Minnesota Public Utilities Commission

Staff Briefing Papers

Meeting Date: August 24, 2017 ..... Agenda Item **#_11_**

Companies: Xcel Energy (Xcel)
Minnesota Power (MP)
Otter Tail Power Company (OTP)
Dakota Electric Company (DEA)

Docket Number: **E-999/CI-15-115**

In the Matter of a Commission Inquiry into Standby Service Tariffs

Issues: Should the Commission approve, reject or approve with modification the standby service tariffs filed by Xcel, MP, OTP and DEA?

Should the Commission delay approval of any of the utility-proposed tariffs and require additional processes in order to make further revisions, including further standardization, to the utility-proposed standby service tariffs?

Should the Commission approve Xcel's Solar PV Capacity Credit Rider, including the current level of the solar capacity credit?

Staff: Susan Mackenzie | 651.201.2241 | susan.mackenzie@state.mn.us

---

Relevant Documents

Order Requiring Tariff Filings (in Docket No. 15-115) ..... issued November 19, 2015

Utility standby service tariff filings (Docket No. 15-115):

Otter Tail Power Company (OTP) ..... May 18, 2016
Xcel Energy (Xcel), Public and Non-Public ..... May 19, 2016
Minnesota Power (MP) ..... May 19, 2016
Dakota Electric Company (DEA) ..... May 19, 2016

Parties' comments (Docket No. 15-115):
City of Minneapolis ..... August 18, 2016
Midwest Cogeneration Association/Fresh Energy (MCA/FE) ..... August 19, 2016
Minnesota Energy Storage Alliance (MESA) ..... August 19, 2016
Minnesota Solar Energy Industries Association (MnSEIA) ..... August 19, 2016
iDeal Energies ..... August 19, 2016

Energy Resources Center ..... August 19, 2016
A Work of Art ..... August 19, 2016
Novel Energy Solutions ..... August 19, 2016
Sundial Solar ..... August 19, 2016
Metropolitan Council ..... August 19, 2016
Sam's East/Wal-Mart Stores East ..... August 19, 2016
Renewable Energy Services ..... August 19, 2016
Department of Commerce (DOC or the Department) ..... August 22, 2016
Sundial Solar ..... October 10, 2016
Otter Tail Power Company (OTP) ..... November 9, 2016
MCA/FE ..... November 9, 2016
Large Power Intervenors (LPI) ..... November 9, 2016
City of Minneapolis ..... November 9, 2016
Minnesota Power (MP) ..... November 9, 2016
Xcel Energy (Xcel) ..... November 9, 2016
Dakota Electric Association (DEA) ..... November 9, 2016
MnSEIA ..... November 9, 2016
Department of Commerce (DOC) ..... November 9, 2016

PUC notice seeking updated comments ..... issued February 17, 2017

Energy Concepts ..... April 19, 2017
Winona Renewable Energy ..... April 19, 2017
Innovative Power Systems ..... April 19, 2017
Solar Farm ..... April 19, 2017
All Energy Solar ..... April 20, 2017
Novel Energy Solutions ..... April 20, 2017
Flint Hills Resources Pine Bend ..... April 21, 2017
Sundial Solar ..... April 21, 2017
iDEAL Energies ..... April 21, 2017
Otter Tail Power Company (OTP) ..... April 21, 2017
Xcel Energy (Xcel) ..... April 21, 2017
MCA/FE ..... April 21, 2017
University of Minnesota ..... April 21, 2017
Department of Commerce (DOC) ..... April 21, 2017
Large Power Intervenors (LPI) ..... April 21, 2017
Target Corporation ..... April 21, 2017
Ameresco, Cargill, Cummens et al ..... April 21, 2017
Alliance for Industrial Efficiency ..... April 21, 2017
Dakota Electric Association (DEA) ..... April 21, 2017
Minnesota Power (MP) ..... April 21, 2017
MnSEIA (revised) ..... April 24, 2017
Metropolitan Council ..... May 10, 2017
OTP Addendum to initial filing ..... May 12, 2017
MCA/FE ..... May 15, 2017
Affected Solar Community ..... May 15, 2017
Xcel Energy (Xcel) ..... May 15, 2017
All Energy Solar ..... May 15, 2017

Sundial Solar ..... May 15, 2017
Department of Commerce (DOC) ..... May 15, 2017
Energy Resources Center (ERC) ..... May 15, 2017
MnSEIA ..... May 15, 2017
Novel Energy Solutions ..... May 15, 2017
Minnesota Power (MP) ..... May 15, 2017
Renewable Energy Services ..... May 15, 2017
Dakota Electric Association DEA) ..... May 15, 2017
City of Minneapolis ..... May 19, 2017
Otter Tail Power Company (OTP) Public and Non-Public ..... June 9, 2017
Xcel Energy (Xcel) ..... July 27, 2017

Xcel compliance filing (in Docket No. 13-315) ..... May 19, 2017

The attached materials are workpapers of the Commission Staff. They are intended for use by the Public Utilities Commission and are based upon information already in the record unless noted otherwise.

This document can be made available in alternative formats (i.e., large print or audio) by calling (651) 296-0406 (voice). Persons with hearing loss or speech disabilities may call us through their preferred Telecommunications Relay Service.

Table of Contents

Statement of the Issue

Should the Commission approve, reject or approve with modification the standby service tariffs filed by Xcel, MP, OTP and DEA?

Should the Commission delay approval of any of the utility-proposed tariffs and require additional processes in order to make further revisions, including further standardization, to the utility-proposed standby service tariffs?

Should the Commission approve Xcel's Solar PV Capacity Credit Rider, including the current level of the solar capacity credit?

