MINNESOTA
PUBLIC UTILITIES COMMISSION

Staff Briefing Papers

Meeting Date	August 10, 2023	Agenda Item **3
Company	All Electric Utilities	
Docket No.	E999/CI-16-521	
	In the Matter of Updating Generic Standards for Utility Tariffs for Interconnection and Operation of Distributed Generation Facilities Under Minn. Stat. §216B.1611	
Issues	Should the Commission revise or replace Attachment 6 of the September 28, 2004, Order in Docket No. E999/CI-01-1023 which creates guidelines for establishing the terms of the financial relationship between an electric utility and a distributed generation customer with no more than 10 MW of capacity?	

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✓ **Relevant Documents**	**Date**
Commission Order Establishing Workgroup and Process to Update and Improve State Interconnection Standards	January 24, 2017
Xcel Compliance Filing	June 17, 2019
Otter Tail Power Compliance Filing	June 17, 2019
Minnesota Power Compliance Filing	June 17, 2019
Fresh Energy, Comments and Attachment	August 5, 2020
MnSEIA, Comments	August 5, 2020

Relevant Documents	Date
Department of Commerce, Comments	October 29, 2020
Joint Comments (MnSEIA, ELPC, Fresh Energy, VS)	October 30, 2020
Tracked Changes Att. 6 Revisions (MnSEIA, ELPC, Fresh Energy, VS)	October 30, 2020
Otter Tail Power, Comments	October 30, 2020
Xcel Energy, Comments	October 30, 2020
Dakota Electric Association, Comments	October 30, 2020
Joint Comments (Midwest Cogeneration Association, Heat is Power)	October 30, 2020
Minnesota Rural Electric Association, Comments	October 30, 2020
Minnesota Power, Comments	April 30, 2021
Joint Reply Comments (MnSEIA, ELPC, Fresh Energy, ELPC)	May 20, 2021
Xcel Energy, Reply Comments	May 20, 2021
Dakota Electric Association, Reply Comments	May 20, 2021
Department of Commerce, Reply Comments	May 20, 2021
Department of Commerce, Supplemental Comments	September 28, 2022
Joint Comments (MnSEIA, ELPC, VS)	September 28, 2022
Xcel Energy, Comments	September 28, 2022
Dakota Electric Association, Comments	September 28, 2022
Otter Tail Power, Comments	September 28, 2022
Joint Reply Comments (MnSEIA, ELPC, VS)	October 18, 2022
Minnesota Power, Reply Comments	October 18, 2022
City of Minneapolis, Reply Comments	October 18, 2022
Referenced Documents, Previously Before the Commission	
Commission Order Approving Xcel's 2021 Value-of-Solar Rate in 13-867	March 9, 2021.
Commission Order Authorizing Further Proceedings	March 19, 2019
Commission Order in Docket CG-16-1021	May 31, 2018
Commission Order Establishing Standards in CI-01-1023	September 28, 2004

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BACKGROUND

Issues Statement

The Commission is to consider whether to revise or replace Attachment 6 of the September 28, 2004, Order in Docket No. E999/CI-01-1023 which creates guidelines for establishing the terms of the financial relationship between an electric utility and a distributed generation customer with no more than 10 MW capacity.

Overview

On September 28, 2004, the Commission issued its Order Establishing Standards in Docket No. E999/CI-01-1023. This Order established the interconnection process, technical requirements, standard Interconnection Agreement, and methodology for calculating rates for Distributed Generation (DG) Systems.

In 2016, the Commission commenced the current proceeding to update the generic standards for the interconnection and operation of DG facilities established under Minn. Stat. §216B.1611. The Commission updated the statewide interconnection standards for DG which is now known as the Minnesota Distributed Energy Resource Interconnection Process and Agreement (MN DIP and MN DIA) through its Order Establishing Updated Interconnection Process and Standard Interconnection Agreement (August 13, 2018), and Order Establishing Updated Interconnection and Interoperability Requirements (January 22, 2020).

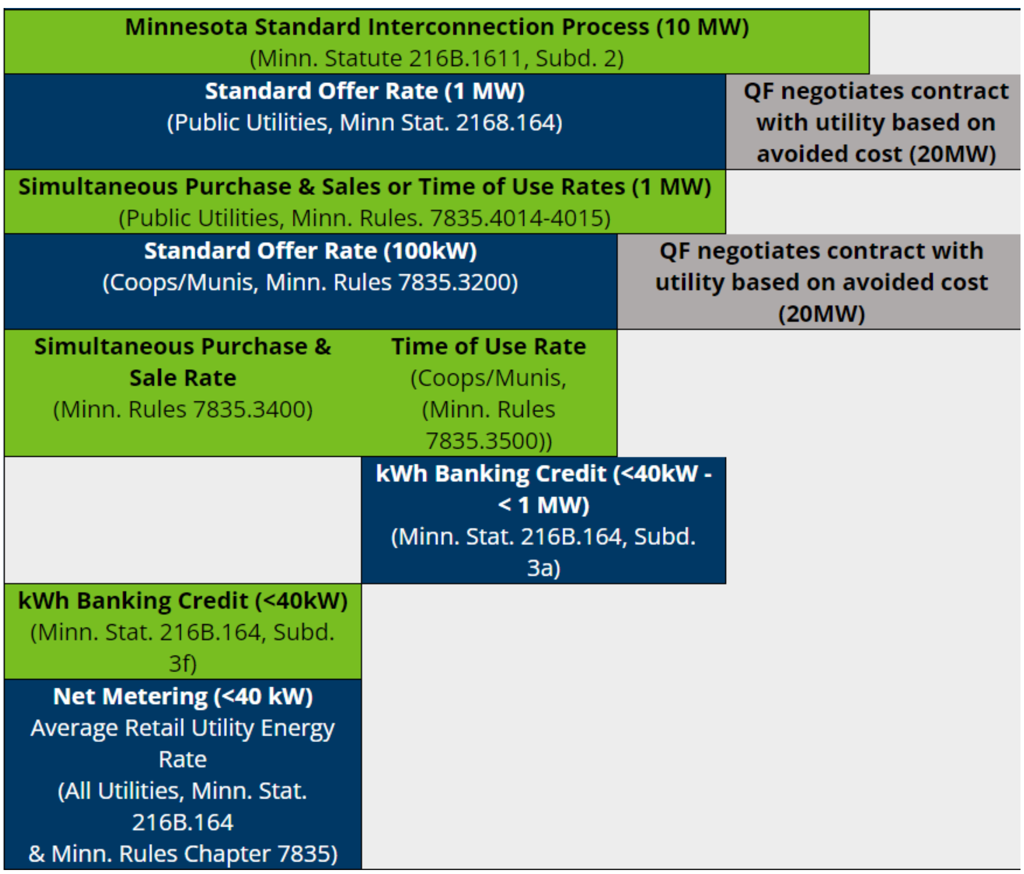
The Commission's January 24, 2017, Order in this docket established the Distributed Generation Workgroup and process to update and improve the statewide interconnection standards in Docket No. E999/CI-16-521. The Order described updating Attachments 1 -5 of the September 28, 2004, Order in E999/CI-01-1023 in two phases: Phase I (Attachments 1, 3-5 covering statewide process, application forms, and agreements) and Phase II (Attachment 2 covering statewide technical requirements.) The Order did not address Attachment 6; thus, rates were considered out of scope in Phase I and II.

The MN DIP recognizes that "until updated or replaced" Attachment 6 from the Commission's September 28, 2004, Order in Docket No. E999/CI-01-1023 remains in effect as part of the current statewide interconnection standards. Attachment 6 is titled "Guidelines for Establishing the Terms of the Financial Relationship Between an Electric Utility and Distributed Generation

Customer with No More than 10 MW of Capacity." Staff has included Att. 6 as Att. A.

<u>Related Statutes</u>
Minn. Stat. §216B.1611 establishes statewide interconnection standards for the terms and conditions governing the interconnection and parallel operation of on-site distributed generation of no more than 10 MW capacity. Minn. Stat. §216B.1611, Subd. 3 requires public utilities to file distributed generation (DG) tariffs consistent with that order and for municipal and cooperative utilities to adopt DG tariffs that address the issues in the Commission's order.

Minn. Stat. §216B.164 implements the Public Utility Regulatory Policies Act of 1978 (PURPA), as amended, in coordination with the Minn. Rule Ch. 7835, and is intended "to give the maximum possible encouragement to cogeneration and small power production consistent with protection of the ratepayers and the public."[1] Both outline cogeneration and small power production (i.e. distributed generation) rate design among other topics. In Minnesota, there are several DG rate categories as displayed on this chart on the PUC website[2]:



[1] Minn. Stat. 216B.164; Subd. 1-2 and Minn. Rule 7835.0200.

[2] Accessed online: https://mn.gov/puc/activities/economic-analysis/distributed-energy/

Minn. Stat. §216B.1641, which was amended in 2023, establishes Community Solar Garden programs for Xcel Energy customers with specific guidance to the Commission on how to set the rates for these DG projects.

Minn. Stat. §216B.1691 establishes Minnesota's renewable energy and solar energy standards, and was amended in 2023 creating a 100% carbon free standard and, for public utilities, a Distributed Solar Energy Standard utilizing a competitive bidding procurement.

<u>Record to Date</u>
On March 27, 2018, Minnesota Solar Energy Industry Association (MnSEIA) et al. filed a request to consider updating Att. 6 in this docket.[3]

On March 19, 2019, the Commission issued its Order Authorizing Further Proceedings, authorizing a comment period for considering possible updates to Att. 6 addressing the following, while specifically excluding establishment of fixed rates:

a. The consistency of Att. 6 with existing statute and rules (e.g. Minn. Stat. §§ 216B.1611 and .164 and Minn. R. ch. 7835);
b. For facilities between 1 and 10 MW, guidance on ensuring adequate transparency of negotiated rates and availability or consideration of Att. 6 credits;
c. Better alignment of avoided capacity costs with Integrated Resources Planning and other regulatory proceedings: and
d. Guidance that recognizes technology, location and time-specific avoided cost considerations.

On June 17, 2019, Minnesota's four rate-regulated electric utilities (Xcel Energy, Minnesota Power, Otter Tail Power, and Dakota Electric Association) filed responses to order paragraph 3 of the March 19, 2019, Order with a description of how each utility calculated its DG tariffed and negotiated rates.

On July 16, 2020, the Federal Energy Regulatory Commission (FERC) adopted Order No. 872 addressing Qualifying Facility Rates and Requirements Implementation Issues Under PURPA. The PURPA reform addressed avoided cost ratemaking among other topics. On November 19, 2020, FERC adopted Order no. 872-A addressing arguments on rehearing and clarifying Order No. 872.[4]

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[3] The Environmental Law and Policy Center, the Institute for Local Self Reliance, the Minnesota Center for Environmental Advocacy, Minnesota Brownfields, and Clean Energy Economy Minnesota also filed with MnSEIA.

[4] FERC, Order 872 (July 16, 2020), Docket Nos. RM19-15-000 and AD 16-16-000, accessible online: https://www.ferc.gov/sites/default/files/2020-07/07-2020-E-1.pdf. Order 872-A (November 19, 2020), accessible as word download: https://elibrary.ferc.gov/eLibrary/filedownload?fileid=15662892.

On August 28, 2020, the Commission issued a Notice of Comment period to address the issue of updates to DG rate guidance provided in Att. 6. The initial period was extended to October 30, 2020.

The Institute for Local Self-Reliance filed comments on September 30, 2020. On or around October 30, 2020, the Department of Commerce, Division of Energy Resources Division (Department), Sundial Energy, Xcel Energy, Midwest Cogeneration Association & Heat is Power Association (MCA/HiP), Otter Tail Power Company, MnSEIA, Vote Solar (VS), Fresh Energy, the Environmental Law and Policy Center (ELPC), Minnesota Rural Electric Association, and Dakota Electric Association filed comments. Alongside joint comments, MnSEIA, ELPC, Fresh Energy, and VS ("Joint Commenters") filed a proposal with red-lined revisions to Attachment 6 on October 30, 2020.

