

**STATE OF MINNESOTA
PUBLIC UTILITIES COMMISSION**

Nancy Lange	Chair
Daniel Lipschultz	Commissioner
Matt Schuerger	Commissioner
Katie Sieben	Commissioner
John Tuma	Commissioner

**In the Matter of Establishing Generic
Standards for Utility Tariffs for
Interconnection and Operation of
Distributed Generation Facilities Under
Minn. Stat. § 216B.1611**

**MNSEIA, MNSEIP, ELPC, ISLR,
MCEA, CEEM & MN BROWNFIELDS’
MOTION TO REOPEN AND AMEND
THE DISTRIBUTED GENERATION
TARIFFS**

March 23, 2018

Docket No. E-999/CI-01-1023

**MOTION OF THE MINNESOTA SOLAR ENERGY INDUSTRIES ASSOCIATION &
PROJECT, THE ENVIRONMENTAL LAW AND POLICY CENTER, THE
MINNESOTA CENTER FOR ENVIRONMENTAL ADVOCACY, THE INSTITUTE
FOR LOCAL SELF RELIANCE, CLEAN ENERGY ECONOMY MINNESOTA AND
MINNESOTA BROWNFIELDS**

INTRODUCTION

In accordance with Minn. Stat. § 216B.25,¹ the Minnesota Solar Energy Industries Association & Project, 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 (collectively “Movants”) respectfully move the Minnesota Public Utilities Commission (“Commission”) to reopen the portion of Docket No. CI-01-1023 pertaining to rates for distributed generation (“DG”) facilities and the DG Tariff under Minn. Stat. § 216B.1611, subd. 3. This request is similar, but different from, the motion made by the Movants in this Docket on June 6, 2016, which primarily concerned Interconnection Standards. This motion is specifically to review the DG Tariff framework found in the Commission’s

¹ Minn. Stat. § 216B.25 provides the Commission with authority to “rescind, alter, or amend any order” made by the Commission, or “reopen any case ... for the taking of further evidence or for any other reason.” The Commission may reopen a case or amend a prior order “at any time, on its own motion or upon motion of an interested party.” Any order rescinding, altering, amending, or reopening a prior order shall have the same effect as an original order.

September 2004 Order establishing the DG Tariffs.² In so doing, the Movants also request the Commission use this opportunity to review the State’s avoided cost methodology generally, as avoided cost rates are the underpinning of DG Tariff rates.

The Commission created the DG Tariff framework in September 2004, but to the Movants’ knowledge, no DG facility has taken service under the DG Tariff. The lack of DG Tariff activity is due to the DG Tariff framework’s failure to achieve its original intention. The original intention of the DG Tariff was to tap into the power of DG and its benefits, which include “reducing the demand on long distance transmission lines, enhancing reliability, ameliorating environmental consequences and increasing customer choice.”³

According to the Commission’s September 2004 Order, the DG Tariff’s rate was meant to be an avoided cost rate—separate rates for avoided energy and avoided capacity costs—with additional compensation to DG facilities for non-energy benefits they provide to a utility, which included distribution credits, diversity credits, line loss credits, renewable credits, emission credits, and reliability credits.⁴

The DG Tariff is available to DG facilities 10 MW or smaller.⁵ The rate should be a value somewhere between avoided cost and the Value of Solar (“VOS”). The DG Tariff should be a mechanism to encourage the deployment of DG across the entire state of Minnesota and should foster our state’s renewable energy goals. There should also be incentives for the utilities that best deploy DG facilities.⁶ In order to achieve these goals, the rate methodology must be reformed and modernized because the current DG Tariffs are unworkable for DG system deployment, as evidenced by the fact that no utility has customers taking service under the tariff.

As will be illustrated below, the time to address DG Tariff rates and implementation is now. With declining costs in many DG facility types, it is paramount that the Commission revisit its rules to ensure developers have a realistic route to attain fair DG rates and adequate contract term-lengths. This will help avoid future DG developer disputes, save time for all parties and encourage more DG deployment throughout Minnesota to address increasing public demand for access to solar energy.