Introduction

Standby service is a set of electric utility products for customers with on-site, non-emergency generation. These services may include backup power for unplanned outages, maintenance power during scheduled generator service and supplemental power for customers whose on-site generation does not meet all of their electrical needs. Standby tariffs establish the rates, terms, and conditions of service through which a self-generating customer secures ongoing utility service when needed.

In November 2015, the Commission ordered the four rate-regulated utilities to file individual proposals for updated standby service tariffs that reflected the comments and discussion to date in the standby service docket. In its November 19, 2015 Order,[1] the Commission concluded that a productive alternative to a generic proceeding would be to order the four rate-regulated utilities to file individual proposals for tariffs. Accordingly, on May 19, 2016, each utility filed a proposed tariff. In addition to its standby tariff, Xcel filed a separate proposal for a solar capacity credit rider.

In the fall of 2016, the Commission received comments on the four proposals. In January 2017, in an effort to better understand these proposals, the Department sponsored two workshops and parties issued a series of information requests. In the course of this information exchange, a better understanding was reached concerning the structure and application of the proposed tariffs.

Due to the changing information set surrounding this process, on February 17, 2017 the Commission issued a notice asking parties to provide updated positions. This briefing paper is based primarily on these updated comments. It reviews the four utility proposals for standby service tariffs, considers the issue of whether a single, standardized template can be used by all four utilities and evaluates Xcel's proposal for a solar capacity credit rider.

Background

In its November 19, 2015 Order, the Commission acknowledged several years of written comments by and discussions among the parties in the generic proceeding. After a thorough review of the record to date, the Commission decided not to pursue the generic proceeding and ordered the rate-regulated utilities to file updated standby service tariffs by May 19, 2016. It concluded that an "iterative approach—requiring the rate-regulated utilities to file updated tariffs that have been informed by the discussion so far" was the best way to move forward. The November 19, 2015 Order stated:

[1] *Order Requiring Tariff Filings*, in Docket No. E-999/CI-15-115, issued November 19, 2015.

> Having reviewed the comments of the participants, the work already done by the Department and stakeholders, and the further input provided at the Commission meeting, the Commission concludes that the most effective way to further develop the issues surrounding standby service is to require the rate-regulated utilities to file updated standby service tariffs. (p. 3)
>
> ……..
>
> At the Commission meeting, the rate-regulated utilities and the Department agreed that a productive alternative to a generic proceeding would be to require rate-regulated utilities to file updated standby service tariffs. Representatives of municipal and cooperative utilities concurred that rate-regulated utility tariff filings could guide their own deliberations over developing standby service tariffs. Representations by the rate-regulated utilities at the meeting also indicated very few customers currently receive service under these tariffs—only Xcel indicated that it has more than one current standby service customer.
>
> With these details in mind, the Commission agrees that requiring updated tariffs is another way to continue developing these issues and prefers it in this case over seeking authority to incur additional professional costs. Because there is another path forward that will be both productive and less burdensome on the Department, the Commission will not request that the Department seek authorization under Minn. Stat. § 216B.62, subd. 8.
>
> Substantial discussion and development of standby-service-related issues has taken place, facilitated by the Department–stakeholder discussions in 2014 and the comments in this proceeding. An iterative approach—requiring the utilities to file updated standby service tariffs that have been informed by the discussion so far—will provide a concrete demonstration of the progress that has already been made. The filings will be subject to public comment and will facilitate clearer focus on what areas of disagreement, potential improvement, and opportunities for standardization still remain. (pp. 3-4)

On May 19, 2016, each of the four rate-regulated utilities filed a proposal for standby service. As noted, Xcel also filed a separate Solar PV Capacity Credit (SCC) Rider. Interested parties then filed initial and reply comments and issued information requests to the utilities. On both December 13, 2016 and January 25, 2017, the Department convened workshops to clarify issues in the docket to ensure a common understanding of the utility standby service rate proposals and Xcel's proposal for a solar capacity credit rider.

On February 17, 2017, the Commission issued a notice seeking comments in order to allow the parties to provide the Commission with final updates and to clarify their positions. The February 17 notice recognized that as a result of the DOC workshops and the additional information entering the record (through information requests), an increased understanding of how the utility-proposed tariffs apply was achieved.

Interested parties updated prior comments and proposed specific recommendations; staff considers the updated comments to have overtaken prior comments. In addition, there were changes to parties' positions between the comments filed on April 21, 2017 and those filed on May 15, 2017, especially as they related to Xcel's solar capacity credit proposal. Parties acknowledged that some of the new concepts and issues raised may need further record development and be reserved for future

consideration by the Commission. Other important decisions can be made now to move standby service tariffs and Xcel's solar capacity credit forward.

These briefing papers are presented in two parts: (1) a review of the four utility proposals for standby service tariffs and related issues, and (2) a review of Xcel's proposal for a Solar PV Capacity Credit Rider.

Utility proposals for revised standby service tariffs

Introduction to standby service tariffs

In response to the Commission's November 19, 2015 Order, each of the four rate-regulated electric utilities filed updated standby service tariffs. In its Order, the Commission noted that substantial discussion and development of standby service-related issues had taken place, facilitated by the DOC, stakeholder meetings, and comments in the docket. What follows is a brief summary of the revised tariffs, followed by a summary of the comments filed by parties in response to the Commission's February 17, 2017 notice asking parties to bring forward and update all comments in the record thusfar.