On October 28, 2020, the Department recommended the Commission institute a six-month extension in the review of Att. 6. The initial comment period was again extended to April 30, 2021.

Minnesota Power and Otter Tail Power filed Comments on April 30, 2022. The Joint Commenters, Xcel Energy, the Department, and the Dakota Electric Association, filed reply comments on or around May 20, 2021.

On August 29, 2022, the Commission issued a supplemental notice of comment period inquiring whether parties had any updates to their position with respect to this issue.

On September 28, 2022, the Joint Commenters, Xcel, Otter Tail Power, Dakota Electric, and the Department filed supplemental comments.

On October 18, 2022, the Joint Commenters, Minnesota Power, the City of Minneapolis, and Xcel filed supplemental reply comments.

Positions of the Parties

<u>Joint Commenters (MnSEIA, ELPC, VS, Fresh Energy)</u>

The Joint Commenters request that Minnesota's current DG tariffs under Att. 6 and governing order be updated and the incorporated rates:

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 renewable energy credit (REC) prices; and,
7) ensure appropriate and reasonable utility implementation.[5]

In their October 18, 2022, reply comments, the Joint Commenters responded to the Department's recommendation to first resolve the legal questions that stakeholders highlighted regarding Minn. Stat. §§ 216B.1611 and 216B.164 before addressing Att. 6 revisions and argued that the record is sufficiently well-developed to consider revisions at this time.

The Joint Commenters recommend that if the Commission does not adopt their proposed Att. 6. red-lined revisions as filed on October 30, 2020, they support (1) a finding that the correct enabling statute is Minn. Stat. §216B.1611, and not §216B.164, Subd. 4, and (2) the issuance of a limited new comment period that prescribes a process designed to result in a final Commission order within a reasonable timeframe of 90-180 days under this shared understanding of policy implications. Throughout the record, the Joint Commenters stressed that to their knowledge, no DG facility has used a utility's DG tariff based on the current Att. 6 in Minnesota and argued that this fact, among others, necessitates Commission action and Att. 6 revision.[6] The Joint Commenters' proposed redline edits to Att. 6 are included as Att. B.

<u>Department</u>
On May 20, 2021, the Department filed reply comments recommending that the Commission first evaluate areas where federal rules and statutes conflict with existing Att. 6 requirements and undertake additional comments from stakeholders towards this end. In the second step, the Commission would then consider additional updates to Att. 6 beyond those required to align with federal and state law, developing the record as needed.

Lastly, the Department recommends the Commission explore the possible use of MISO market pricing for capacity needs to inform distributed generation pricing and procedures for increasing transparency for DG-related pricing processes.

The Department's September 28, 2022, comments also expressed interest in seeing the Commission time this proceeding so that important information regarding the implementation of Advanced Metering Infrastructure (AMI) meters and IEEE 1547- 2018 compliant advanced inverter roll out anticipated in 2023 is available to inform parties' work. The Department

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[5] Joint Commenter Comments, October 30, 2020, at 21.

[6] Staff understands parties' reference to no DG taking service under a utility's DG Tariff to mean using the Att. 6 language in a utility's tariff for above 1 MW projects. As of December 2022, Minnesota had 18,792 interconnected systems totaling 1.38 GW of installed capacity receiving utility compensation under a tariff (e.g. net metering, community solar gardens, and other standard offer rates) or negotiated rates.

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indicated that increased visibility and transparency afforded by the rollout of these advancements can impact discussion on required changes to Att. 6 after first addressing the presence of any conflicts with state and federal law.

Xcel Energy

In the September 19, 2018, initial comments, Xcel argued that the existing Commission process set forth in the 2004 Order—to implement Att. 6 through tariff filings—has allowed for all interested parties to raise issues related to ratemaking, compensation for DG, and ratepayer impacts sufficiently. However, in its October 30, 2020, comments, Xcel stated that due to the then upcoming revisions to PURPA[7], Att. 6 is no longer consistent with Minn. Stat. §§ 216B.1611 and 216B.164, or with Minn. Rules Ch. 7835 and presented arguments surrounding inconsistencies regarding: the size of the resources to which Att. 6 should apply, cost and benefits in setting rates, methodology for calculating avoided energy and capacity costs, the terms relevant to standby service, and whether specific renewable avoided cost rates must be offered.

In its May 2021, comments, Xcel provided a response to the initial comments from the Department, Joint Commenters, and MCA/HiP. Xcel generally agreed with the Department's suggestion that the modification of Att. 6 be transparent, understandable, and practical to administer through utility tariffs in consideration of other DG customers not contracted with Xcel under the auspices of Att. 6. Xcel also provided specific input on customers' access to rate information, legal issues regarding the applicability of statute and prior cases, and the proposed revisions from the Joint Commenters and MCA/HiP.

In its September 28, 2022, comments, Xcel did not make any additional updates to its position but noted that since the time Att. 6 was developed in 2004, there have been several relevant changes to applicable law and regulation by state statute, state rules, MN PUC Orders and FERC regulations. Xcel noted three additional changes in response to the August 29, 2022, Notice of Comment:

(1) FERC's issuance of a June 29, 2021, Order terminating Xcel's mandatory purchase obligation for the new contracts or obligations from small power production facilities with net capacities greater than 5 MW;
(2) Increased quantity of DER interconnected and disproportionate extent to which Xcel has interconnected DER;
(3) Passage of the Inflation Reduction Act (IRA), which extends the Investment Tax Credit (ITC) and provides an option for Production Tax Credit (PTC) up to 2035.

Minnesota Power

Minnesota Power supports the recommendation in the Department's September 28, 2022,

[7]Qualifying Facility Rates and Requirements, Order No. 872, 172 FERC ¶ 61,041 (2020)

reply comments that the Commission first narrow its scope of inquiry to the legal questions and potential conflicts between the various state and federal statues and rules. Minnesota Power also agrees with the Department's suggestion that the Commission may want to consider timing this proceeding to utilize additional information around AMI meters and advanced inverters.

In its April 30, 2021, comments, Minnesota Power agreed with Xcel's October 30, 2020, comments on this issue, including the argument that Att. 6 is inconsistent with existing statute and rules, including in terms of the size of resources and considerations in setting rates. Minnesota Power also pointed to its June 17, 2019, compliance filing in this docket for guidance on ensuring adequate transparency of negotiated rates. Minnesota Power asserted that its current DG tariff rates are both reasonable and appropriate.

Finally, Minnesota Power stated in its April 30, 2021, comments that FERC Order 872-A, which clarifies FERC's original update to PURPA rules, does not appear to change any conclusions reached by Xcel. Minnesota Power additionally noted that the Company is considering following other utilities requesting FERC to lower their mandatory purchase obligations from 10MW to 5MW as allowed in the updated PURPA rules.[8]

Dakota Electric Association

In its October 30, 2020, comments, the Dakota Electric Association highlighted its unique position as the only rate-regulated electric cooperative in Minnesota and a full requirements customer of Great River Energy Cooperative (GRE). Dakota Electric Association's existing relationship with GRE and the associated tariffs governing DG purchases all comport with FERC's PURPA Qualifying Facility Joint Implementation Plan. Dakota Electric Association otherwise did not take an explicit stance or comment on issues on the record.

Otter Tail Power

In its September 28, 2022, comments, Otter Tail Power (OTP) stated it does not believe changes to Att. 6 are necessary. OTP also asserted that its DG rates are developed in a consistent manner, are transparent to the greatest extent possible, are properly aligned with integrated resource plans, and allow for technology, location and time-specific avoided-cost considerations."[9]

City of Minneapolis

On October 19, 2022, the City of Minneapolis ("the City") filed reply comments requesting the Commission address the issues identified by the Joint Commenters and modify Att. 6 to allow market-driven renewable energy development consistent with the spirit of Minn. Stat.

[8] Staff notes it is unclear if Minnesota Power has made this request in the subsequent years.

[9] OTP Comments filed September 28, 2022, at 2.

§216B.1611. Additionally, the City would support adoption of the Joint Commenters' proposed red-line modifications to Att. 6, which would obligate Xcel Energy to update its DG tariff.[10]

Midwest Cogeneration Association and Heat is Power Association

MCA and HiP jointly filed comments that largely align with the stances of the Joint Commenters, though MCA and HiP did not participate in the most recent period of record development following the August 29, 2022, notice of supplemental comment period. In their October 30, 2020, comments, MCA and HiP request that the Commission amend Att. 6 to reflect that utilities cannot apply avoided cost rates using methodology from other statutes for DG resources, such as that from §216B.164. They also request that the Commission:

(1) Edit Att. 6 to increase transparency on the calculation of avoided costs and better align avoided capacity costs with Integrated Resource Planning and other proceedings,
(2) Convene a stakeholder workgroup to make recommendations for technology, location, and time-specific avoided cost considerations,
(3) Revise Att. 6 to clarify how it and standby tariffs interact,
(4) Remove the line-loss study from Att. 6 and recognize that utilities already maintain this information for their territories,
(5) Revise Att. 6 to specify that the avoided capacity "look back" period is based on the useful life of the DG technology instead of 5 years,
(6) Revise Att. 6 to specify that the contract term length is based on the useful life of the DG resource instead of negotiated.

Minnesota Rural Electric Association

MREA highlighted that Minn. Stat. §216B.1611, Subd. 3 requires public utilities to adopt tariffs "consistent with" the Commission's 2004 Order, while municipal and cooperative utilities must adopt DG tariffs "that address the issues" in the Order.[11] MREA then recommends that accordingly, any such revisions to Att. 6 "should remain generic and make clear that cooperatives and municipal utilities need only address the issues outlined in the guidelines…"[12] MREA did not find that any revisions to Att. 6 are necessary at this time.

DISCUSSION

I. Legal Questions Identified by Parties

A. Is the Commission Required to Address Legal Questions Prior to Revising Attachment 6.

The Department recommends the Commission first resolve certain legal questions that

[10] Joint Comments by MNSEIA, ELPC, Fresh Energy, and Vote Solar, filed October 30, 2020.

[11] MNRE Comments, October 30, 2020, at 1.

[12] *Id*, at 2.

stakeholders have highlighted surrounding the applicability of Minnesota Stats. §§ 216B.1611 and 216B.164 and conflicts between Att. 6 and state and federal law before determining the details of an Att. 6 revision.[13] Minnesota Power supports the Department's recommendation to narrow the scope of inquiry and address legal questions regarding potential conflicts first.

Staff believes that the Commission has the option to consider the following legal questions prior to making changes to Attachment 6:

1. Whether Att. 6 has an enabling statute, and if so whether that statute is Minn. Stat. §216B.164, Subd. 4 or Minn. Stat. §216B.1611; and
2. Whether Att. 6. conflicts with state and federal law and rules such that certain changes are required to avoid preemption.

The Department then recommends the Commission address specific changes to Att. 6, with the main reasoning being to ensure that there is a sequential review of the final avoided cost methodology that is consistent with a shared understanding by all parties of the policy implications resulting from any changes to the pricing mechanism employed. This recommendation is also tied to the Department recommendation that the Commission consider timing these proceedings to benefit from information arising out of the deployment of Advanced Metering Infrastructure (AMI) meters and IEEE 1547-2018 compliant advanced inverters throughout their service territories in 2023.[14]

The Joint Commenters noted their appreciation for the Department's thoughtful comments but disagree with the Department's recommendation to first resolve legal questions surrounding applicability of statutes before determining Att. 6 revision, as they believe the record has been developed and supports Commission action to meaningfully implement Minn. Stat. §216B.1611.[15] This is discussed further in the next subsection.

There is nothing preventing the Commission from either (1) addressing the legal questions as described above, and then setting forth an additional notice of comment to streamline proposed edits to attachment 6 (**Decision Option 3, 6, 7**); or (2) addressing the legal questions and proposed changes (**Decision Option 3,5**).

B. Enabling Statute

A significant portion of this record is discussion devoted to the issue of an enabling statute.