In support of the motion, Movants state the following:

SUMMARY OF REQUESTED RELIEF

The Movants request that the Commission create a new working group to study and solicit feedback on the rate portion of the DG Tariff. Similar to how the original DG Tariff was

² See *In re Establishing Generic Standards for Utility Tariffs for Interconnection and Operation of Distributed Generation Facilities under Minnesota Laws 2001, Chapter 212*, Docket No. CI-01-2013, Order, (Sept. 28, 2004) (“September 2004 Order”) available at <https://perma.cc/KS4D-9HZ2>

³ September 2004 Order at 3 available at <https://perma.cc/KS4D-9HZ2>

⁴ *Id.*, Attachment 6 at 2-6.

⁵ See Minn. Stat. 216B.1611, subd. 2.

⁶ See Minn. Stat. 216B.1611, subd. 2(b).

developed with a Technical Working Group and a Rate Working Group, this process could be done independently from the ongoing Interconnection Standards process in Docket No. CI-16-521. A separate docket and working group is appropriate given the current scope and stakeholder makeup of the Interconnection Standards working group.

Should the Commission decline to create a new docket, our request can also be treated as Interconnection Standards Phase III and be set for 2019 after the Interconnection Standards and Interconnection Technical Standards working groups have completed their scope of work. If this pathway were selected, this request could also partially be handled by the new DG Advisory Group if their agenda permits initial discussion prior to 2019.⁷ With so many important working groups already in existence, the Movants hope to have this item addressed in the most convenient way for the Commission and its staff without sacrificing expediency.

As a starting point, the Movants are attaching their proposed revisions to the DG Tariff's framework regarding rates. These proposed revisions update the original Attachment 6 accompanying the Commission's September 2004 Order. Exhibit A attached to this Motion are Movants' proposed revised Attachment 6 and Exhibit B is a redline version demonstrating the changes Movants propose and the reason behind each proposed change.

BACKGROUND

1. The Commission's Order Establishing the DG Tariff.

On September 28, 2004, the Commission issued an order establishing the DG Tariff.⁸ As the Commission recognized, "[w]hether distributed generation is financially viable to the generator, or is unduly burdensome to the utilities, depends in part on how [DG Tariff rates] are set." *Id.* at 6. Since the September 2004 Order, the Commission has not updated the rate portion of the DG Tariff.

Distributed generation, or "DG," refers to the practice of generating electricity with multiple, dispersed power plants. Many benefits have been attributed to DG, including "reducing the demand on long-distance lines, enhancing reliability, ameliorating environmental consequences and increasing customer choice." *Id.* at 3. In requiring utilities to purchase from DG facilities under the DG tariff, the Commission explained:

The Legislature adopted Minnesota Statutes § 216B.1611 to simplify the process of analyzing the viability of a DG project, and to streamline the process of implementing such projects. Standardized provisions, such as a "must buy" clause, are necessary to streamline the process for the benefit of both the customer

⁷ The initial DG Advisory Committee lists rate issues, such as the DG Tariff, as "outside of scope" and this issue may be too time intensive and contentious for that group to handle directly. Further, the group's initial meeting stressed a desire to deal with easy to deal with issues, so a challenge like the DG Tariff would likely be discussed towards the end of an already lengthy agenda and this issue is important to address as soon as is practicable to ensure near-term DG deployment.

⁸ September 2004 Order available at <https://perma.cc/KS4D-9HZ2>

and the utility.

Id. at 9. The Commission announced the following two guiding principles for DG Tariff rates:

Principle One: 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.

Principle Two: 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.

Id. at 10. Expanding on Principle One, the Commission explained that “[c]redits should be given to a DG customer if the installation of a DG facilities reduces the utility’s cost of providing the service. These lower costs could be generation, transmission or distribution related costs.” *Id.* at 22.

MOTION SUPPORT

1. The DG Tariffs Were Originally Drafted At The Same Time As The Interconnections Standards, And If Those Are Outdated And Warrant Re-Review, The DG Tariffs Are Also Outdated.

The DG Tariff is out of date and should be revisited for five key reasons:

First, several new advancements in DG technology and understanding has made this issue ripe for review. Significant advances in technology and a general understanding of DG costs – like the VOS Methodology – and the need for financing have given stakeholders a better understanding of what components and values should be in the DG Tariff.

