solar Gardens are contracted for 25 years through the VOST.[27] The Red Lake Falls facility, which utilizes both solar and wind technologies, was ultimately ordered a 20 year contract term length. These

[25] *See* MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2, Section 10, Sheet 78, found at https://www.xcelenergy.com/staticfiles/xe-responsive/Company/Rates%20&%20Regulations/Rate%20Cases/Me_Section_10.pdf; Minnesota Power Electric Rate Book - Volume I, Section V, Page No. 82, found at https://www.mnpower.com/CustomerService/RateBook; Otter Tail Power Company, Electric Rate Schedule, Section 12.04, Distributed Generation Service Rider, at 5; Dakota Electric Association Ratebook; *See also*, utility answers to Information Request 10.

[26] *See* Otter Tail Power Company answer to MnSEIA Information Request 10.

[27] See MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2, Section 9, Sheet 64 at https://www.xcelenergy.com/staticfiles/xe-responsive/Company/Rates%20&%20Regulations/Me_Section_9.pdf

contract term lengths recognize the expected lifetime of the solar equipment at those facilities, and should inform the revision of Attachment 6.

Lastly, utilities tend to get 25-year contracts, which is a fact that the Commission and the ALJ relied on in the *Red Lake Falls* docket. Independent projects arising from the DG Tariff should be entitled to similar financing arrangements as utility projects, including long-term contract options.

D. <u>The onsite requirement in Attachment 6 is archaic, and superseded by both Commission Order and industry practice</u>

The onsite requirement of Attachment 6 is no longer necessary, given the breadth and scope of the Interconnection Standards, and by the ways in which they are employed. The Commission has already approved, in concept, the idea of stand-alone generators that interconnect with utility distribution systems, and has thus set precedent that the generation facility need not serve on-site load.

Attachment 6, as it currently reads, requires in the "QUALIFICATIONS" section, that "The DG facility must be an operable, permanently installed or mobile generation facility <u>serving the customer receiving retail electric service at the same site</u>."[28] Joint Movants have argued that this requirement is no longer necessary.[29] The Commission implicitly agreed when it updated the Interconnection Standards in this docket. The close statutory relationship between the Interconnection Standards and the DG Tariff—which are respectively required by Minn. Stat. § 216B.1611 subd. 2 and subd. 3—further supports the premise that if the Interconnection Standards do not require onsite load, that a workable and statutorily correct DG Tariff operating within those confine should also not require onsite load.

In order to codify and standardize interconnection practices across the state, the Commission authorized the creation of the State of Minnesota Distributed Energy Resources Interconnection Process ("MN DIP").[30] The MN DIP succeeds the archaic requirement of Attachment 6 for onsite generation when it accounts for the possibility of a "Stand-alone generator" in the Pre-Application Report. MN DIP § 1.4.1.7.

Furthermore, in practice, Xcel Energy interconnects "Stand-alone generators" on a frequent basis. Community Solar Gardens operating under Xcel's Solar*Rewards Community program

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[28] *See* Attachment 6 (Emphasis added).
[29] *See* Joint Movants Motion, March 23, 2018, Exhibit B at 7.
[30] *See* ORDER APPROVING TARIFFS WITH MODIFICATIONS AND REQUIRING COMPLIANCE FILINGS, Docket No. E-999/CI-16-521, Doc. Id 20194-152158-04 (April 19, 2019).

serve only nominal station service load before interconnection with the point of common coupling. Those facilities are also subject to the requirements of Minn. Stat. § 216B.1611 as promulgated through MN DIP.

The justification that ties the current practices of what appear to be stand alone generators to the new MN DIP and the on-site requirements of Minn. Stat. § 216B.1611 is the concept of "house power," or the need to pull a minor amount of retail electric service for a DG Facility to operate continuously. Acknowledging that house power creates a buy/sell relationship between the utility and the facility, and thus constitutes an "on-site" system in the most basic sense is a way to keep common practice aligned with statute.

From the perspective of the utility-grid this small amount of natural load due to house power is no different than placing a DG system next to a minor load consuming customer, and therefore it does not seem necessary to limit the utilization of the DG Tariff to facilities that are adjacent to existing retail customers. A need for house power makes any interconnected DG facility a retail customer. Thus, even if the Commission determines that the on-site requirement is necessary to meet statute, taking retail house power should be sufficient to render a DG facility as "on-site" for Minn. Stat. § 216B.1611.

E. <u>A Workable DG Tariff should appropriately value Diversity and Reliability Credits</u>

The September 2004 Order also contains what appear to be mistakes or not fully fleshed- out concepts, which require revisiting in their own right. Under the topic of "Diversity Credits," the Commission concludes that "No additional diversity credits for energy and capacity should be given to DG customers who contract for standby service."[31] But, the Commission does not allude to whether it should permit Diversity Credits for traditional, non-standby systems. In fact, it suggests that Diversity Credits should be applied, but makes no definitive statement one way or another, nor does it truly define how a utility should value DG diversity benefits and added grid resiliency.