Minnesota Power and Xcel Energy argued that Att. 6 is inconsistent with existing statute and rules in multiple areas, including the methodology used in determining avoided costs. Xcel

[13] Department Reply Comments, May 20, 2021, at 4.

[14] Department Comments, September 28, 2022, at 4.

[15] Joint Commenter Reply Comments, October 18, 2022, at 2.

indicated these areas within Att. 6 conflict with existing law, but Xcel does not expressly request a finding on enabling statute. In some cases, Xcel proposes changes that would resolve the alleged conflict, while in others they identify a conflict but do not propose a solution (see Section II).

Specifically, Xcel argued that Minnesota's implementation of Section 210 of PURPA (Minn. Stat. §216B.164) controls or limits how the Commission can implement the requirements of Minn. Stat. §216B.1611 and that conflicts arise between Att. 6 and Minn. Stat. §216B.164.[16] For example, Xcel appears to restrict the rates available to potential renewable DG projects between 1 to 10 MW by limiting the rate for those renewable projects to Xcel's least cost renewable resource- this essentially gives customer pricing from Minn. Stat. §216B.164, Subd. 4(b) instead of a tariff rate under §216B.1611.[17] Xcel also argued that under FERC's new PURPA rules, small power production facilities with a net power production capacity over 5 MW "will be presumed to have nondiscriminatory access to markets" and therefore Att. 6 should be limited to DER below 5 MW instead of 10 MW.[18] The full list of potential Att. 6 inconsistencies is discussed in Section II. In their April 30, 2021, comments, Minnesota Power stated they agree with Xcel and that more recent clarifications issued by FERC (Order 872-A) on its original update to PURPA rules did not appear to change any of Xcel's conclusions.[19]

Conversely, the Joint Commenters stated that the Minnesota DG Tariff[20] is a standalone program authorized by Minnesota law and thus not governed or preempted by PURPA or related FERC regulations. They additionally argued that Minnesota's PURPA implementation via Minn. Stat. §216B.164 does not control Att. 6 or DG Tariffs enacted under the auspices of §216B.1611. They also asserted that the DG Tariff and PURPA are created by completely different statutes (Minn. Stat. §§ 216B.1611 and 216B.164), and that the PURPA statute makes no reference to Minnesota's DG Tariff statute, which is a product of state law and makes no reference to PURPA.

The Joint Commenters further argued that while there are similarities between an avoided cost market stemming from PURPA and a potential distributed generation tariff market that arises from Att. 6, they are different. PURPA is a federal construct implemented by state statute, and any DG Tariff developed in accordance with Att. 6 is a separate state program created solely by state law. They believe compliance with both PURPA and the DG Tariff is possible, and as such

[16] Xcel Comments, October 30, 2020, at p. 3.

[17] Xcel Compliance filing, July 17, 2019, Attachment A at 3. See also October 30, 2020, Comments, at 3-4.

[18] Xcel Comments, October 30, 2020, at 4.

[19] Minnesota Power Comments, April 30, 2021, at 4.

[20] Staff understands the Joint Commenters' usage of "Minnesota DG Tariff" to mean any utility tariff developed specifically in accordance with the Att. 6 guidelines and §216B.1611, such as Xcel's 10-76, not all DG tariffs.

there is no issue of federal preemption of state law here.[21] The Joint Commenters' position is summarized in their October 30, 2020 Comments:

> 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.[22]

The Joint Commenters stated that "the utilities' unwillingness to focus on the guiding statute (§216B.1611) is causing the commenters to talk past each other and has confused and strained the record." [23] They also stated that Xcel's comments regarding PURPA, FERC or Minn. Stat. § 216B.164 "are misplaced in a conversation around Attachment 6" and "a red herring instead of helpful commentary on how to revise Attachment 6 to be usable or technically sound."[24]

MCA and HiP agreed with the Joint Commenters on the enabling statute, though they do not appear to explicitly ask for the Commission to decide on the issue.

In their May 20, 2021, reply comments, Xcel contested that Minn. Stat. §216B.164 is "invalidated" by PURPA and stated that on the contrary, "this statute implemented PURPA."[25] Xcel highlighted that the Minnesota Court of Appeals stated, "PURPA was codified in Minnesota under Minn. Stat. §216B.164, which enables the PUC to regulate the energy industry and implement PURPA's provisions."[26] Xcel stated that Minn. Stat. §216B.1611 governs interconnection standards and does not address the compensation rate applicable to DERs.

Staff Analysis

While it is unclear whether the Commission must make a finding about the proper enabling

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[21] Joint Commenter Comments, May 20, 2021, at 4-6.

[22] Joint Commenter Comments, October 30, 2020, at 4.

[23] Joint Commenter Reply Comments, October 18, 2022, at 2.

[24] Joint Commenter Reply Comments, May 20, 2021, at 6.

[25] Xcel Reply Comments, May 20, 2021, at 5.

[26] *In the Matter of the Petition of Northern States Power for Approval of Its Proposed Community Solar Garden Program*, (Minn. Ct. Appeals) No. A15-1831, 2016 WL 3043122, May 31, 2016.

statute, Staff believes it may be helpful to clarify whether Att. 6 relies on the utility's PURPA purchase obligation, or whether Att. 6 operates outside of PURPA, relying on independent state law. This determination may impact whether Att. 6 is subject to a potential PURPA preemption challenge and also affects whether the Commission believes that inconsistencies between Att. 6 and PURPA must be reconciled.

Thus, to move this docket forward, it is important to determine whether §216B.164 or relevant FERC orders limit or control the implementation of Att. 6. Staff agrees with Joint Commenters that Minn. Stat. §216B.1611 contains no references to §216B.164. However, Staff also notes that §216B.1611 does not address the compensation rate appliable to DERs, instead focusing on interconnection standards. Given the statute's silence, it may make sense to look to other relevant statutes that explicitly address rates for DERs, such as §216B.164.

If the Commission is inclined to align Att. 6 with PURPA and §216B.164, it may wish to look at each alleged conflict individually (see Section II, below). However, Staff notes that Att. 6 is a set of guidelines, and as such there may be inconsistencies between the guidelines and statutes/rules that do not necessarily require resolution. When reviewing tariffs, the Commission considers all relevant statutes, rules, and orders, and there may be cases where these dictate necessary exceptions to the guidelines.

If the Commission supports the Joint Commenter's argument that PURPA does not have any control over how Minn. Stat. §216B.1611 is implemented, then it may wish to disregard the changes requested by Xcel to align with current federal and state laws (Section II), because the Joint Commenters generally oppose all of Xcel's proposed revisions as they are based on the premise that the statute and Att. 6 is limited by PURPA. The Commission would still need to make determinations regarding other proposed revisions in Section III outside of the debate over the enabling statute. The Commission may also provide clarification that it does not intend to limit implementation of DG tariffs based on the requirements of PURPA, as requested by the Joint Commenters. This may result in more meaningful discussion about updating Att. 6 if the Commission chooses to make findings on the extent to which Att. 6 does not comply with §216B.164 and relevant FERC orders.

The Commission can determine that §216B.1611 is the enabling statute for Att. 6 with **Decision Option 2**, identify legal conflicts between Att. 6 with existing rules and statute with **Decision Option 3** and initiate further record development on them with **Decision Option 6**, and/or address potential conflicts individually with **Decision Option 5**. Staff additionally proposes **Decision Option 4**, which would amend Att. 6 with language to reflect that it offers guidance under multiple state statutes and is to be applied consistent with PURPA and relevant state statutes when applicable.

II. Proposed Revisions to Att. 6 to align with Current Federal and State Laws

The laws and rules potentially conflicting with Att. 6 have been identified as Minnesota Stats. §216B.1611 and §216B.164, Minn. Rules pt. 7835, and recent FERC revisions to rules governing PURPA. In the context of the FERC rules, Xcel argued that rules already apply as a matter of state statute and the Commission might give consideration as to how it intends to implement these revised FERC rules – whether it be via changes to Att. 6, or some other method.

Xcel points to the following as areas of conflict between Att. 6 and Minn. Stat. §§ 216B.1611 and .164, and Minn. R. Ch. 7835:

(1) the size of resources to which Attachment 6 should apply;
(2) the costs and benefits that should be considered in setting rates;
(3) the methodology for calculating avoided energy and capacity costs;
(4) the terms relevant to standby service; and
(5) whether specific renewable avoided cost rates must be offered. [27]

Staff will address each area of potential conflict individually.

A. Size

Xcel made several arguments as to why, if Att. 6 is to be modified, there should be no purchase obligation for facilities greater than 5 MW.

First, Xcel asserted that Att. 6's application to QF DER up to 10 MW is not consistent with Minn. Stat. §216B.164, Subd. 2, when read in conjunction with FERC's revised § 292.309 stating that small power production facilities with a net power production capacity over 5 MW are to be presumed to have nondiscriminatory access to markets (e.g. MISO or SPP). Xcel argued that although this limitation does not automatically apply (to apply, a utility must file with FERC to terminate the mandatory purchase obligation above this level), were it to apply, as Xcel believes it should, where a QF has access to markets, a utility has no purchase obligation and therefore the guidelines in Att. 6 should not apply. Broadly, Minn. Stat. §216B.164, Subd. 2 states that FERC rules and PURPA apply to all Minnesota utilities. [28] Accordingly, Xcel proposes

[27] Xcel Comments, October 30, 2020, at p. 3.

[28] Minn. Stat. 216B.164 subd. 2 states the following: "(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 Regulations, title 18, part 292, as amended."

that Att. 6, when applied to Small Power Production Facilities, should be limited to DER below 5 MW where there is no mandatory purchase obligation above this level.[29] Xcel noted that on June 29, 2021, FERC terminated Xcel's mandatory purchase obligation for new contracts or obligations from small power production facilities with net capacity in excess of 5 MW and that regardless of whether Att. 6 is amended, this limitation would still apply.[30]

The Joint Commenters oppose Xcel's proposition to limit the capacity size of the DG Tariff to 5 MW, as they believe Xcel's proposition is based on its "flawed belief" that Minn. Stat. §216B.1611 is limited by PURPA. The Joint Commenters also asserted that Xcel's proposition conflicts with the plain language of Minnesota's requirement that utility tariffs have a capacity size of up to 10 MW, Minn. Stat. §216B.1611, Subd. 2.

Staff Analysis

Staff agrees with Xcel that they (and any utility with such an exemption from FERC) are not obligated to purchase from facilities with net capacity in excess of 5 MW even if the Commission elects not to make the change unless the facility can demonstrate it does not have access to the market as defined in FERC § 292.309(f)(2) or is eligible to participate in a rate offering enabled by Minn. Statute and/or utility tariff. Therefore, Staff finds it to be reasonable to amend Att. 6 to reflect this with **Decision Option 5A**.

B. Customer Costs that Should be Considered in Setting Rates

Xcel argued that the language of Minn. Stat. §216B.164, Subd. 8(b) requires consideration of additional costs caused by the DG including interconnection. The relevant subdivision states:

> 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 congenators or small power producers, or from any fixed charges normally assessed such non-generating customers.

The Joint Commenters did not respond to the issue specifically but have a global argument that Att. 6 is not in conflict with Minn. Stat. §216B.164 because it is a product of §216B.1611.

Staff Analysis

Staff does not see any component of Minn. Stat. §216B.1611 that excuses DG customers from the costs they impose on the system; in fact, MN DIP 5.6.5 and DIA 6.1.1 address interconnection costs being the responsibility of the customer. Therefore, even if the Commission believes that Att. 6 is not constrained by Minn. Stat. §216B.164, there does not

[29] Xcel Comments, October 30, 2020, at p. 5.

[30] Xcel Comments, September 28, 2022, at 2.

appear to be any reason why Att. 6 could not be amended to further reflect that utility tariffs should be cost causal and require customers to pay for their excess costs of interconnection and wheeling to the extent that they are not already.[31] Because Xcel did not provide any specific language to accomplish this request, Staff submitted **Decision Option 5B** to amend Att. 6 paragraph 6, on the calculation of avoided costs, with the language cited above from Minn. Stat. §216B.164, Subd. 8(b).