Second, on January 24, 2017, the Commission determined that the original Interconnection Standards were out-of-date and required revision.⁹ Likewise, because the current DG Tariff framework was issued at the same time as the original Interconnection Standards, the DG Tariff is also out-of-date and requires revision.

Third, disputes are occurring because of the current ineffectual state of the DG Tariff. In Docket No. 16-1021, a complainant DG developer sought to access financing for its less than 10 MW facility through both the utility’s PURPA¹⁰ tariff and DG Tariff, but was unable to use either rate to build the project.

⁹ See *In the Matter of Updating the Generic Standards for the Interconnection and Operation of Distributed Generation Facilities Established under Minn. Stat. § 216B.1611*, Docket No. CI-16-521, Order, (January 24, 2017) available at <https://perma.cc/3JK7-YYT2>

¹⁰ Public Utility Regulatory Policies Act, Pub.L. 95–617, 92 Stat. 3117.

Fourth, the DG Tariff's applicable statute contemplates utility incentives for on-site DG, but because the Commission has not contemplated or revisited this issue since its original September 2004, no incentives have been considered or implemented.¹¹

Fifth, utilities are currently not applying their DG Tariffs correctly. For instance, under the DG Tariff methodology, Otter Tail Power is required to provide compensation for Distribution Credits and Line Losses, but their published tariff does not include these values.¹² It reads as a tariff solely for avoided cost pricing.

Fifth, our understanding – which may be incorrect due to the DG Tariff rate's trade-secret status – is that in each utility's service territory the DG Tariff price is currently hovering around its avoided cost price. This is odd given the relatively higher rate of the VOS, which is supposed to be similar to the DG Tariff in that VOS captures avoided costs plus other compensation for solar's DG benefits. An updated DG Tariff rate methodology could be appropriate given this unusual outcome.

The VOS as a rate is presumably three-to-five times higher than a given utility's avoided cost rate. Part of the reason the VOS is significantly higher than the utility's avoided cost is because it incorporates (1) the utility's avoided costs and (2) additional benefits solar provides to the utility, which are due to solar's distributed nature. Thus, it seems that the DG Tariff should, if it is constructed in accordance with Minn. Stat. § 216B.1611 and the September 2004 Order, be somewhere between the utility's avoided cost and the VOS. The VOS was considered over a lengthy stakeholder process after Minn. Stat. § 216B.164 was amended in 2013. The information gathered from that process alone would surely inform the Commission's inquiry into the DG Tariffs.

2. To The Movants' Knowledge, No DG Facility Has Ever Used A DG Tariff In Minnesota.

The Commission should revisit the DG Tariff and its framework because, to the Movant's knowledge, no DG Facilities have ever successfully taken service under DG Tariff since its inception over 13 years ago. This should be a red flag for the Commission to take corrective action. The lack of DG Tariff activity is in large part due to several decisions made when the DG Tariff was originally formulated that make the DG Tariff unusable.

The Commissions' two DG Tariff rate principles¹³ state:

Principle One: 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.

¹¹ Minn. Stat. § 216B.1611, subd. 2. (5)(b).

¹² See REPORT – DISTRIBUTED GENERATION, Ottertail Power, Docket No. E999/PR-17-10, Doc. Id. 20171-128706-02 (Jan. 31, 2017).

¹³ September 2004 Order at 10.

Principle Two: 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.

The DG Tariff does not accomplish the Commission's two principles. For instance, how a utility calculates capacity pricing according to the September 2004 Order is overly onerous on the DG Facility because it will generally be \$0. This is the case because the DG Tariff only compensates DG Facilities for capacity if the contracting utility has a capacity need within 5 years.¹⁴

Because utilities generally plan at least 15-years out, they tend to have their capacity needs met well before this 5-year period applies. This has a peculiar effect of having long-term DG contracts where a utility needs capacity 6+ years out as stated in their most recent IRP, but the DG facility will get no capacity value for the duration of the entire contract (if the contract term is set above 5 years) even if the term is 25 years or longer. The Commission originally arrived at the 5-year window despite the statute clearly stating that one of the purposes of Minn. Stat. 216B.1611 is to "promote the use of distributed resources in order to provide electric system benefits during periods of capacity constraints." The Commission's original 5-year window makes it hard to obtain capacity credit under the DG Tariff.