Xcel Energy's (Xcel's) revised Standby Service Rider

Xcel's proposal for a revised Standby Service Rider

On May 19, 2016, Xcel petitioned the Commission for approval of its revised Standby Service Rider.[2] Because distributed solar has different attributes than traditional on-site generation,[3] the Company separated its current standby service rider into two types of service—standby service (the Standby Service Rider) and a separate service for solar-generation customers and new wind (the Solar PV Capacity Credit Rider). Xcel is seeking approval of both riders. The Company currently provides standby service under the existing standby service rider to 30 customers, of which 23 have on-site solar PV generators. Once the proposed Solar PV Capacity Credit (SCC) Rider is approved, customers with on-site solar will receive a capacity credit for on-peak solar capacity under the Rider.

Xcel argued that the Company's two Riders balance the goals set forth in the proceeding, including providing reliable electrical service, making the terms of standby service transparent and flexible, promoting economically efficient consumption, reflecting appropriate costs and benefits through cost causality, and overall simplification.[4] In Xcel's petition requesting approval of its Standby Service Rider, the Company provided Table 4, which demonstrates how Xcel's revised tariff addresses each of the DOC's recommendations for a standby service tariff.[5]

Xcel summarized the purpose of standby service as follows:

> Standby is a utility service that ensures customers using their own generation have a reliable supply of energy. The customer's generation provides a portion of the supply requirements

[2] Xcel Tariff Sheets, Section No. 5, Sheet No. 101-106. The red-lined version of both proposed Riders is attached to Xcel's May 19, 2016 filing.
[3] Distributed solar has an intermittent generation profile and relatively low capacity factors when compared to the more traditional on-site generation.
[4] Xcel, November 9, 2016, p. 1.
[5] Xcel, May 19, 2016, p. 13.

> for their own load, up to their generating capability, and the utility provides backup to the customer's generation. Supply for the customer's load that is greater than the customer's generation capability (residual load), and generation, transmission and distribution capability for the customer's full load is also provided by the utility. As a resource to provide backup in a standby relationship, the utility maintains generation reserves, as well as transmission and distribution facilities, to serve customers receiving standby service.[6]

The Company further explained:

> Standby service tariffs are generally intended to accurately price the fixed cost of reserve generation and transmission capacity, and full distribution capacity with a mechanism that adjusts charges based on the extent that the customer requires backup service. In essence, as a customer increasingly requires the utility to replace their generation supply, the cost to the utility increases for providing that service and correspondingly, standby service charges to the customer should increase.[7]

Xcel revised its current standby rider by replacing the annual grace hours provision with a provision for a 20-hour monthly exemption[8] during peak hours, using a daily peak period of 1:00-7:00 p.m. It also proposed to revise the current standby service to replace the present monthly demand usage charge for standby capacity with a peak period kWh-based surcharge.[9]

Xcel noted that a primary distinction for more continuously operated (non-intermittent) customer generation is that it results in no billable demand quantities during many months without the use of a standby service reservation demand charge. To address this issue Xcel designed a new peak period kWh-based surcharge to replace the monthly base rate demand charge for standby capacity. The energy surcharge (Excess Standby Energy Usage Charge) is applied to standby backup energy usage that occurs on peak and exceeds a monthly kWh exemption quantity.[10] The energy based surcharge is applied to kWh standby usage that exceeds contracted standby service kW times 20 hours.[11] The energy-based approach provides a more focused price signal that functions similarly to a daily as-used demand charge for used backup capacity. Xcel believes that the proposed approach provides a smoother and more proportional transition for customers from no use of standby backup energy to complete use of standby backup energy during each month. It also simplifies billing by using the same standby reservation demand charge billing every month of the year, and eliminating the requirement to accumulate the present 964 annual grace hours throughout the year.

The Excess Standby Energy Usage Charge is a replacement for the present monthly demand charge for standby capacity used. Xcel explained that by replacing the standby usage demand charge with an excess peak period energy usage charge, and replacing annual grace hours with monthly exempt peak

---

[6] Xcel, May 19, 2016, p. 5.
[7] Xcel, May 19, 2016, p. 6.
[8] The current grace hours provision uses 964 hours measured on an annual basis with no time-of-use differentiation. That is an average of 80 hours each month—the basis for the proposed 20 hours per month with a six-hour (25% of daily hours) daily peak period.
[9] Xcel explained that focusing on a daily peak window of time minimizes complexity, encourages efficient system operations, and provides relatively consistent treatment for traditional standby with the terms of the new Solar PV Capacity Credit Rider.
[10] Xcel, May 19, 2016, p. 16.
[11] A standby service agreement is required to define the customer contract capacity level (Section 6, Tariff Sheet 10).

period kWh, its standby service will more clearly and equitably recover the costs of providing standby service.[12]

In sum, Xcel argued that its standby service proposal is cost-based and continues to recognize unavoidable full distribution costs and a reserve share of generation and transmission costs for customers with self-generation. Additionally, a variable usage charge is proposed for the actual use of standby backup service, following an exempt period, such that the customer pays the regular service rate when their generator is completely out of service.[13]

Xcel proposed to implement and file its revised standby service tariff 90 days from the date of a Commission order approving it in order to allow for a smooth customer transition. Customers currently taking service under the Company's existing tariff and/or Standby Agreement would be notified by mail and become subject to the newly tariffed terms once in effect.

Xcel emphasized that the proposed rate design revisions include significant structural changes. Recognizing that there could be unintended consequences, Xcel recommended an evaluation and review process. This could be coordinated with the one-year compliance requirement in the docket in which the solar capacity credit was initially set.[14]

Parties' comments on Xcel's standby service rider

In response to the Commission's February 17, 2017 notice seeking comments on the specific utility-proposed tariffs, parties raised three main issues regarding Xcel's proposed tariff: (1) whether there should be a grace period with exempted hours, (2) how to determine the actual standby usage level,[15] and (3) the request by Flint Hill Resources for a separate CHP tariff for larger CHP projects.