C. Avoided Cost

A major point of contention is the methodology for calculating avoided energy and capacity costs. Section 210 of PURPA requires electric utilities to purchase energy and capacity from QFs, with the rates for these purchases based on the utility's "avoided costs," or the incremental cost to the utility to either produce or procure energy itself instead of buying it. FERC Order 872 and 872-A updated FERC rules on avoided cost calculations.

Xcel argued that paragraphs 5 and 6 of Att. 6, which address setting rates and calculation of avoided costs, do not align with state statute and rule, but did not claim that there is a conflict here with FERC's revised PURPA rules and provided a short discussion of relevant PURPA rules. Xcel pointed to revised FERC rule 292.304(d), which gives QFs the option to either provide energy as available, with rates based on avoided costs, or provide energy or capacity pursuant to a Legally Enforceable Obligation (LEO) over a specified term. Revised FERC Rule 292.304(e)(1) sets forth methodological options of determining avoided costs by either establishing rates based on market price at the time of delivery, or energy and/or capacity rates based on a Competitive Solicitation Price. Xcel noted that if the Commission does not follow that methodology, then under 292.304(e)(2), it must follow the rules listed within that paragraph. Xcel believes that the avoided energy guidelines in Att. 6 are general enough not to conflict with these rules.[32] However, Xcel argued that Att. 6 guidelines on how to determine avoided capacity and energy costs differ from that set forth in Minn. R. 7835.4020, the rule of capacity payments that sets forth following:

> 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;

[31] Staff notes that Minn. Stat. 216B.2425; Subd. 8 and the Distributed Energy Resources System Upgrades Grant Program established by Law 2023, Ch. 60, Art. 11, Sec. 2; Subd 10 enable preemptive investments in the grid to reduce individual project's interconnection costs; and the Commission has approved shared interconnection costs programs (Docket Nos. 16-521 & 18-714): Xcel's Cost Sharing Fee for small DER customers and Cluster Studies.

[32] Xcel Comments, October 30, 2020, at 6.

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.

Xcel stated that Att. 6 only addresses issues set forth in pars. B and C of R. 7835.4020.

Xcel also argued that separate from above, Att. 6 differs from Minn. Stat. §216B.164, Subd. 4, which, as noted earlier, bases the full avoided capacity and energy costs on the lower of the utility's least cost renewable energy facility or the bid of a competing supplier of a least cost renewable energy facility.

The Joint Commenters strongly oppose both Xcel's rules and statute arguments because they believe the least cost renewable resource provision of §216B.164 and the negotiated rates from Minn. Rule 7835.4020 should not apply to Att. 6, as explained in Section I. In their October 18, 2022, reply comments, the Joint Commenters stated that the Commission is not bound by Minn. Stat. §216B.164, because it opted to implement an avoided cost methodology under Minn. Stat. §216B.1611.[33] Specifically, they asserted that the Commission chose to use an avoided cost methodology in 2004, when it could have used other rate making methodologies like proxies, competitive solicitations, etc. As such, while there are legislative instructions on calculating avoided cost in Minn. Stat. §216B.164, Subd. 4, as it pertains to Minnesota's implementation of PURPA, such a limitation does not appear in the controlling statute at issue here, Minn. Stat. §216B.1611. Further, the Joint Commenters cited the Commission Order in Docket No. 16-1021 regarding the Red Lake Falls wind/solar hybrid project (Red Lakes Fall Order) and asserted this demonstrates that "least-cost renewable energy language is not applicable to projects in Minnesota."[34] The Commission stated:

> 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(d), 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

[33] Joint Party Reply Comments, May 20, 2021, at p. 2

[34] Joint Party Comments, October 30, 2020, at 9.

> costs based on Otter Tail's 2017 Small Power Production Tariff filing of January 3, 2017.[35]

Therefore, the Joint Commenters asserted that rather than being constrained by Minn. Stat. § 216B.164, the Commission is actually authorized by the second sentence of subd. 4(b)[36] to set avoided cost rates for QFs, as it ruled in the Red Lake Falls Order. Xcel noted that the avoided cost PPA prices set for the Red Lake Falls hybrid project, which are based on the tariffed rates in the Otter Tail Power's Small Power Production tariff, differ from the Att. 6 provisions, and stated that their proposed pricing in the St. Cloud Hydro PPA is consistent with the Red Lake Falls Order and is broadly consistent with §216B.164, Subd. 4(b). [37]

The record also features numerous comparisons of the Att. 6 methodology to the Value of Solar (VOS) established in Minn. Stat. §216B.164, Subd. 10, the Department's VOS Methodology (Docket No. 14-65), and Xcel's Solar*Rewards Community Program, which the Joint Commenters argued was explicitly predicted on an avoided cost methodology but does not determine avoided cost pricing on competitive solicitations despite creating pricing for renewable energy.[38] Staff notes that VOS may mention "avoided costs," but is not inherently a part of Minn. Stat. §216B.164, Subd. 4, as the VOS is located in Subd. 10 which does not reference Subd. 4.

MCA and HiP agreed with the Joint Commenters that the methodology laid out in Att. 6 is the correct way to calculate avoided costs and recommend the Commission find that:

> To the extent that Xcel or any other Minnesota utility believes that it can apply a rate methodology from another statute to determine avoided costs for DG resources, Attachment 6 should expressly state that the methodology provided in Attachment 6 is the proper rate method for establishing avoided cost rates for DG.[39]

<u>Staff Analysis</u>
Minn. Stat. §216B.1611 does not offer guidance on how rates established under Att. 6 should

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[35] Commission Order, May 31, 2018, in Docket No. 16-1021, at 13.

[36] The second sentence states that "[t]he 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."

[37] Xcel Comments, October 30, 2020, at 6, and Reply Comments, May 20, 2021, at 8.

[38] Joint Party Comments, October 30, 2020, at p. 5, citing 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).

[39] MCA and HiP Comments, October 30, 2020, at 1.

be calculated.[40] At the time Att. 6 was developed, a DG Rate Work Group was convened that recommended the methodology. The regulated electric utilities did not oppose the formula for avoided cost and noted "that it basically conforms to the calculations used for their annual Cogeneration and Small Power Production filings."[41]

Minn. Stat. §216B.164, Subd. 4(b) does offer more explicit guidance and states:

> 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.

In its Red Lake Falls Order, the Commission interpreted the phrase "as set by the commission" to grant it discretion in setting avoided costs that may differ from the least-cost renewable approach described in the following sentence.[42] More, under revised §292.304(e)(2), FERC also grants the State regulatory authority the ability to substitute an alternative method contingent upon the methodology accounting for the following:

> (i) The data provided pursuant to § 292.302(b), (c), or (d), including State review of any such data;[43]

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[40] Under subdivision 2, it states that tariff standards must comply with the following: (1) To the extent possible, be consistent with industry and other federal and state operational and safety standards; (2) provide for the low-cost, safe, and standardized interconnection of facilities; (3) take into account differing system requirements and hardware, as well as the overall demand load requirements of individual utilities; (4) allow 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; and (5) establish (i) a standard interconnection agreement that sets forth the contractual conditions under which a company and a customer agree that one or more facilities may be interconnected with the company's utility system, and (ii) a standard application for interconnection and parallel operation with the utility system.

[41] Commission Order, September 28, 2004, at 11.

[42] Commission Order, May 31, 2018, at 12.

[43] § 292.302 governs the availability of avoided cost data. Part (d) grants the State regulatory authority the ability to require alternative data if "it determines that avoided costs can be derived from such data."

(ii) The availability of capacity or energy from a qualifying facility during the system daily and seasonal peak periods, including:

(A) The ability of the electric utility to dispatch the qualifying facility;

(B) The expected or demonstrated reliability of the qualifying facility;

(C) The terms of any contract or other legally enforceable obligation, including the duration of the obligation, termination notice requirement and sanctions for non-compliance;

(D) The extent to which scheduled outages of the qualifying facility can be usefully coordinated with scheduled outages of the electric utility's facilities;

(E) The usefulness of energy and capacity supplied from a qualifying facility during system emergencies, including its ability to separate its load from its generation;

(F) The individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system; and

(G) The smaller capacity increments and the shorter lead times available with additions of capacity from qualifying facilities; and

(iii) The relationship of the availability of energy or capacity from the qualifying facility as derived in paragraph (e)(2)(ii) of this section, to the ability of the electric utility to avoid costs, including the deferral of capacity additions and the reduction of fossil fuel use; and

(iv) The costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from a qualifying facility, if the purchasing electric utility generated an equivalent amount of energy itself or purchased an equivalent amount of electric energy or capacity.

As noted previously, Xcel stated it is their "understanding that the avoided energy Guidelines in Attachment 6 are general enough to not conflict with the longstanding FERC rules" (listed above). However, Xcel argued further that there is a separate conflict with Minn. Rules 7835.4020, which the Joint Commenters contended is unrelated. Staff agrees that there appears to be an inconsistency here, as Att. 6 and Minn. Rules 7835 govern overlapping spaces yet apply different considerations for calculating capacity payments. For example, Minn. Rules 7835.4020 requires consideration of "the willingness and ability of the qualifying facility to provide firm power during system emergencies" yet Att. 6 has no similar component in its methodology. [44] Att. 6 was approved in 2004 and considered Minn. R. Ch. 7835 at that time; Minn. Rule 7835.4020 was part of a later update to Minn. R. Ch. 7835 in 2015.

That said, Att. 6 is a set of guidelines, which makes it less clear to Staff whether an alleged conflict between the attachment and the rules must be resolved in this case.[45] The Commission reviews utility tariffs and considers all relevant statutes, rules, and orders. In the annual update of public utility's small power production avoided cost standard rates (Docket No. YR-9), Staff reviews the proposed rates compared to Minn. R. Ch. 7835 and sees the more detailed provisions of the rules as consistent with the components of avoided capacity cost in Att. 6 paragraph 6, though not the actual formula in the attachment. In other words, the tariffed standard offer rates reasonably comply with the purpose of the guidelines.

Regarding the proposed language from MCA and HiP to specify that all DG tariffs must adhere to the rate calculation in Att. 6, Staff posits that this may change the interpretation of it as a set of guidelines, and the language does not recognize that some DG tariffs may be governed by specific statutes or rules with requirements outside of Att. 6.

Based on the Commission's interpretation of Minn. Stat. §216B.164, Subd. 4 in the Red Lake Falls Order, Staff finds that there is not a conflict between the statutes and Att. 6 in regard to the rate determination. Both in statute and in PURPA, the Commission is granted the authority to set an avoided cost rate that may differ from the least-cost renewable resource. However, because Minn. Stat. §216B.1611 does not specify a methodology, the Commission could amend Att. 6 to use the least-cost renewable approach from Minn. Stat. §216B.164 if the Commission perceives there to be a conflict or if the Commission reasons this approach is superior (**Decision Option 5C)**.[46] Regardless of its decision on amending the rate, the Commission could adopt the proposed language from MCA and HiP to require utilities to use the Att. 6 methodology in designing DG tariffs instead of any alternative approach (**Decision Option 8)**. The Commission can also identify a conflict between Att. 6 and Minn. Rules 7835.4020 with **Decision Option 3B**

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[44] Minn. Rules 7835.4020 states that the amount of capacity payments must be determined through consideration of: the capacity factor of the qualifying facility; the cost of the utility's avoidable capacity; the length of the contract term; reasonable scheduling of maintenance; the willingness and ability of the qualifying facility to provide firm power during system emergencies; the willingness and ability of the qualifying facility to allow the utility to dispatch its generated energy; the willingness and ability of the qualifying facility to provide firm capacity during system peaks; the sanctions for noncompliance with any contract term; and the smaller capacity increments and the shorter lead times available when capacity is added from qualifying facilities.

[45] For example, the Order states, "After the Commission adopts these guidelines, each utility will file its distributed generation tariffs; the resulting docket will provide the appropriate forum for evaluating the extent to which the tariff adequately fulfills the purposes of these guidelines." 2004 Order at 12.