Another example of why the DG Tariff is unused is the credit for line-losses. Currently, the DG Tariff does not permit DG facilities to get credit for line-losses, unless they complete a line-loss study.¹⁵ The study, however, is often more expensive than the expected associated benefit of the line-loss credit. Accordingly, no DG facility can actually take advantage of this benefit.

The scope of the DG Tariff framework has failed to keep up with our knowledge of the benefits of DG. For example, the VOS may now instruct the Commission about additional benefits that were not previously considered in the original DG Tariff proceedings, and the Value of Solar also shows why the known benefits should now be revisited in order to make the DG Tariff useable for the first time.

3. A Dispute Recently Arose Because There Is No Good Financing Mechanism For DG Facilities In Minnesota, And More Disputes Are Likely To Proceed As Solar And Wind Prices Decline.

Reopening the DG Tariff will help avoid future disputes because common issues that arise can be standardized and avoided. For instance, in Docket No. E017/CG-16-1021 a dispute arose between Red Lake Falls Community Hybrid, LLC, a DG Facility, and Otter Tail Power. The main issues in the dispute are contract length and rate price. Throughout the negotiation process prior to the complaint, the DG Tariff was discussed. However, because the DG Tariff

¹⁴ September 2004 Order at 15.

¹⁵ *Id.* at 25.

rate was too low and tied to a 10-year contract duration - despite it being designed exactly for systems like the 4.6 MW facility in that dispute - Red Lake Falls was forced to file a dispute resolution proceeding under Minn. Stat. § 216B.164, subd. 5.

As the evidence in that record shows and as Commissioners highlighted at the recent Docket E017/CG-16-1021 hearing, the parties were not that far apart prior to the dispute being filed. The parties likely could have reached an amicable resolution if the DG Tariff had been modernized going into the discussion. With a widearray of potential decision options on the table for the Commission in that Docket, it seems clear that without modernization of the utility DG Tariffs, more DG disputes are likely.

Correct and accurate rates are very important to the DG community because such rates determine whether projects get financed. A similar issue to the Red Lake Falls proceeding was filed in Docket No. E-002/M-13-867 over Xcel's handling of its 2018 Community Solar VOS rate, wherein developers showed that without good, workable rates disputes are inevitable between a DG facility and the utility.¹⁶ Reopening the DG Tariff to revise its rate methodology and other issues, like contract length, can avoid future disputes.

Further, within the confines of Docket No. CG-16-1021, the Competitive Clean Energy Advocates requested the Commission establish a working group to specifically review avoided cost pricing.¹⁷ Since avoided costs underpin the DG Tariff methodology, it would be a prudent investment of time for the Commission to establish a scope of work for a DG Tariff Rate Working Group that includes a review of avoided costs and the DG Tariff rate. Further, if the dispute between Red Lake Falls Community Hybrid, LLC and Otter Tail settles, the Commission will be procedurally unable to adopt the Competitive Clean Energy Advocates' request.¹⁸

The Commission has seemed inclined to not have its orders in one docket be used as binding precedent in other dockets. This is within the Commission's purview to do, but it provides little guidance and no regulatory certainty for future developers and utilities. Without precedent or findings to rely upon, parties are forced to file individual complaints, which take up precious time the Commission could be devoting to other matters.

If a work group is not established, DG developers that seek to build under either the DG Tariff or Avoided Cost rates generally will first negotiate with the utility but will likely be forced to file disputes based on a lack of modernized guidance for DG rates calculation. Without change to the rate methodologies there will ultimately be more situations like Red Lake Falls Community Hybrid, LLC v. Otter Tail Power. Disputes are problematic for both the utility and the developer. Under Minn. Stat § 216B.164, subd. 5 the utility may have to pay the disputant's legal fees and other associated costs. Presumably these costs are passed on to the ratepayers.

¹⁶ See BRIEFING PAPERS, MARCH 1, 2018 AGENDA, PUC, Docket No. E-002/M-13-867, Doc. Id. 20182-140349-01 (Feb. 21, 2018).