Parties' comments on Xcel's proposal to decrease but not eliminate grace period hours

The DOC recommended that the Commission require Xcel to completely eliminate the grace period exempt hours and to recalculate the standby rider rates without any exempt hours.[16] According to the DOC, total elimination of the exempt hours would encourage reduced peak standby usage, reduce billing complexity and be more consistent with the other utilities' standby rates.[17] The DOC proposed

[12] Xcel May 19, 2016, p. 16.
[13] Xcel, May 19, 2016, p. 16.
[14] Order Setting *Final Solar Photovoltaic Standby Service Capacity Credit, Requiring Updates, and Requiring Compliance Filing*, in Docket No. E-002/M-13-315, issued May 19, 2014, Ordering Point 4.
[15] In comments filed May 15, 2017, MCA/FE argued that neither Xcel's demand charges nor its energy charges pass utility off-peak or seasonal cost differentials to the customer; it maintained that providing these cost differentials would send fairer and more accurate price signals to customers. Since MCA/FE raised this issue as part of reply comments, and Xcel was not able to respond, the issue cannot be fully briefed here. The Commission may wish to ask Xcel to respond to the issue at the meeting. The standby reservation demand charge is not seasonal because the charge is mostly comprised of distribution costs, which are not seasonal. The standby usage rates are seasonally differentiated to correspond to the seasonal demand charges in standard tariffs and the six-hour peak period used for the proposed standby usage energy charge does provide a focused time-of-use price signal. In addition, the DOC raised the issue of requiring Xcel to propose a monthly contract schedule for maximum load threshold and generation capacity. (DOC, May 15, 2017, p. 5)
[16] As noted, Xcel's current proposal includes a monthly 20 hour grace period during the on-peak period from 1:00 p.m. to 7:00 p.m. Usage occurring during outages covered by the grace period would be exempted from application of the Excess Standby Energy Usage Charge. The grace period proposal allows for generator outages at the same rate as Xcel's forced outage rate.
[17] Although elimination of Standby Rider application to solar DG facilities resolves many of the concerns about the application of the grace period, the DOC continued to question whether the grace period should remain. It also argued

that Xcel be required to recalculate the Excess Standby Energy Usage Charge to incorporate the Company's forced outage rate (FOR) absent any exempt hours.

In comments filed May 15, 2017, the DOC provided Xcel's response to IR #39, in which Xcel recalculated the Excess Standby Energy Usage Charge absent exempt hours. IR #39 indicates that eliminating the exempt hours reduces this charge. Based on this, the DOC recommended the elimination of any provision allowing for exempted hours or a grace period.[18]

In comments filed May 15, 2017, MCA/FE argued that the concept of a grace period with exempt hours may provide cost savings to some standby customers in some situations but that Xcel has not provided evidence that exempt hours are based on an underlying reduction in the cost of service. MCA/FE questioned whether: (1) outages of less than 20 hours place such minimal demand on utility resources that a demand charge is unwarranted or not cost-effective, (2) costs from which customers are being exempted are costs being paid in higher charges elsewhere or by other customers, (3) the provision of grace hours is inequitable i.e. can 20 hours of exempt standby demand charges be either too much or too little for any given customer, and (4) exempt hours mask efficient price signals.[19] In earlier comments, the Energy Resource Center (ERC) commented that standby customers should not be required to pay for a grace period allotment that might go unused and that the use of a grace period distorts the cost of providing peak period standby capacity to standby customers.[20]

Xcel's response to parties' comments on the exempt hours provision

Xcel explained that under its current standby service rider it provides an annual grace period of 964 hours during which standby customers are exempt from the base tariff demand rate and instead pay a lower Reservation Demand Rate for their contract standby capacity. Following the use of the annual grace hours by customers, the billing of contract standby capacity is changed to the higher base tariff demand rate for the remainder of the annual contract period.

Under the proposed rider, however, the annual grace period is converted to a monthly on-peak exempt period of 20 hours (calculated as: 964/12 months x 6 on-peak hours/24 daily hours). Following the use of the monthly exempt hours, standby usage is billed at a proposed standby usage rate per kWh that is based on the difference between standard and standby demand rates.

Xcel responded to parties that the proposal for the 20-hour monthly exemption from the Excess Standby Energy Usage Charge is based on both theoretical and practical considerations.[21] It noted

---

that outages during peak periods should be discouraged and that permitting a grace period of 20 hours during a month reduces the incentive to avoid such outages at least during those 20 hours. It argued the grace period provision increases the complexity of billing and is not a component included in other utilities' standby rates. (See DOC comments, April 21, 2017, p. 6.)

[18] DOC, May 15, 2017, pp. 3-4.

[19] MCA/FE, May 15, 2017, p. 7.

[20] ERC, August 19, 2016, p. 6. Minnesota Energy Storage Association (MESA) also expressed concern with the grace hours provision. Neither of these parties provided updated comments on this issue for consideration.