[46] Staff notes that because Xcel did not actually make an explicit recommendation, Decision Option 3C is based on what Xcel appears to be offering QFs- the least-cost renewable resource methodology.

and request further record development on resolution with **Decision Option 6**. The Commission could take no action as well if it finds there is no conflict or issue regarding avoided cost in Att. 6 that requires an amendment.

D. Standby Service

Xcel argued that paragraphs 7.b. and 7.e of Att. 6, which address standby rates, apply a different size exemption than Minn. Stat. §216B.164, Subd. 2(a) and 3(a), which provide directions for the standby provisions to be provided for in a utility's tariff.[47] Att. 6 exempts DER facilities of 60 kW or less from standby service, while the standby tariff (consistent with current state statute) exempts systems of 100 kW or less.

The Joint Commenters did not respond to this issue specifically but have a global argument that Att. 6 is not in conflict with Minn. Stat. §216B.164 because it is a product of §216B.1611. The Joint Commenters do propose, however, language whereby a DG facility that determines it will not need standby service is exempted from paying any standby charges regardless of size.[48]

Staff Analysis

Staff agrees with Xcel that there is an inconsistency here between Minn. Stat. §216B.164 and both Att. 6 and Minn. R. 78525.2600, which was last updated in 2015 and also specifies 100 kW or less. Since §216B.1611 does not offer any guidance on standby service, there appears to be no barrier to amending Att. 6 to reconcile the size exemption with statute (**Decision Option 5D).** Staff addresses the Joint Commenters' proposal in Section III.H.

E. Offering of Specific Renewable Avoided Cost Rates

Xcel argued that paragraphs 4 and 8 of Att. 6, which both address renewable credits, do not align with Minn. R. 7835.5950 and the recent FERC order, although the state rule complies with the FERC Order. Par 8(e) requires DG customers to "be paid the avoided cost of 'green power' to the extent that installation of the DG facility allows the utility to avoid the need to purchase 'green power' elsewhere. Otherwise, a renewable DG facility should be paid the utility's regular avoided costs."

Minn. R. 7835.5950 states:

> 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

[47] Xcel Comments October 30, 2020, at 4.

[48] Joint Commenters Tracked Changes to Att. 6, October 30, 2020, at 5.

FERC Order 872 paragraphs 123 and 176 note that non-energy benefits are not part of PURPA avoided costs. Xcel argued that the FERC order states that there is no avoided cost for green power, and thus Att. 6 cannot require payment of the avoided cost for green power.[49]

The Joint Commenters did not address this point specifically but did propose revisions to the same section of Att. 6, as discussed at Section III.G.

<u>Staff Analysis</u>
The language from the FERC order states that "nothing in PURPA, the PURPA Regulations as they currently exist, or this final rule would prevent states from rewarding QFs for such non-energy benefits so long as that is done outside of PURPA, such as is now done for renewable energy credits (RECs) to compensate QFs for providing unique environmental or other non-PURPA benefits."[50] Thus, this may not be wholly in conflict, and there may be room for state actors to require DG customers to be paid the avoided cost of green power. For instance, Otter Tail Power offers compensation in the Company's tariff for solar RECs to comply with Minnesota's solar energy standard (Docket No. 16-280); whereas, Minnesota Power and Xcel have used CSG and solar incentive programs to procure the solar RECs. Staff notes that Xcel did not propose a specific recommendation. **Decision Option 3B** would identify a conflict with Minn. Rules 7835, and the Commission could solicit further record development with **Decision Option 6**. Staff **Decision Option 4** would add language to Att. 6 to reflect that PURPA is one but not the only factor in DG rate setting in Minnesota, and that DG rate guidance also factors in state statutes and associated rules.

III. <u>Further Revision to Att. 6</u>

Commenters request several changes that are unrelated to potential conflicts with state statute. The Commission can consider the following proposals regardless of what decisions are made regarding Section I and II. Staff has included the Joint Commenters' redline edits of Att. 6 as Attachment B.

The Department stated that the Commission may wish to first determine potential conflicts with statute and then develop the record before deciding on other revisions discussed below (**Decision Option 7**).[51] Given that there have been two rounds of comment periods and multiple years of record development, Staff believes that the Commission may still be able to make determinations regarding many of the following without further development and notes that stakeholders had ample opportunity to respond to these suggestions.

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[49] Xcel Comments, October 30, 2020, at 6-8.

[50] FERC Order 872 paragraph 123

[51] Department Reply Comments, May 20, 2021, at 4.

A. Line Loss Credits

Att. 6 specifies that for a DG customer to receive line loss credits above those already included in the avoided cost calculations[52], the DG customer must request and pay for the utility to conduct a specific line loss study to determine whether additional credits are warranted.[53] The Joint Commenters stated that in most cases the cost of the study would outweigh the benefits and request an alternative method based on an approach used in Michigan.[54] They propose that a line loss credit be applied to the avoided energy cost rate by multiplying it by the utility's system wide line loss factor plus 1, as shown in the following calculation:

$$A2= (1+a)*A1$$

where A1 is the avoided energy cost rate, a is the system wide line loss factor expressed as a percent, and A2 is the avoided energy cost rate modified by line loss factor.

MCA and HiP agree that as it stands the cost of the study would generally outweigh the benefits to a customer and request that the line loss methodology be amended to be calculated from existing utility data instead of a line-loss study.[55]

In their reply comments, Xcel stated that they are not aware of requests for specific line loss studies and noted that their system-wide line loss values are publicly available in their annual QF filing in the Year-09 docket.[56]

Staff Analysis

Staff agrees with the Joint Commenters and MCA/HiP that requiring a specific line loss study is cumbersome and that the cost likely denies credits that would otherwise be given to a DG customer. Staff also notes that Xcel is not actually opposing it in their reply comments. Using existing information for utilities, as MCA and HiP have suggested, may be slightly simpler, but the Joint Commenters' recommendation would ensure that the methodology is consistent across utilities. The Commission can implement the Joint Commenters' recommendation with **Decision Option 9** or MCA/HiP's recommendation with **Decision Option 10**.

B. Capacity Cost Calculations

For the calculation of avoided capacity costs, Att. 6 states that the need for capacity is

[52] Staff does not see that line losses are presently included in the avoided cost calculations, despite the language here, which is an observation also made by the Joint Commenters.

[53] Att. 6 paragraph 8.d

[54] Joint Commenter Comments, October 30, 2020, at 12 and Tracked Changes at 6.

[55] MCA and HiP Comments, October 30, 2020, at 4.

[56] Xcel Reply Comments, May 21, 2020, at 10.

established by the utility's most recent IRP and that "a need exists if the utility shows a deficit at any year of the 5-year planning period."[57] The Joint Commenters request that capacity cost calculations be aligned with 15, not 5-year periods, so as to align avoided capacity costs with integrated resource planning. The Joint Commenters argued that the 5-year period is misaligned with the useful life of most DG assets, such as solar farms that typically have a 25-year project life, and thus recommend a 15 year look ahead with the remaining years of the contract using annualized capacity values.[58]

MCA and HiP agreed that the 5-year period is too short and recommend Att. 6 be revised to specify that the avoided capacity period must "reflect the useful life of the DG technology."[59] MCA and HiP noted that cogeneration systems are often estimated to have useful lives of 15-20 years but that many MCA members have systems installed in the 1980s that are operating 40+ years later.

In their reply comments, Xcel highlighted that the Commission addressed this in the 2004 Order, which stated: "[t]he Commission concludes the value that ratepayers receive from having reserve capacity 15 years before any anticipated need is too slight to warrant compensation."[60] Xcel further noted that the IRP has a 5-year action planning period as required by state rule.[61]

<u>Staff Analysis</u>
As Xcel noted, the Commission considered this issue when originally developing Att. 6, and it is highlighted as the "largest dispute" from the Work Group's report.[62] The rate regulated utilities originally objected to paying for any DG capacity before a demonstrated need exists and noted the general rule against requiring ratepayers to pay for plants that had not been proven "used and useful."[63] The Clean Water Action Alliance, the DG Coalition, the Green Institute, North American Water Office, and Windustry contended that this would discriminate against non-utility generators because utilities pay for all costs of a new plant years before its capacity is

[57] Att. 6 paragraph 6.b

[58] Joint Commenters Comments, October 30, 2020, at 12-13 and Tracked Changes at 3.

[59] MCA and HiP Comments, October 30, 2020, at 4.

[60] Xcel Reply Comments, May 21, 2020, at 10-11, citing Commission Order, September 28, 2004, at 15.

[61] MN State Rule 7843.0400 Subp 3C states "The supporting information must include an action plan, a description of the activities the utility intends to undertake to develop or obtain noncurrent resources identified in its proposed plan. The action plan must cover a five-year period beginning with the filing date. The action plan must include a schedule of key activities, including construction and regulatory filings."

[62] Commission Order, September 28, 2004, at 14.

[63] *Id*

needed and therefore DG resources should receive the same treatment. As such, the Department and DG coalition recommended using 15-year periods. The utilities then conceded that there are benefits to having additional DG capacity on hand before need is anticipated but argued that “a policy of paying 15 years in advance violates that principle that each generation of ratepayers should pay for the plant that benefits itself, not for [the] plant that will only benefit future ratepayers.”[64] The utilities also argued that 15-year forecasts are too variable to justify commitments of this nature and proposed 5-year periods as a compromise, which persuaded the Commission.

Staff finds that the arguments now are the same as then, though that need not preclude the Commission from changing course. For comparison, Minn. R. 7835.0600 (Schedule B) looks at all planned capacity additions during the next 10 years and the standard offer capacity rate (Docket No. YR-9) uses the nearest-term planned addition to establish the annual avoided capacity cost. The Commission can adopt the Joint Commenters’ proposal with **Decision Option 11** or MCA/HiP’s recommendation with **Decision Option 12**.

C. Contract Terms

Att. 6 currently contains no requirements for contract terms. The Joint Commenters request that contract terms be adjusted “to encourage financeability and fairness,” which they claim the guidelines presently do not do because each utility’s DG Tariff calls for either an individual PPA with varying negotiated terms or is reset each year. [65] The Joint Commenters recommend Att. 6 be amended to include a term-length requirement that requires utilities to offer contract terms up to 25 years with fixed rates.

MCA and HiP stated that negotiated contracts are expensive and unnecessary for small DG projects and recommend that Att. 6 be amended to state that “contract length should reflect the useful life of the DG system.”[66]

In response, Xcel highlighted that their DG tariff sheets contain a variety of term lengths and stated that for merchant plants over 1 MW who are QFs, they generally receive requests for a PPA for a longer-term contract. In these cases, Xcel follows the requirements from PURPA and Minn. Stat. §216B.164 for avoided cost pricing.[67]

Staff Analysis

The existence of other, related tariffs with varying term lengths is not an argument against

[64] *Id*

[65] Joint Commenter Comments, October 30, 2020, at 14 and Tracked Changes at 4.

[66] MCA and HiP Comments, October 30, 2020, at 4.

[67] Xcel Reply Comments, May 20, 2021, at 6 and 11.

doing the same with tariffs developed in accordance with Att. 6. Staff agrees with MCA/HiP that requiring contracts be negotiated annually is cumbersome and expensive for small DG customers. Staff notes on-site DG up to 1 MW is eligible for a standard offer rate under Minn. Stat. 216B.164 and Minn. R. Ch. 7835 with utilities updating the rate annually (Docket No. YR-9) and CSG in Xcel's service territory are offered 25-year contracts. FERC declined to adopt a minimum contract length for PURPA noting "it is up to states to decide appropriate contract lengths in a way that accurately calculates avoided costs so as to meet all statutory requirements."[68] The Commission can adopt the Joint Commenters' recommendation for 25-year contracts with **Decision Option 13** and MCA/HiP's recommendation for term lengths based on the life of the resource with **Decision Option 14**.