¹⁷ See REPLY BRIEF, Competitive Clean Energy Advocates, Docket No. E017/CG-16-1021, Doc. Id. 201711-137418-01 at 2 (Nov. 16, 2017).

¹⁸ This request for the parties to continue negotiations was verbally ordered at the February 27, 2018 hearing in docket 16-1021 in an order yet to be published.

These costs will continue to grow as the disputes continue to be filed. Conversely, disputes are very time intensive. Losing time is often the same as losing a project, and a protracted hearing process may kill many good projects. Finally, disputes are not good for the Commission either. Each dispute will utilize consumer PUC resources and time at the expense of other more important docket items.

The Commission's best course of action would be to establish a working group to head off these issues before they arise, which can be accomplished through granting this Motion. A working group is the best venue to handle this issue because its findings and subsequent Commission adoption would reduce the likelihood of future disputes.

4. The Statute Contemplates Utility Incentives For DG Deployment But Such Incentives Have Never Been Considered.

The Commission should consider promulgating incentives under existing Minnesota law. To our knowledge the Commission has never provided for utility incentives under the DG Tariff framework, even though Minnesota law allows it.¹⁹ Minnesota law allows the Commission to “develop financial incentives based on a public utility’s performance in encouraging residential and small business customers to participate in on-site generation.”²⁰ These incentives could come as a permitted revenue increase, or other utility financial incentive.

Utilities across America have been reluctant to adopt DG-friendly policies at times, because they are able to build their own projects and rate-base them; DG facilities are often not owned by the utility. Having appropriate incentives in place can help mitigate this disincentive towards DG facilities, and the statute permits incentives like this. Utilities should be encouraged to promote DG deployment and our hope is that the working group will tackle that issue as part of its scope.

With the Grid Modernization and e-21 initiatives underway and most utilities expressing a challenge in either meeting their renewable energy standard, solar energy standard or their small-scale solar energy standard, now is the time to have the conversation about utility compensation for having more DG facilities on their system. In a DG Tariff Rate Working Group, the Movants will work collaboratively with utilities and other stakeholders to develop a new DG Tariff framework that will expand DG across the state and reward the utilities for doing so. As such, any review into the DG Tariff should come with a utility incentive program to encourage more DG deployment.

5. The DG Tariffs Are So Old That Various Aspects Of The September 2004 Order Are No Longer Present In The Utility Tariffs.

Since the DG Tariffs were created in 2004, various aspects of the original framework are now not included in some of the utilities’ DG Tariffs. For example, in Otter Tail’s annual DG

¹⁹ Minn. Stat. § 216B.1611, subd. 2(b)

²⁰ *Id.*

Tariff filing it has information on an Energy Payment Schedule, Capacity Payment Schedule, Emissions Credits, and Renewable Credits, but their DG Tariff filing does not give DG customers credit for Distribution Credits or Line-Losses, as required by the September 2004 Order.²¹

Otter Tail's DG Tariff reads as if the DG Tariff is simply an avoided cost price, even though the DG Tariff rate was intended to be avoided cost rate and additional compensation for the benefits that distributed generation provides to the utility. That is not to say that Otter Tail will not provide those credits upon request, but their tariff that outlines what the customer can apply for no longer includes those benefits. Various functions of the order have slowly been lost to time.

Considering Otter Tail's obligation to revise its tariffs to include all of the old Order points, now is the perfect time to review the entire DG Tariff so that their update can include any additional changes that stem from that work group process.

6. The September 2004 Order Has Ambiguous Components That Necessitate Reevaluation.

The September 2004 Order also contains what appear to be mistakes or not fully fleshed-out concepts, which require revisiting in their own right. Under the topic of "Diversity Credits," the Commission concludes that "No additional diversity credits for energy and capacity should be given to DG customers who contract for standby service."²² But the Commission does not allude to whether it should permit Diversity Credits for non-standby systems. In fact, it suggests that Diversity Credits should be applied, but makes no definitive statement one way or another.

No utility has decided to interpret this language as allowing or requiring Diversity Credits, as it is not present in any of their tariffs. This reason alone should warrant a review of this tariff.