[21] Xcel's standby service also includes a customer grace energy use period. The purpose of the grace period is to allow for a reasonable level of customer-sited generation outage prior to incurring standby service usage charges. The grace period structure credits customer generation with a utility-based forced outage rate for backup service before regular General Service demand charges start to replace the lower standby reservation demand charges. Company generation on average is available to service customer load 89 percent of the time, and 11 percent of the time is unavailable for either scheduled or forced outages. Applying equal treatment for customer generation receiving backup generation supply from the Company provides the customer with an 11 percent energy supply from the Company before the charges in the Standby

that all customers pay the base energy charge for any standby usage, with the Excess Standby Energy Usage Charge serving as a graduated demand charge for actual standby usage that exceeds a standard utility plant outage rate. Xcel defended its exempt hours provision in four ways. First, at the relatively low outage rate represented by the proposed 20 monthly hours, the expected diversity of capacity requirements has a minimal expected cost. Second, a realistic expectation of all customer generation is that reductions in its availability throughout the year will not allow it to avoid all exempt hours. Third, as a direct replacement of existing annual grace hours, the proposed exempt monthly hours provision allows a smoother transition for the outages of existing customers.[22] Xcel argued that it will be difficult for customers to transition from a monthly exemption of 100 hours to none, as proposed by the DOC. Lastly, Xcel noted that if grace hours were totally eliminated the proposed rate would need to be restructured.

In sum, Xcel maintained that the exempt hours provision allows a reasonable cushion level of reduced customer generation before usage charges begin to apply. The "cushion" is based on a utility-based forced outage rate of 11 percent to provide customers with equal treatment.

In comments filed May 15, 2017, Xcel noted that although a revision to remove a grace period might further simplify the tariff and enhance the incentive for customers to avoid generation outages, the provision should be retained to provide rate continuity for customers on the Standby Service Rider. It also addresses customer concerns with generator output variations and is consistent with the inclusion of a share of generation and transmission costs in the Reservation Demand Charge.[23]

Xcel also noted that parties' concerns with the grace period apply mainly to solar customers on the current Standby Service Rider, not necessarily to customers that would be taking service under the proposed revised Standby Service Rider. Xcel noted that the grace period was of particular concern for solar generators because of the intermittent nature of their solar generation and the fact that the grace period hours were typically used within 1-2 months.

Staff comments on Xcel's proposal to decrease but not eliminate the grace period and exempt hours

As part of its revisions to the current Standby Service Rider, Xcel simplified and limited the application of the exempt hour provision by significantly reducing the total monthly number of exempted hours and removing the grace hours provision for intermittent customers. Among other reasons for keeping the provision, Xcel explained that customers understand and are familiar with and to some extent expect it as a way to cushion the measurement of standby usage. The Commission may wish to consider allowing Xcel to phase out the provision over some period of time rather than fully eliminating it.

Parties' comments on Xcel's method for determining the level of standby usage

MCA/FE noted that Xcel's proposed standby service rider ties standby usage to generator output instead of overall demand for the customer. It argued that this method of assessing standby usage prevents customers from self-supplying standby power through load reductions, backup generation resources and other approaches. Under the proposed rider, Xcel assesses standby charges based on

Service Rider begin to increase. This 11 percent of energy supply results in 964 hours of grace period energy (8760 hours in a year times 11 percent). See Xcel Petition, May 19, 2016, p. 7.

[22] Xcel, November 9, 2016, p. 9.

[23] Xcel, May 15, 2017, p. 1.

the differential demand between a generator's contractual output (i.e. nameplate capacity) and its actual output regardless of the level of demand incurred on Xcel's system. MCA/FE argued this can lead to situations in which a customer must pay standby charges even if they are not drawing any power from Xcel, because their generator is not operating at its contractual level.[24]

MCA/FE argued that standby tariffs should recover the costs to provide generation and related infrastructure to serve the increased demand created from a customer's generator outage. If this increased demand never occurs, through various standby self-supply strategies, then no additional costs are imposed on the utility, and standby charges are not justified.[25] MCA/FE recommended that Xcel be required to revise its definition of standby usage to allow for standby self-supply and create a demand cap above which standby usage charges are assessed. MCA/FE further proposed that unless this cap is exceeded, no standby charges should be assessed, even if the customer's generator was not operational.

The DOC agreed with MCA/FE that customers should not be charged for standby service when they use less than the full contracted generator capacity amount, regardless of the customer's total demand placed on Xcel's system. The DOC noted that MP, OTP and utilities in other states charge for standby based on customer demand that exceeds a contracted load threshold but not when they use less than the contracted amount. Like MCA/FE, the DOC recommended that the Commission require Xcel to restructure its standby rate so that a customer contract defines a maximum load threshold for application of the base tariff, above which the customer is charged for standby service up to the generator capacity. The DOC recommended that the Commission consider requiring Xcel to propose a monthly contract schedule for maximum load threshold and generator capacity.[26]

The ERC filed an alternative method for determining standby usage charges in the last round of reply comments.[27] It also recommended that the Commission require Xcel to incorporate the definition and structure of standby usage used by MP.[28]

Xcel's response to comments on the method for determining the level of standby usage

In response to parties' concerns regarding the method used to define actual standby service usage, Xcel explained that the proposed tariff separates total site load into two separate services. First, the Reservation Demand charge for standby service includes only a reserve margin amount of generation and transmission capacity costs. Second, as actual standby usage occurs above the exempt level, the

[24] MCA/FE, April 21, 2017, p. 12.
[25] MCA/FE, April 21, 2017, p. 12.
[26] DOC, May 15, 2017, p. 4-5.
[27] ERC, May 15, 2017. In earlier comments, prior to the Commission's February 17, 2017 notice, ERC questioned: (1) the definition of standby usage, (2) whether there should be a reservation charge for both unscheduled and scheduled standby service, (3) the use of a grace period, and (4) whether standby service customers are being charged higher costs for periods of Company system peak hours in which the Company has insufficient accredited capacity.
[28] Under ERC's proposal, the Nominated Standard Service would be the maximum amount of demand for Standard Service and would set the peak demand ratchet in Xcel Rates A14, A15, A17 and A19. Standby usage would be defined as the capacity above the Nominated Standard Service up to the nameplate capacity of the on-site generator (alternately up to the Contract Standby Capacity). Standby usage charges would only be assessed during times when the customer exceeds the capacity ceiling of the Nominated Standard Service. Excess standard service demand utilized in excess of the aggregation of the customer's Nominated Standby Service and Contract Standby Capacity would be billed on the customer's standard rate schedule and subsequently added to create a new ceiling for the nominated standard service. In keeping with Xcel's proposed Excess Standby Energy Usage Charge per kWh, all standby capacity could be multiplied by the number of hours the customer is taking standby service and then multiplied by the Excess Energy Charge to arrive at a standby usage charge.