D. <u>Onsite Requirement</u>

Att. 6 requires the DG facility to be an operable, permanently installed, or mobile generation facility serving the customer receiving retail electric service at the same site. The Joint Commenters stated that the onsite requirement in Att. 6 is "archaic" and unnecessary and recommend it be removed.[69] The Joint Commenters stated that the Commission "implicitly agreed" with this when it updated the state interconnection standards in the docket, which are closely related to Att. 6 through §216B.1611, Subd. 2 and 3, to no longer require onsite load. The Joint Commenters further asserted that "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."[70]

Minn. Stat. §216B.1611, Subd. 1 states that the purpose of this statute is to "establish the terms and conditions that govern the interconnection and parallel operation of on-site distributed generation." The Joint Commenters argued that the statutory requirement can be met with the "concept of 'house power,' or the need to pull a minor amount of retail electric service for a DG Facility to operate continuously." They concluded that "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.'"[71]

The City of Minneapolis stated that co-siting generation and load may be preferable in many situations but that the City wishes to "optimize solar siting for higher production and lower project costs" in order to meet renewable energy goals.[72]

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[68] FERC Order 872, at 360, p. 206

[69] Joint Commenters Comments, October 30, 2020, at 15.

[70] *Id.*

[71] Joint Commenters Comments, October 30, 2020, at 15.

[72] City of Minneapolis Comments, September 28, 2022, at 2.

Staff Analysis

While the statutory language about the onsite requirement is straightforward, Staff agrees with the Joint Commenters that the house power concept could possibly be used to meet this and align Att. 6 with MN DIP, which allows for stand-alone generation and also must meet the requirements of §216B.1611.[73] The MN DIP/DIA are primarily statewide interconnection standards and recognize that Minnesota has a variety of DG/DER seeking to interconnect and operate in parallel with the utility distribution grid ranging from on-site, net-metered projects to CSG or PPA projects. Regarding rates offered to these various projects, the Commission looks to several statutes for guidance; including, but not limited to, PURPA. The Commission can amend Att. 6 to expand the rate guidance to off-site generation with **Decision Option 15.**

E. Diversity and Reliability Credits

Att. 6 states that "no additional diversity credits for energy and capacity should be given to DG customers who contract for standby service."[74] The Joint Commenters highlighted that the Order and Att. 6 do not discuss whether Diversity Credits should be permitted for non-standby systems and asserted that the omission in fact "suggests that Diversity Credits should be applied."[75] They noted that no utility currently includes them in their DG tariffs and ask that Att. 6 be revised to specify that Diversity and Reliability Credits should be given to customers not on standby service.

In their reply comments, Xcel stated that diversity credits are not applied to DG tariffs because these resources are not used by MISO to establish the planning reserve margin requirement.[76]

Staff Analysis

The 2004 Order explains that the Commission opted not to apply diversity credits because to the extent a small generator benefits system reliability, it is offset when the customer contracts for standby service, as was contended by the utilities at the time. The utilities further argued that planning reserve margin requirements are only based on the consideration of large generators.[77] The Order provides no additional guidance on whether diversity credits should apply to non-standby systems, and Staff is unconvinced the omission should be interpreted as the Joint Commenters have done.

The Commission can choose to apply Diversity Credits to DG customers who do not contract for

[73] The Pre-Application report at 1.4.1.7 asks whether the customer is a stand-alone generator, defined as "no onsite load, not including station service."

[74] Att. 6 paragraph 8.e

[75] Joint Commenters Comments, October 30, 2020, at 16.

[76] Xcel Reply Comments, May 20, 2021, at 11-12.

[77] Commission Order, September 28, 2004, at 24-25.

standby service with **Decision Option 16**.

F. Distribution Credits

Att. 6 currently provides that distribution credits to DG customers should equal the utility's avoided distribution costs resulting from the installation facility, but screening studies to determine if a DG project has the potential to receive distribution credits based on the utility's list of substation areas or feeds are required.[78] These studies are at the customer's expense, and the Joint Commenters stated that this approach not only does not provide transparency in terms of who is eligible for receiving distribution credits but also "likely underestimates the avoided distribution costs associated with DG projects by focusing on the utility's distribution planning process […] to the exclusion of avoided costs over the lifetime of a DG project."[79] The Joint Commenters recommend that the DG Tariff should include distribution credits accounting for short- and long-run avoided distribution costs.[80] The Joint Commenters explained that the long-run value would capture the "counterfactual estimate of what it would have cost to add system capacity in the absence of DER" while the short-run value would capture locational avoided capacity costs.[81]

Staff Analysis

While the Joint Commenters referenced a methodological approach used in California, their redline edits do not actually contain any revisions to this section of Att. 6 or specify what the methodology would look like. In their October 30, 2020, comments, they propose that a framework for calculating avoided distribution system capacity proposed by Professor Chan in a May 5, 2020, letter in Docket. No. 13-867 could be a suitable approach for determining the short-run value if this framework was adopted by the Commission for the VOS methodology, but it was not adopted.[82] This methodological approach was not referenced in the Joint Commenters' September 28, 2022, comments on this issue. As such, in the absence of a clear recommendation, Staff's only Decision Option for this issue is to pursue further record development (**Decision Option 17**).

G. Technology-specific Avoided Costs and RECs

As noted earlier, Att. 6 currently states that renewable DG customers "should be paid the avoided cost of 'green power' to the extent that installation of the DG facility allows the utility to avoid the need to purchase 'green power' elsewhere" and that otherwise the facility should

[78] Att. 6 paragraph 8.b

[79] Joint Commenters Comments, October 30, 2020, at 17.

[80] Joint Commenters Comments, October 30, 2020, at 17.

[81] *Id*

[82] Commission *Order Approving Xcel's 2021 Value-of-Solar Rate,* March 9, 2021.

receive the utility's regular avoided costs.[83]

The Joint Commenters propose that if the Commission would like to apply technology-specific avoided costs, then it could:

> 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.[84]

As such, the Joint Commenters propose a change which would clarify that DG facilities retain their RECs under the regular avoided cost rate but allows the utility to obtain the RECs under technology-specific renewable avoided cost rates, since this "green power" rate includes compensation to the DG facility for the RECs it generates.[85]

As discussed in Section II.E, Xcel argued that under PURPA, the utility cannot be required to pay for the avoided cost of green power as part of the avoided cost rate. Xcel also noted that the Commission has already authorized technology-specific avoided cost pricing.[86]

Staff Analysis

Regarding technology specific generation, the Joint Commenters' proposal aims to resolve ambiguity in what the rate would be for the avoided cost of green power as described in Att. 6. In their tracked changes, the Joint Commenters propose defining "green power" as "the specific renewable technology that the utility would otherwise need to build or purchase" and recommend clarifying that the rate should be based on these technology-specific avoided costs.

Regarding the RECs proposal, if the Commission determines that RECs cannot be part of the avoided cost rate based on PURPA, then the Joint Commenters proposal would need to be modified to reflect this. The FERC revisions do grant authority to award non-energy benefits as part of compensation outside of the avoided cost rate (see Section II.E).

The Commission can adopt the Joint Commenters' proposal to value different generation profiles with **Decision Option 18** and the RECs proposal with **Decision Option 19**.

[83] Att. 6 paragraph 8.e

[84] Joint Commenter Comments, October 30, 2020, at 18-19.

[85] *Id*

[86] Xcel Reply Comments, May 20, 2021, at 12.

H. Standby Charges

As mentioned previously, Att. 6 paragraph 7.e specifies that QFs of 60 kW or less are exempt from paying standby charges. The Joint Commenters stated that it is "discriminatory and unfair to allow a utility to charge a DG facility- regardless of size- for standby service if the DG facility has reasonably determined that it will not need standby service." The Joint Commenters propose that Att. 6 be amended to reflect that any DG facility that determines it does not require standby service does not need to pay standby charges.

MCA and HiP request clarification from the Commission on how Att. 6 interacts with standby tariffs. Specifically, they stated one problem is that customers taking back-up and maintenance service under a standby tariff are not eligible for energy or capacity credits. They argued there "is no valid rationale for excluding cogeneration DG facilities that are required by law to take back-up and maintenance service from a utility – which is almost all cogeneration DG in the state- from the energy and capacity credits offered to other DG" under Att. 6.[87]

In their reply comments, Xcel addressed MCA and HiP's concerns regarding the terms of standby service. Xcel argued that this discussion is misplaced here and that the standby rider design accounts for differences in the availability of a customer's generation. Additionally, Xcel noted that cogeneration systems are compensated via lower tariff charges for their capacity and energy contributions.[88]

Additionally, Xcel proposed that the exemption be amended to 100 kW or less, as discussed in Section II.D.

Staff Analysis

Minn. Stat. §216B.164, Subd. 3(b)(2) states that a public utility can only impose a standby charge on a QF of more than 100 kilowatts in "accordance with an order of the commission establishing the allowable costs to be recovered through standby charges." Minn. Stat. §216B.1611 offers no guidance on standby charges. Staff then believes that the Commission could adopt this change without creating conflict with statute and reasons that if a QF can demonstrate that standby service is not necessary, then it would be cost causal for the tariff to provide them an exemption (**Decision Option 20**).

Staff agrees with Xcel that the MCA/HiP's discussion is out of scope in the current proceeding and that the terms of standby service were already addressed in Docket No. CI-15-115.

[87] MCA and HIP Comments, October 30, 2020, at 4.

[88] Xcel Reply Comments, May 20, 2021, at 14.

IV. Transparency and Access to Rate Information

The Joint Commenters, MCA, and HiP argued that there is a lack of transparency regarding rate calculations that makes it impossible for parties to determine whether the avoided cost credits are fair, which Xcel, Otter Tail Power, and Minnesota Power all contest. The Commission took this issue up recently in Docket No. 19-9 with robust record development and issued its February 21, 2020, Order in Docket No. 19-9, denied reconsideration in its May 7, 2020, Order. A DG project developer/customer can attain a non-disclosure agreement with the utility to access trade secret details.

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DECISION OPTIONS

Conflicts with Existing Statutes and Rules

1. Find that there is no present conflict of Att. 6 with current federal and state law and make no changes to Att. 6. (*MREA*)

OR

2. Determine that the enabling statute for Att. 6 is Minnesota Stat. §216B. (*Joint Commenters*)

OR

3. Find that the following are areas where federal rules and statutes conflict with existing Att. 6 requirements:
   A. Minnesota Statutes §216B.1611 and §216B.164;
   B. Minn. Rules Ch. 7835; and
   C. Recent FERC revisions to rules governing PURPA. (*Xcel, Minnesota Power*)

AND

4. Amend Att. 6 to include the following: The Commission recognizes Att. 6 offers guidance for distributed energy resource rates under multiple state statutes (e.g. Minn. Stat. 216B.1611, .164, .1641, .1691) and, when applicable, is to be applied consistent with PURPA. Rate-regulated utilities' tariffed rates are reviewed by the Commission consistent with all relevant state and federal statutes, rules, and orders. (*Staff*)

Following a Determination of Conflicts (i.e., if Decision Option 3 is taken)

5. Amend Att. 6 as follows**:**
   A. Amend Att. 6 paragraph 2 to specify that a utility does not have a purchase obligation for DG customers with net capacity greater than 5 MW and nondiscriminatory access to wholesale markets. (Decision Option 3.C)
   B. Amend Att. 6 paragraph 6 to state that the qualifying facility is not excused 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 accessed such nongenerating customers." [*Staff interpretation of Xcel*] (Decision Option 3.A-C)
   C. Amend Att. 6 paragraphs 5 and 6 to align with Minn. Stat. 216B.164, Subd. 4b, which is to specify that that the full avoided capacity and energy costs to be paid a qualifying facility that generates electric power by the 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, Subd. 2, provides that

the use of a renewable resource to meet the identified capacity need is not in the public interest. (Decision Option 3.A)

D. Amend Att. 6 paragraph 7(e) to state that facilities of 100 kW or less are exempt from paying standby charges. (*Xcel, Minnesota Power*) (Decision Option 3.A-B)

AND/OR

6. Undertake additional comments from stakeholders towards identifying and resolving conflicts between Att. 6, state statutes, and FERC Orders.