7. The September 2004 Order Is Missing Some Critical Components For Modern Distributed Generation Deployment, Like Term-Length, Energy Storage Benefits And An Outdated Requirement For On-Site Distributed Generation.

There are two key components missing in the current DG Tariff, in addition to its outdated requirement for on-site distributed generation.

First, the Distributed Generation Tariff currently does not discuss contract term length. Contract term length for the DG Tariff is decided by the utility. This variable, when left up to the utility, is significant enough to render the DG Tariff useless. To date this process has resulted in 10-year terms, which are too low to finance appropriately. For instance, Minnesota utilities tend

²¹ See REPORT – DISTRIBUTED GENERATION, Ottertail Power, Docket No. E999/PR-17-10, Doc. Id. 20171-128706-02 (Jan. 31, 2017).

²² September 2004 Order at 15.

to finance their own projects on 25-year terms and Xcel's Community Solar Gardens program also provides 25-year terms for those distributed systems. In *Red Lake Falls Community Hybrid, LLC v. Otter Tail Power*, Docket No. 16-1021, one of the three central issues in dispute is contract length. While that dispute is not yet settled, the Administrative Law Judge recommended 20-year terms.²³

The lack of a term length in the DG Tariff is a significant reason why there is currently no DG Tariff activity. Having a 20-year to 25-year term allows DG developers to finance the project on a significantly lower rate. This benefits ratepayers and the Distributed Generation facility. Not having a term-length flies in the face of the DG Tariffs original purpose. According to the Commission "the potential for these [distributed generation] benefits would be lost, however, if the process of connecting small generators to the electrical grid proved too dangerous, or the process of negotiating such connections proved too burdensome."²⁴ But without a set term length, the utility has all the bargaining power in setting term length and therefore the current process is "too burdensome" on DG developers.

Second, the DG Tariff is currently missing any real valuation for storage capabilities. The DG facility of the future is a Distributed Energy Resource ("DER"). A DER will have the capability to produce power and store it for later use. Now is a great opportunity to modernize the DG Tariffs to incorporate storage benefits and DERs.

CONCLUSION

Wherefore, in consideration of the reasons stated above, the Movants respectfully request that the Commission either:

(1) Create a new docket and working group to investigate the DG Tariff's implementation and include an investigation into the proper avoided cost methodology; or

(2) Reopen the DG Tariff rate portion of Docket No. CI-16-521, include an investigation into the proper avoided cost methodology and permit the Interconnection Standards Working Group to address these issues in a Phase III process.

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²³ See REPORT, OAH, Docket No. E-017/CG-16-1021, Doc. Id. 201712-138448-01 at 2 (Dec. 27, 2017).

²⁴ September 2004 Order at 3.

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ATTACHMENT 6
RATES

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 insufficient to meet the customer's own load).
- e. Other services deemed necessary herein.

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

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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:

- 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.

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 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-

ATTACHMENT 6 RATES

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

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

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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.
- 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

ATTACHMENT 6 RATES

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.

ATTACHMENT 6
RATES

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 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.

Comment [s1]: This change is substantive.

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

Comment [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.

Comment [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.

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 herein.

ATTACHMENT 6 RATES

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-annual~~ rate is ~~set at~~based on the average monthly on-peak marginal energy costs. The off-peak ~~monthly-annual~~ energy rate is ~~set based on~~at the average monthly off-peak marginal costs. Thus, there are ~~24~~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. ~~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.

Comment [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.

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Comment [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.

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ATTACHMENT 6 RATES

- 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~~ 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:

- 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.

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

Comment [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.

Comment [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.

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ATTACHMENT 6 RATES

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

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

Comment [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.

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87. 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.

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

Comment [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.

Comment [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.

89. 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.

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ATTACHMENT 6 RATES

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.

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Comment [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).

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)

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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.

Comment [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.

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.

ef. ~~Emission Credits~~ Renewable Energy Credits (RECs)

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 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.

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Comment [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.

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ATTACHMENT 6 RATES

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

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~~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.~~

Comment [JH14]: This change is substantive.

~~fg. Reliability Credits~~

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

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.

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