No utility has interpreted this language to allow for or require Diversity or Reliability Credits, as it is not present in any of their DG tariffs. A revised DG Tariff should ensure that Diversity and Reliability Credits are included in any applicable rates.

We suggest to the Commission that Diversity & Reliability Credits should be provided for customers that are not on standby service, and should reflect the amount of reserve capacity it

[31] Attachment 6, § 9 (c) (i).

requires to back up a supply of electricity from smaller generators. This figure can be determined using an effective load carrying capability measurement, which may be modeled for the average DG generator the utility expects to receive under this tariff, or a Peak Load Reduction approach, which takes the maximum distribution load over the Load Analysis Period minus the maximum distribution load over the Load Analysis Period.

F. <u>The DG Tariff should include Distribution Credits that account for both long- and short-run avoided distribution costs resulting from DG.</u>

Attachment 6 states that distribution credits to DG customers should equal the utility's avoided distribution costs resulting from the installation facility. But Attachment 6 requires that the utility perform a screening study (at the customer's expense) to determine if a DG project has the potential to receive distribution credits based on the utility's list of substation areas or feeders that "could be likely candidates for distribution credits as determined through the utility's normal distribution planning process."[32] That framework does not provide transparency into the utility's process for identifying candidates for distribution credits; puts the burden of conducting a distribution benefit study on individual DG projects; and likely underestimates the avoided distribution costs associated with DG projects by focusing on the utility's distribution planning process (which may forecast only short-term distribution grid needs) to the exclusion of avoided costs over the lifetime of a DG project (which can be over 25 years).

We recommend that distribution credits account for both long-run system-wide avoided distribution capacity costs as well as short-run locational avoided capacity costs.

The long-run value represents a "counterfactual" estimate of what it would have cost to add system capacity in the absence of DER. This value ("unspecified deferral value") is in addition to location-specific values that defer specific upgrades (some jurisdictions refer to this value as "specified deferral value").

These costs are described by California Public Utilities Commission in its avoided cost framework.[33] Specified deferral value is quantified to determine how DER installations at a particular location can defer specific utility investments and is used to inform specific utility DER/non-wires alternative procurements. Unspecified deferral value is currently being used and refined to determine how DER can avoid unanticipated grid needs and is characterized by

[32] Attachment 6 at 5 order point 8bii.

[33] Cal. Pub. Util. Comm'n, Rulemaking 14-08-013 et al. Decision 20-03-005, Decision Adopting Staff Proposal on Avoided Cost and Locational Granularity of Transmission and Distribution and Deferral Values; California Public Utilities Commission at 6 (March 12, 2020) (available at https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M329/K723/329723941.PDF.)

system-wide (or by climate zone) values that are used to inform customer DER programs (such as energy efficiency portfolios or net energy metering).

There has been a considerable amount of time and effort in the VOS docket (13-867) to set an avoided distribution system capacity calculation methodology that accurately and fairly values such costs. While the broader application of the VOS methodology will be discussed below, we believe that the work that has been done in avoided distribution costs is directly applicable to the DG Tariff model.

In particular, the methodology for calculating the locational value in the avoided distribution cost component of VOS is currently the subject of a stakeholder process. Once completed, that methodology could provide a reasonable and fair approach to locational valuation that could be applied in this case. In their May 5, 2020 letter to the Commission filed in the VOS docket, Professor Gabe Chan and his colleagues at the University of Minnesota Matthew Grimley and Bixuan Sun laid out a framework approach to calculating avoided distribution system capacity costs that balances the competing goals of accuracy with benefits/practicality.[34]

Assuming that the approach recommended by Dr. Chan et al is adopted for Xcel's VOS calculation, it could then be applied directly as the Attachment 6 Distribution Credit calculation. Other utilities could then be directed to calculate and establish distribution credit values using the same methodology (accounting for both long- and short-run avoided costs). Those Distribution Credit values should then be made transparently available, so that each DG project does not have to bear the expense of a new study into avoided distribution costs.

G. The DG Tariff could value different generation profiles, and should require that the utility purchase Renewable Energy Credits from the Customer at the Customer's Discretion

If the Commission would like to apply generation specific avoided costs, then a simple, yet appropriate way to do that would be to 1) recognize differing capacity values based on the time of generation from distributed assets, rewarding the DG assets with a specific capacity value based on the delivery of capacity to the utility when needed, and 2) ensure that the Tariff also credits DG assets for the value of Renewable Energy Credits at a fair price. These two elements when taken together would ensure that facilities that quality for the DG Tariff would be compensated for the benefit to the utility's capacity constraints, and that the value of green power is sufficiently incorporated into the final PPA price.

1. **Time of Generation is Technology Specific**

[34] *See* COMMENTS, GABRIEL CHAN, Docket No.E002/ M-13-876, Doc. Id. 20204-162506-03 (May 5, 2020).