Excess Standby Energy Usage Charge works to gradually recover the remaining generation and transmission capacity costs up to, but not in excess of, the standard demand charge level. The measured actual use of standby service occurs independently from corresponding reductions in total customer site load. The design of standby service and the definition of actual standby usage is based on the expectation that customer generation is continuously operated at its contract capacity level. When customer generation operates below the contract capacity level, the customer is actually using reserved backup capacity. Any variation in the total site load of a standby service customer is comparable to standard service load variations by a non-standby service customer without their own generation. Xcel argued that a "mix and match" approach that would attribute and assign load variations in standard service to standby service is not analytically sound or appropriate. For this reason, the proposed Standby Service Rider defines actual standby usage as occurring when customer generation is not operating or is operating below the contracted standby capacity level.

As noted above, Xcel explained that changing the basis for measuring the standby usage quantity would require a corresponding change to the standby usage rate.[29] In general it is necessary to recognize that the usage quantity measurement is designed to be consistent with the applicable rate. However, in this case, Xcel noted that parties have proposed to modify the usage quantity measurement (actual standby usage). This could not be done without revising the applicable rate. The standby usage provision is designed to produce charges that increase with reduced customer generation, such that at the limit, billing with zero customer generation is the same as the regular service tariff.

Staff comments on Xcel's method of determining the level of standby usage

Staff believes the Commission should take note that changing the basis for measuring the standby usage quantity as suggested by MCA/FE, ERC and DOC will require a corresponding change to the Excess Standby Energy Usage Charge, and to the fundamental design of the proposed new rate structure. For this reason, before adopting these changes, the Commission may wish to hear from Xcel and discuss the issue with parties. Staff notes that the revisions suggested by MCA/FE, DOC or ERC are significant and would require changes in the design of the service as proposed by Xcel; the redesigned tariff would also need to be refiled for further analysis and comment.

Parties' comments on the Excess Standby Usage Charge and Xcel's response

Minnesota Energy Storage Alliance (MESA) initially noted its concern that the proposed Excess Standby Energy Usage Charge might be an extra charge with no corresponding reduction in customer costs.[30] However, it did not update its comments for Commission consideration in response to the February 17, 2017 notice.

Xcel responded that the proposed Excess Standby Energy Usage Charge is not a new extra charge but a replacement for the existing Demand Charge for used standby capacity. The designed purpose of the present and proposed charges is to provide a graduated transition for lower cost standby service to regular firm service as customer generation is reduced to zero. Both provisions serve the same purpose, although the proposed provision is simpler, more understandable and economically efficient since it focuses on peak period hours. Also, when customers respond to the more economically efficient price signal, the benefit is not retained by the Company as suggested. Xcel noted that, as

[29] Xcel, May 15, 2017, p. 6.
[30] MESA, August 19, 2016, p. 5.

with all economically efficient price signals, when customers respond they benefit. In addition, the associated cost reductions benefit all customers.[31]

Xcel's response to MESA regarding its request for additional incentives for storage

MESA urged the Company to include mechanisms to promote storage in its standby service modification proposal.[32] Xcel responded that the application of technologies related to energy storage by customers is still an emerging area and system benefits from storage are unclear at this time. Xcel commented that there is more to learn about this new field and the Company does not believe this issue is sufficiently developed in the record to consider it as part of this proceeding.[33]

Diversity of load and actual cost of service

Comments by a group of interested parties on diversity of load and actual cost of service

On April 21, 2017, a group of manufacturers, developers, and institutions[34] filed comments in the docket noting that excessive standby rates harm competitiveness and discourage companies from developing CHP and waste heat to power (WHP) projects in Minnesota. They argued that standby tariffs that are based on the unlikely assumption that utilities must maintain excess utility capacity equivalent to a CHP facility's generation capacity in case of an unanticipated outage, do not consider the diversity of customer load and the actual cost of service imposed by partial use customers who generate their own power 95% of the time.

Xcel's response on the issue of diversity of load and actual cost of service

In response, Xcel argued that its Standby Service Rider is not deficient and is designed to consider the diversity of customer load and the actual cost of service imposed by 'partial use' customers. Xcel explained that its Standby Service capacity charges are directly linked to serving the full diversity of customer load on the Company's system and that the service is designed to recover the Company's costs to stand by for customers who self-generate.[35]

Xcel's response to University of Minnesota

The University of Minnesota proposed that the Company's proposed Standby Service Rider be modified to reflect monthly nominations made annually.[36] Xcel agreed and noted that the University's suggestion was a constructive modification that increases the precision of the rate without adding significantly more complexity. Xcel supported this recommendation and refiled its proposed tariff to reflect the revision.[37]

---

[31] Xcel, November 9, 2016, p. 8-9.
[32] MESA, August 19, 2016, p. 2.
[33] Xcel, November 9, 2016, p. 12.
[34] The group included: Ameresco, Cargill, Cummins, Ecolab, Ever-Green Energy, Minnesota Forest Industries, Schneider Electric, and Veolia North America.
[35] Xcel, May 15, 2017, p. 3.
[36] University of Minnesota, April 21, 2107. The U of M suggested: (1) monthly nominations, (2) capacity credits based on kWh not kW, and (3) review of tariffs in light of changes in technology.
[37] Xcel filed this revision on May 15, 2017 (Attachment A). The revision indicates that contracted standby capacity may be different for summer or winter seasons or by month.