<u>Regardless of a Determination of Conflicts</u>

7. Refer this matter for further record development on updates to Att. 6 beyond those required to align with federal and state law (*Department)*

OR

Avoided Cost for all DG Tariffs

8. Amend Att. 6 to state that the methodology currently provided in Attachment 6 is the proper rate method for establishing avoided cost rates for DG. (*MCA, HiP, Joint Commenters*)
    A. Add: “to the extent consistent with relevant statutes, rules, and orders.” (*Staff addition*)

Line Loss Credits

9. Amend Att. 6 to adopt the line loss credit methodology as found in the Joint Commenters’ October 30, 2020, Att. 6 Tracked Changes. (*Joint Commenters*)

OR

10. Amend Att. 6 to require utilities to use their line loss information to calculate line loss credits. (*MCA* and *HiP*)

Capacity Look-Back Period

11. Amend Att. 6 to use 15-year periods to measure capacity deficits using the language found in the Joint Commenters’ October 30, 2020, Att. 6 Tracked Changes. (*Joint Commenters*)

OR

12. Amend Att. 6 to specify capacity deficits must be measured using a period based on the projected useful life of the given DG resource. (*MCA and HiP*)

Contract Length

13. Amend Att. 6 to require the utility to offer contract terms up to 25 years using the language found in the Joint Commenters' October 30, 2020, Att. 6 Tracked Changes. (*Joint Commenters*)

OR

14. Amend Att. 6 to state that "contract length should reflect the useful life of the DG system." (*MCA and HiP*)

AND

Other Requested Changes (If the Commission does not choose 1 or 7, any of 15-20 can be paired with previous DOs)

15. Remove the onsite requirement from Att. 6. (*Joint Commenters, City of Minneapolis)*

16. Amend Att. 6 to specify that diversity and reliability credits should be provided to customers not on standby service using the language found in the Joint Commenters' October 30, 2020, Att. 6 Tracked Changes. (*Joint Commenters*)

17. Delegate authority to the Executive Secretary to establish a comment period on further development of a methodology for the calculation of distribution credits. (*Staff interpretation of Joint Commenters*)

18. Amend Att. 6 to value different generation profiles using the language found in the Joint Commenters' October 30, 2020, Att. 6 Tracked Changes. (*Joint Commenters)*

19. Amend Att. 6 to value different generation profiles and require the utility to purchase RECs from the customer at the customer's discretion using the language found in the Joint Commenters' October 30, 2020, Att. 6 Tracked Changes. (*Joint Commenters*)

20. Amend Att. 6 to state that "A DG facility that elects not to receive standby service is exempted from paying any standby charges." (*Joint Commenters*)

<u>General</u>

21. Delegate authority to the Executive Secretary to develop specific language for the

amendments approved in this order, and file an updated Att. 6 with this Order. (*Staff*)

Attachment A: Attachment 6 of the Commissioners September 28, 2004, Order

State of Minnesota

Guidelines for Establishing the Terms of the Financial Relationship Between an Electric Utility and a Distributed Generation Customer with No More Than 10 MW of Capacity

1. AVAILABILITY

The DG customer must connect in parallel to the utility distribution system.

2. QUALIFICATIONS

a. The DG facility must be an operable, permanently installed or mobile generation facility serving the customer receiving retail electric service at the same site.

b. Must buy: The utility must buy all the energy offered for sale by the DG customer selling the power. Utilities that are full requirements customers of wholesale suppliers may need to require the wholesale supplier to assume this obligation in order to abide by contractual requirements with their wholesale supplier.

c. Customer options: Customer may sell all the DG energy to the utility, "sell" all the DG energy to itself, or self-generate part of its needs and sell the remaining energy to the utility.

d. Transactions outside the tariff: DG owners and utilities may pursue reasonable transactions outside the DG tariff. However, such transactions are beyond the scope of the work group.

3. LIST OF SUPPLY SERVICES TO BE PRICED

a. Energy and capacity.

b. Scheduled maintenance service (energy, or energy and capacity, supplied by the utility during scheduled maintenance of the customer's non-utility source of electric energy supply).

c. Unscheduled outages (energy, or energy and capacity, supplied by the utility during unscheduled outages of the customer's non-utility source of electric energy supply).

d. Supplemental service (electric energy, or energy and capacity, supplied by the utility to the DG customer when the customer's non-utility source of electricity is insufficient to meet the customer's own load).

e. Other services deemed necessary.

4. PRINCIPLE OF SETTING RATES FOR SERVICES PROVIDED BY DG CUSTOMERS TO UTILITIES

   Rates should reflect the value of the distributed generation to the utility, including any reasonable credits for emissions or for costs avoided on the generation, transmission, and/or distribution system.

5. PRINCIPLE OF SETTING RATES

   Rates should reflect the costs the utility expects to avoid. To the extent practical, these costs should reflect seasonal and peak/off-peak differences in costs.

6. CALCULATION OF AVOIDED COSTS

   a. Avoided Energy Costs

      Distribution utilities that are full requirements customers of wholesale suppliers may use their suppliers' rate schedules to determine avoided energy costs. Other utilities should follow these steps:

      i. System-wide hourly marginal energy costs are calculated with a production model for each hour of the future year.

      ii. Based on those costs, the average on-peak and off-peak marginal energy costs are calculated for each month.

      iii. The on-peak monthly rate is set at the average monthly on-peak marginal energy costs. The off-peak monthly energy rate is set at the average monthly off-peak marginal costs. Thus, there are 24 rates set for the year, with an on-peak and off-peak rate set for every month.

      iv. A trial period is proposed to see whether, in practice, utilities are able to forecast these energy prices sufficiently well. Depending on the trial results, a lump sum true-up may be used at the end of each year to reflect the difference between actual and estimated energy bills.

   b. Avoided Capacity Costs

      i. Calculate the installed capital cost plus fixed O&M costs plus startup costs ($/kW-year). If the next (marginal) unit is from a competitive bid, the utility must estimate these costs and fully defend the estimate.

      ii. Calculate the Levelized Annual Revenue Requirements (LARR) ($/kW-year).

iii. Divide the amount in (ii) for the next year by twelve to get the capacity marginal costs ($/kW-month).

iv. These marginal costs must be escalated annually by the expected inflation rate.

(1) The need for capacity is established in the utility's most recent integrated resource plan (IRP). A need exists if the utility shows a deficit at any year of the 5-year planning period.

(2) Capacity payments should be made for the total fully accredited DG capacity, regardless of when the power is delivered to the system.

(3) The expected life of a capacity addition is the expected life of the specific capacity addition from the utility's most recently approved integrated resource plan.

(4) If the contract to purchase power from a DG source begins at the time the utility needs the capacity, then the full capacity payment is made, adjusting only as needed for the length of the contract (i.e., there is no discount for adding capacity sooner than it is needed).

(5) The formula for adjustments to capacity payments is:

$$A2 = \frac{(1+i)^m - 1}{(1+i)^n - 1} * \frac{(1+i)^{n-a} - (1+e)^{n-a}}{(1+i)^m - (1+e)^m} * A1$$

Where:
A1= Levelized annual value of a capacity purchase at the time of need.
A2 =Levelized annual value of the capacity paid for in a power purchase contract.
m=Expected lifetime of ordinary (alternative) future capacity addition.
n= Length of power purchase contract.
i= Utility Cost of Capital.
e= Escalation rate affecting value of new capacity additions.
a= Length of time between beginning of contract and time of need for capacity.

7. STANDBY RATES

a. General

i. DG customers do not have to buy standby power. However, if standby power is not purchased, it may not be available.

ii. DG customers do not have to buy as much standby power as necessary to equal the full amount of their own DG capacity. However, if, for example, the customer has a 5 MW DG facility and buys only 2 MW of standby power, there must be a guarantee that the facility will never take more than 2 MW of standby service.

b. Firm Service

i. Generation (capacity): The monthly reservation fees are equal to the percentage of the planned reserve margin of the utility times the applicable capacity tariffed rates.

ii. Transmission: Terms, conditions and charges for transmission service are subject to the individual utilities' or MISO's Open Access Transmission Tariffs or their successors as approved by the FERC.

iii. Local Distribution: The monthly charges equal the monthly charge under the applicable distribution charge. There is no discount in the local distribution charge.

c. Non-Firm Service

i. Generation (energy and capacity): There are no monthly reservation fees for energy and capacity for a non-firm DG customer.

ii. Transmission: There are no monthly reservation fees for transmission for a non-firm DG customer.

iii. Local Distribution: The monthly rates equal the monthly charge under the applicable distribution charges. That is, there is no discount on the distribution charge.

d. Physical Assurance Customer

A physical assurance customer is a customer who agrees not to require standby services and has a mechanical device to insure that standby service is not taken. The cost of the mechanical device, which must be reasonable, is to be paid by the DG customer. A utility's tariff may deal with other issues not addressed here.

e. Maximum Size to Avoid Standby Charge

A DG facility of 60 kW or less is exempted from paying any standby charges. The Commission will review this guideline within 24 months.

8. CREDITS

a. General

Credits should be given to a DG customer if the installation of a DG facility reduces the utility's costs of providing the service. These lower costs could be generation, transmission or distribution related costs.

b. Distribution Credits

i. Distribution credits to a DG customer should equal the utility's avoided distribution costs resulting from the installation of the DG facility.

ii. Each utility should provide, upon request, a list of substation areas or feeders that could be likely candidates for distribution credits as determined through the utility's normal distribution planning process.

iii. Upon receiving a DG application, the utility will perform an initial screening study to determine if the DG project has the potential to receive distribution credits. The DG customer is responsible for the cost of such a screening study.

iv. If the utility's study shows that there exists potential for distribution credits, the utility must, at its own cost, pursue further study to determine the distribution credit, as part of its annual distribution capacity study.

c. Diversity Credit

No additional diversity credits for energy and capacity should be given to DG customers who contract for standby service.

d. Line Loss Credits

No additional line loss credits (above the credits already included in the avoided cost calculations) should be paid to a DG customer with the following exception: A DG customer may request the utility to provide a specific line loss study and receive additional line loss credits if the study supports such credits. The DG customer is responsible for the cost of the study regardless of the study's outcome.

e. Renewable Credits

A DG customer who installs a renewable DG facility should be paid the avoided cost of "green power" to the extent that installation of the DG facility allows the utility to avoid the need to purchase "green power" elsewhere. Otherwise a renewable DG facility should be paid the utility's regular avoided costs.

f. Emission Credits

Tradable Emissions: For tradable emissions such as SO2, if a low emission DG facility allows the utility to capture the value of the emission credit, then the DG owner should receive the credit revenues.

A DG customer may get green credit or an emission credit, but not both.

The Commission's policy regarding the renewable energy objective may affect the question of whether it is reasonable for utilities to pay a credit for renewable power at the approved green-price premium even if a utility does not need the green power.

g. Reliability Credits

DG owners should receive no reliability credit beyond what is already incorporated in the standby tariffs.

Attachment B: Joint Commenters' Att. 6 Tracked Changes

APPENDIX B – REDLINED COPY OF RECOMMENDED ATTACHMENT 6 CHANGES

State of Minnesota

Guidelines for Establishing the Terms of the Financial Relationship Between an Electric Utility and a Distributed Generation Customer with No More Than 10 MW of Capacity

1. AVAILABILITY

The DG customer must connect in parallel to the utility distribution system.

2. QUALIFICATIONS

a. The DG facility must be an operable, permanently installed or mobile generation facility.

b. Must buy: The utility must buy all the energy and capacity offered for sale by the DG customer selling the power. Utilities that are full requirements customers of wholesale suppliers may need to require the wholesale supplier to assume this obligation in order to abide by contractual requirements with their wholesale supplier.

c. Customer options: Customer may sell all the DG energy to the utility, "sell" all the DG energy to itself, or self-generate part of its needs and sell the remaining energy to the utility. The DG facility determines how much energy and capacity it will commit for sale.

d. Transactions outside the tariff: DG owners and utilities may pursue reasonable transactions outside the DG tariff. However, such transactions are beyond the scope of the work group.