Some DG resources, like solar photovoltaics and wind, are intermittent and non-dispatchable, but nonetheless broadly predictable as to the time of generation. The time value of that generation is recognized elsewhere. For example, the Commission's implementation of the VOST as described in 216B.164 Subd. 10 (8) (f) recognizes the value of solar generation at times where the load profile of the utility is at or close to peak.

If the DG facility is likely to reduce the load profile of the service territory of the utility, and thus reduce the need for capacity at peak generation, then the displacement of peak generation capacity should be reflected in the capacity credit incorporated into the DG Tariff. This same principle was central to the original formulation of Xcel Energy's Capacity Credit, and could be applied to all types of DG generation.

This would also incent intermittent resources to invest in storage technologies to produce firmer power, making them become true Distributed Energy Resources (DERs) that can be called upon during capacity constrained periods even if the utility's peak period changes over time. It would also reward traditionally firm power producers, like hydro or combined heat and power, for their consistent and reliable power production. This incentive alone should be sufficient to encourage facilities with firmer power generation, which is more valuable to the utility, over intermittent resources. It is a very basic way to create time- and resource-based pricing predicated on benefit to the utility.

2. Renewable DG Assets Should be Compensated with Renewable Energy Credits

Renewable Energy should also be considered more valuable than fossil fuel based power given Minnesota's existing laws. In general, generators using renewable energy technologies as described in Minn. Stat. § 216B.1691 accumulate renewable energy credits (RECs), which can be used to satisfy the renewable energy standard requirements or goals of that same statute.

Attachment 6 requires an update to conform to the renewable energy standards and credit-tracking mechanisms of § 216B.1691. Attachment 6, which was ordered in 2004, predates the renewable energy standard and the statutory mandate to create "a program for tradable renewable energy credits for electricity generated by eligible energy technology," which became law in 2007. Minn. Stat. § 216B.1691 Subd. 4. (a). It also predates the solar energy standard introduced in Minn. Stat. § 216B.1691 Subd. 2f.

If a utility would seek to apply generation from renewable DG Tariff facilities toward compliance with the current or future renewable energy standard, then the facility should be paid a rate based on those technology-specific values. Similarly, a DG facility that allows the utility to avoid building or purchasing from a solar energy facility should be paid a rate based on those technology-specific avoided costs. If a purchase of energy derived from solar photovoltaic DG facilities results in a utility meeting a solar-specific energy standard or goal, then the utility should offer the facility the avoided cost of purchasing the solar-derived REC on the open market. One approach the Commission should consider that would standardize that avoided cost would be to offer the facility the average cost of a solar REC at the time of interconnection.

Consistent with the original Attachment 6, a DG facility should have the option to retain the RECs it generates.

This approach is different from what we recommended in our initial redline of Attachment 6, especially in regards to calculating capacity valuations. However, we offer it as an alternative, if the Commission is interested in exploring this approach.

H. An Alternative Pathway to Modifying Attachment 6.

The above approach to reforming Attachment 6 is our preferred pathway. We would prefer to take the existing Attachment 6 and make a few minor modifications that should result in workable tariff rates for DG deployment, while protecting ratepayers from cross-subsidization. However, we do want to be cognizant of alternative ways to achieve similar results that the Commission may prefer.

Another approach that would utilize existing work would be to 1) take the Value of Solar methodology, 2) strip out the Avoided Environmental Cost, 3) recalculate it for the specific DG generator type that is applying for interconnection, and 4) offer a market rate for Renewable Energy Certificates, if the applying facility is a renewable energy generator. This approach would yield an "avoided-cost plus" outcome that fairly captures the true value of the generator to the utility, it would do so without ratepayer cross-subsidization, and would utilize an existing and time tested methodology in the VOS.

This approach could be a reasonable substitute for all the DG benefit modifications that we mention above and would yield technology-specific DG Tariffs. Clearly a modified VOS would work for solar generation, which is the generator type we would expect would most frequently partake in a DG Tariff program. The utilities or the generator could, however, still petition the Commission for clarification in instances when a different generator type does not squarely fit into the adopted methodology. We offer this as an alternative pathway to accomplishing what we believe would result in a similar outcome.

Conclusion

Here we outlined that the utilities' implementation of their DG Tariffs has thus far been unreasonable, because they have required undue project development prior to getting real DG Tariff rates. We also argued that the DG Tariff and DG interconnection standards are governed by Minn. Stat. § 216B.1611, and the limitations of § 216B.164 do not apply.

Finally, n order to facilitate DG projects in accordance with statutory intent, the revised guidance for the DG Tariff and incorporated rates should: 1) be publicly available and transparent to the extent possible; 2) incorporate system-wide line-loss rates; 3) be consistent with integrated resource planning norms for the purposes of calculating capacity credits; 4) employ contract lengths appropriate to the deployed technology; 5) reflect generation profiles of the technology employed; 6) compensate renewable facilities with market-rate REC prices; and, 7) ensure appropriate and reasonable utility implementation.

Thank you for your consideration of this critical item to Minnesota's distributed generation future.

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