Staff comments on Xcel's proposed Standby Service Rider

The Commission should note that it could decide to make some additional modifications to Xcel's proposed tariff but that the rider is complex and changes to one part may require changes to other parts of the structure.

Xcel has requested 90 days to notify customers taking service under the current rider of how changes would affect these customers. If the Commission decides to make additional changes beyond those proposed, it may wish to allow Xcel more time to notify customers or possibly allow Xcel to phase in changes over a longer period of one to two years.

As noted, the Commission may also wish to allow Xcel to respond to certain issues at the meeting, since some issues were raised for the first time in final reply comments.

Flint Hill Resources (FHR)[38] request for a separate Xcel standby service rider tailored for Combined Heat and Power (CHP) projects 10 MW and greater

FHR is currently constructing a 50 MW CHP project that will begin operation in 2018. It includes a gas turbine (with output that will vary by up to 10 MW depending on ambient air temperature changes), a heat recovery steam generator, and a steam turbine with output that will vary depending on changes in use of heat recovered and steam generated for use at the refinery versus for power generation.[39]

FHR filed comments on the potential effects of Xcel's proposed Standby Service Rider on its future CHP project. It recommended that Xcel be required to develop and file a separate standby tariff tailored to customers with larger self-generation projects (10 MW or greater), such as FHR's CHP project.

FHR provided information about its CHP project to demonstrate the complexity of CHP projects and other similar large self-generation projects. It recommended that the Commission order Xcel to propose a separate standby service tariff for CHP facilities with generating capacity in excess of 10 MW that would provide the clarity and specificity needed for large CHP projects located on-site at large industrial facilities. It recommended certain specific concepts be incorporated into the new tariff, and recommended additional proceedings to develop the record for a CHP standby service tariff and a timeline for such proceedings.[40]

With the completion of the project, FHR will typically require between 77 MW and 93 MW of Supplementary Power.[41] The project facility will operate around-the-clock, with a high load factor. It is projecting significant load growth and will require the ability to increase Supplementary Power requirements and adjust the amount of Scheduled and Unscheduled Maintenance under the Standby Service Rider. Planned maintenance on the CHP facility will be performed during the biennial

[38] Flint Hills Resources, LP, and Flint Hills Resource Pine Bend, LLC, collectively "FHR." FHR operates the Pine Bend oil refinery in Rosemount. The refinery operates around the clock with a peak power demand of approximately 131 MW of firm capacity at a greater than 90% average monthly load factor. It currently takes transmission transformed service on Xcel's Rate A15 tariff and requires a steady supply of firm (non-interruptible) power.

[39] FHR, April 21, 2017, p. 3.

[40] FHR, April 21, 2017, p. 2.

[41] FHR noted that Minn. R. 7835.0100, subpart 21, defines "supplementary power" as "electric energy or capacity supplied by the utility which is regularly used by a qualifying facility in addition to that which the facility generates itself. This definition largely parallels the federal definition in 18 CFR §292.101.

turndowns of the refinery when site power use is lower than usual. These turndowns occur during the non-summer months and can be coordinated with Xcel to occur during low cost periods. FHR will also need to purchase Unscheduled Maintenance, but rarely.[42]

FHR argued that its needs for both Supplementary and Standby Power are well-defined and clearly different from Xcel's smaller standby customers and customers that operate some form of renewable on-site generation. These differences include the ability to plan for maintenance outages, the anticipated duration of maintenance outages, the predictability of variation in output, the effect of different grace period structures, and the ability to plan for and anticipate changes in load.[43]

FHR recommended 10 MW as an appropriate size threshold for a new CHP-specific rider because customer generation projects above this size have historically been treated differently in Minnesota than smaller (under 10 MW) distributed generation projects (e.g. Xcel's distributed generation interconnection tariff). Xcel has already used the 10 MW threshold for differentiating terms related to scheduled maintenance in the proposed Standby Service Rider.[44]

FHR proposed a separate standby service rider tailored for CHP projects based on the proposed rider with five modifications: (1) proper application of the definition of standby service from the Minnesota Administrative Rules,[45] (2) clarification that customers can choose multiple types of standby services, (3) clarification to avoid duplicative reservation charges for customers who choose multiple types of standby service, (4) reversion to a grace period concept more in keeping with the existing Standby Rider, and (5) removal of unreasonable limitations on the duration of Scheduled Maintenance service.[46]

FHR noted there are significant issues to be addressed in the development of a separate CHP standby rider and further record development is necessary, and that it is prepared to work with Xcel and other interested parties to develop a customized tariff. It requested that the Commission: (1) order Xcel to file a CHP standby rider within 60 days of the Commission's order in this matter consistent with the concepts described by FHR in its comments filed April 21, 2017, (2) establish comment and reply periods to solicit input on Xcel's proposed CHP Standby Rider, and (3) establish time periods for comments that will allow for a final decision on the new rider that would allow it to be implemented by the end of 2017.