3. LIST OF SUPPLY SERVICES TO BE PRICED

a. Energy and capacity.

b. Scheduled maintenance service (energy, or energy and capacity, supplied by the utility during scheduled maintenance of the customer's non-utility source of electric energy supply).

c. Unscheduled outages (energy, or energy and capacity, supplied by the utility during unscheduled outages of the customer's non-utility source of electric energy supply).

d. Supplemental service (electric energy, or energy and capacity, supplied by the utility to the DG customer when the customer's non-utility source of electricity is

Commented [s1]: This change is substantive.

The on-site requirement seems no longer necessary given the breadth of the Interconnection Standards.

Commented [JH2]: This change is not substantive.

This change captures the already-existing requirement that utilities are obligated to purchase energy and capacity from qualifying DG facilities. This change is meant to remove ambiguity.

Commented [JH3]: This change is not substantive.

This change captures the already-existing requirement that DG facilities can determine how much energy and capacity it can sell. This change is meant to remove ambiguity.

insufficient to meet the customer's own load).

e. Other services deemed necessary herein.

4. PRINCIPLE OF SETTING RATES FOR SERVICES PROVIDED BY DG CUSTOMERS TO UTILITIES

Rates should reflect the value of the distributed generation to the utility, including any reasonable credits for emissions or for costs avoided on the generation, transmission, and/or distribution system.

5. PRINCIPLE OF SETTING RATES

Rates should reflect the costs the utility expects to avoid. To the extent practical, these costs should reflect seasonal and peak/off-peak differences in costs.

6. CALCULATION OF AVOIDED COSTS

a. Avoided Energy Costs

Distribution utilities that are full requirements customers of wholesale suppliers may use their suppliers' rate schedules to determine avoided energy costs. Other utilities should follow these steps:

i. System-wide hourly marginal energy costs are calculated with a production model for each hour of the future year.

ii. Based on those costs, the average on-peak and off-peak marginal energy costs are calculated for each month.

iii. The on-peak annual rate is based on the average monthly on-peak marginal energy costs. The off-peak annual energy rate is based on the average monthly off-peak marginal costs. Thus, there are two rates set for the year, with an on-peak and off-peak rate.

iv. The annual on-peak and off-peak energy rate must be escalated annually by the expected inflation rate.

b. Avoided Capacity Costs

i. Calculate the installed capital cost plus fixed O&M costs plus startup costs ($/kW-year). If the next (marginal) unit is from a competitive bid, the utility must estimate these costs and fully defend the estimate.

ii. Calculate the Levelized Annual Revenue Requirements (LARR) ($/kW-year).

Commented [JH4]: This change is substantive.

This change is meant to simplify the avoided energy cost rate. Rather than having 24 different monthly on-peak and off-peak rates, there will now just be 2 different rates: on-peak and off-peak. This should not result in materially different rates than the former monthly rates, but it will result in more simplicity.

Commented [JH5]: This change is substantive.

The old Attachment 6 has similar language for escalating capacity costs (which is still retained below), and the language added to the energy rate section is based on that prior language in the capacity rate section. Adding this language to the energy rate section creates a simple method of forecasting avoided energy rates over long-term, multi-year contracts.

iii. Divide the amount in (ii) for the next year by twelve to get the capacity marginal costs ($/kW-month).

iv. These marginal costs must be escalated annually by the expected inflation rate.

(1) The need for capacity is established in the utility's most recent integrated resource plan (IRP). A need exists if the utility shows a deficit at any year in the IRP's 15-year planning period.

(2) Capacity payments should be made for the total fully accredited DG capacity, regardless of when the power is delivered to the system.

(3) The expected life of a capacity addition is the expected life of the specific capacity addition from the utility's most recently approved integrated resource plan.

(4) If the contract to purchase power from a DG source begins at the time the utility needs the capacity, then the full capacity payment is made, adjusting only as needed for the length of the contract (i.e., there is no discount for adding capacity sooner than it is needed).

(5) The formula for adjustments to capacity payments is:

$$A2 = \frac{(1+i)^m - 1}{(1+i)^n - 1} * \frac{(1+i)^{n-a} - (1+e)^{n-a}}{(1+i)^m - (1+e)^m} * A1$$

Where:
Al = Levelized annual value of a capacity purchase at the time of need.
A2 = Levelized annual value of the capacity paid for in a power purchase contract.
m = Expected lifetime of ordinary (alternative) future capacity addition.
n = Length of power purchase contract.
i = Utility Cost of Capital.
e = Escalation rate affecting value of new capacity additions.
a = Length of time between beginning of contract and time of need for capacity.

c. Technology-specific Renewable Avoided Cost

A DG customer who installs a renewable DG facility should be paid the avoided cost of "green power" to the extent that installation of the DG facility allows the utility to avoid the need to build or purchase "green power" elsewhere. Otherwise a renewable DG facility should be paid the utility's regular avoided costs, as calculated above.

"Green power" is defined as the specific renewable technology that the utility would

Commented [JH6]: This change is substantive.

A 15-year planning period corresponds with the 15-year planning period that already exists in an IRP. This also ensures that DG facilities are adequately compensated. Under a 5-year framework, it is nearly impossible to receive any capacity credit, as demonstrated by the fact that there has been no DG facility utilizing the DG Tariff.

Commented [JH7]: This change is substantive.

The language of the first paragraph is largely lifted from the old Attachment 6, *infra* page 5 of 6, from a subsection titled "Renewable Credit." That subsection allowed technology-specific avoided cost rates, but it was ambiguous as to what such rates entailed. This language attempts to provide clarity.

otherwise need to build or purchase. For example, if a utility must build or purchase solar energy to comply with a technology-specific requirement imposed by state law or Commission order, then 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.

The Commission's policy regarding the renewable energy objective may affect the question of whether it is reasonable for utilities to pay a credit for renewable power at the approved green-price premium even if a utility does not need the green power.

7. STANDARD CONTRACT TERM LENGTH

Commented [JH8]: This change is substantive.

Long-term contracts are necessary in order for DG customers to obtain financing for their DG facilities. 25 years is the time period most utility capacity additions are measured and 25 years is long enough to ensure DG customers have reasonable access to financing.

The utility must offer contract terms up to 25 years in length with fixed rates.

8. STANDBY RATES

a. General

i. DG customers do not have to buy standby power. However, if standby power is not purchased, it may not be available.

ii. DG customers do not have to buy as much standby power as necessary to equal the full amount of their own DG capacity. However, if, for example, the customer has a 5 MW DG facility and buys only 2 MW of standby power, there must be a guarantee that the facility will never take more than 2 MW of standby service.

b. Firm Service

i. Generation (capacity): The monthly reservation fees are equal to the percentage of the planned reserve margin of the utility times the applicable capacity tariffed rates.

ii. Transmission: Terms, conditions and charges for transmission service are subject to the individual utilities' or MISO's Open Access Transmission Tariffs or their successors as approved by the FERC.

iii. Local Distribution: The monthly charges equal the monthly charge under the applicable distribution charge. There is no discount in the local distribution charge.

c. Non-Firm Service

i. Generation (energy and capacity): There are no monthly reservation fees for energy and capacity for a non-firm DG customer.

ii. Transmission: There are no monthly reservation fees for transmission for a non-firm DG customer.

iii. Local Distribution: The monthly rates equal the monthly charge under the applicable distribution charges. That is, there is no discount on the distribution charge.

d. Physical Assurance Customer

A physical assurance customer is a customer who agrees not to require standby services and has a mechanical device to insure that standby service is not taken. The cost of the mechanical device, which must be reasonable, is to be paid by the DG customer. A utility's tariff may deal with other issues not addressed here.

e. Maximum Size to Avoid Standby Charge

A DG facility that determines it will not need standby service is exempted from paying any standby charges.

9. CREDITS

a. General

Credits should be given to a DG customer if the installation of a DG facility reduces the utility's costs of providing the service. These lower costs could be generation, transmission or distribution related costs.

b. Distribution Credits

i. Distribution credits to a DG customer should equal the utility's avoided distribution costs resulting from the installation of the DG facility.

ii. Each utility should provide, upon request, a list of substation areas or feeders that could be likely candidates for distribution credits as determined through the utility's normal distribution planning process.

iii. Upon receiving a DG application, the utility will perform an initial screening study to determine if the DG project has the potential to receive distribution credits. The DG customer is responsible for the cost of such a screening study.

iv. If the utility's study shows that there exists potential for distribution credits, the utility must, at its own cost, pursue further study to determine the distribution credit, as part of its annual distribution capacity study.

c. Diversity & Reliability Credit

i. No additional Diversity & Reliability Credits for energy and capacity should be given to DG customers who contract for standby service.

Commented [JH9]: This change is substantive.

Attachment 6 already specified that a DG customer can determine how much energy and capacity it wants to sell, which Movants attempt to clarify *infra* page 1 of 6, and this change clarifies how standby charges are charged. It would be discriminatory and unfair to allow a utility to charge a DG facility—regardless of size—for standby service if the DG facility has reasonably determined that it will not need standby service.

Commented [JH10]: This change is not substantive.

This change removes reference to a Commission promise to review this section in 2006. Movants are unaware of whether the Commission ever conducted such a review.

ii. Diversity & Reliability Credits shall be provided for customers that are not on standby service and shall be equal to the amount of reserve capacity it requires to back up a supply of electricity from smaller generators. This 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.

d. Line Loss Credits

A line loss credit should be applied to the avoided energy cost rate by multiplying it by the utility's system wide line loss factor plus 1. The calculation is:

$$A2 = (1 + a) * A1$$

Where:

A1 = avoided energy cost rate
A2 = avoided energy cost rate modified by line loss factor
a = system wide line loss factor (expressed as a percent)

For example, if a = 2.2% and A1 = $.04/kWh, then A2 = $.04088

No additional line loss credits (above the credits already included in the avoided cost calculations) should be paid to a DG customer with the following exception: A DG customer may request the utility to provide a specific line loss study and receive additional line loss credits if the study supports such credits. The DG customer is responsible for the cost of the study regardless of the study's outcome.

e. Renewable Energy Credits (RECs)

A DG facility retains RECs generated by its DG facility.

However, if a DG customer qualifies for a technology-specific "green power" avoided cost and opts for the "green power" rate, *supra* § 6.c, then the DG facility must agree to transfer its REC to the utility without additional compensation for the REC because the difference between the utility's avoided cost and its "green power" avoided cost already compensates the DG facility for the "green power" represented by the REC.

Commented [s11]: This change is substantive.

This change combines diversity and reliability credits, and the formula for calculating them is taken from the Value of Solar Methodology and replicated to fit a "model" DG facility. *See* In the Matter of Establishing a Distributed Solar Value Methodology under Minn. Stat. § 216B.164, subd. 10 (e), Docket No. 14-65, Order, Attachment titled MINNESOTA VALUE OF SOLAR – METHODOLOGY at 18 (Apr. 11, 2014).

Commented [JH12]: This change is substantive.

In the old version of Attachment 6, its language (which is retained here) made reference to line loss credits included in the avoided cost calculations. However, nowhere in Attachment 6 nor the Commission's September 2004 Order was there any guidance on how line losses would be included in the avoided cost calculations.

This change provides a simple calculation of how line losses should be included in the avoided cost calculation, and it is based on a similar formula that Michigan uses to apply line loss credits to its avoided cost calculation.

Commented [JH13]: This change is not substantive.

This language was moved to § 6, which deals with avoided costs. This language allows technology-specific avoided costs and it was unclear why it was outside of the avoided cost section.

Commented [JH14]: This change is substantive.

In the old Attachment 6, it stated that a DG customer cannot receive both (1) emission credits and (2) "green power" credits. This seemed equitable because the "green power" credit was really technology-specific renewable avoided costs and because emission credits are commonly captured by renewable facilities as RECs. It would be unfair to allow a DG facility to obtain both technology-specific renewable avoided costs and RECs.

This change clarifies that DG facilities retain their RECs under the regular avoided cost rate but allows the utility to obtain the RECs under technology-specific renewable avoided cost rates, since this "green power" rate includes compensation to the DG facility for the RECs it generates.