DOC's response to the FHR proposal to develop a separate standby service rider for CHP projects 10 MW and greater

The DOC commented that the scope of the current proceeding is to focus on distributed generation. It referenced the Commission's November 19, 2016 Order, which states:

> Utilities charge "standby" rates to certain distributed generation facilities to recover costs incurred to make electricity service available to those facilities. Standby service makes electricity available to generating facilities during planned and unplanned outages, among other needs.[47]

[42] FHR, April 21, 2017, p. 4.
[43] FHR, April 21, 2017, p. 5.
[44] FHR, April 21, 2017, pp. 5-6.
[45] Minnesota Rules 7835.0100, subp. 21.
[46] FHR explained each of these proposed changes in its April 21, 2017 comments, pp. 6-13.
[47] *Order Requiring Tariff Filings*, in Docket No. E-999/CI-15-115, issued November 19, 2015, p. 2.

The DOC also noted that Minn. Stat. § 216B.164, subd. 2a(h) defines distributed generation to mean a facility with a capacity of 10 MW or less. The DOC concluded that consideration of standby service to facilities greater than 10 MW would need to be undertaken separately from the current proceeding in order to reflect the unique requirements of the larger facilities and the effect on the utility's system and costs involved.

Xcel's response to the FHR proposal to develop a separate standby service rider for CHP projects 10 MW and greater

Xcel objected to the fact that FHR introduced its proposal for a new rider for larger CHP customers at the close of a long process. It argued parties need more time to fully evaluate the proposal and that the new submission is not appropriate for consideration at this time. However, Xcel also indicated that the Company is willing to work with FHR and other parties, as part of a separate proceeding, to consider the issues raised. In addition, Xcel clarified what it suggested were misunderstandings on the part of FHR.

According to Xcel, FHR's comments reflect a misunderstanding of the Company's present and proposed Standby Service Rider. For example, the three different types of Reservation Demand Charges are exclusively applied, meaning only one type can be applied to a customer rather than the duplicative process assumed by FHR. Additionally, Xcel noted that the proposed Standby Service Rider is not available to new renewable generation customers as suggested by FHR.[48]

Xcel argued that FHR's concern with the measurement of standby usage, including its application to proposed exempt hours for the proposed Excess Standby Energy Usage Charge, needs to recognize that the usage quantity measurement is designed to be consistent with the applicable rate. The standby usage provision is designed to produce charges that increase with reduced customer generation, such that at the limit, billing with zero customer generation is the same as the regular service tariff. Changing the basis for measuring the standby usage quantity would require a corresponding change to the standby usage rate.[49]

Xcel argued that the primary basis for FHR's interest in a new, separate and specialized tariff appears to be a concern that FHR's planned CHP system will have reduced capacity during the hottest summer days. Xcel noted that this is exactly when customer generation is most needed and valuable to meet system peak load requirements. Rather than justifying a specialized tariff, Xcel argued that this weather-based generation capacity profile is an endorsement of the Company's proposed standby usage charge, which efficiently focuses on peak time generation performance. Further, Xcel argued that the Standby Service Rider works in tandem with standard tariffs that are not differentiated at the 10 MW or any other load level. A 10 MW or other load level may not be a justification for a different standby service rate design.[50]

Xcel noted that FHR also expressed a concern with the current scheduled maintenance service limit of six weeks every year. According to Xcel, this maintenance service limit provides an exemption from standby usage charges. Although the Company does not agree that there is no foundation for

[48] Xcel, May 15, 2017, p. 5.
[49] Xcel, May 15, 2017, pp. 5-6.
[50] Xcel, May 15, 2017, p. 5-6.

this limitation, it indicated that revising the limit from six weeks to eight weeks would be a reasonable response to FHR's concern.[51]

Xcel indicated that it has continued to discuss the issue of a separate CHP standby service with FHR. However, it believes that FHR does not fully understand the Company's proposed Rider. Based on FHR's comments, Xcel believes that the Commission cannot conclude that change is necessary at this time. However, it is willing to work with FHR to discuss further development of the concept.[52]

Staff comment on the FHR proposal to develop a separate standby service rider for CHP projects 10 MW and greater

Staff agrees with both Xcel and the DOC that the record is insufficiently developed to allow the Commission to adopt FHR's proposal for a separate tariff for larger CHP projects at this time. The proposal by FHR to require Xcel to develop and propose a separate standby service rider for CHP projects 10 MW and larger was introduced into the record for the first time on April 21, 2017.

However, the Commission may wish to require Xcel to work with FHR to address the issues raised and, if the parties can come to agreement, file a proposal for a separate rider, although Xcel appears to argue that a separate rider may not be merited. If the Commission decides to have this issue further briefed it may wish to assign it a new docket number.

Although they may not be sufficiently developed for a decision in this docket, FHR has raised important issues for consideration by Xcel and the Commission. These include its recommendations to clarify the terms and conditions of standby service for customers such as FHR, and further record development on these terms and conditions. As part of any discussions, parties should seek to resolve Xcel's concerns as well, including whether FHR misunderstood the application of Reservation Demand Charges to new renewable generation customers and their relation to the regular service tariff, among other issues.[53]

[51] Xcel, May 15, 2017, p. 6. Although Xcel did not file a proposed revision to its tariff to reflect this change, staff has included this revision as a possible decision option.
[52] Xcel, May 15, 2017, p. 5.
[53] Xcel, May 15, 2017, pp. 5-6.

Minnesota Power's (MP's) revised Standby Service Rider

MP's proposed Standby Service Rider

On May 19, 2016, MP filed an updated Standby Service Rider in compliance with the Commission's November 19, 2015 Order. The Company made several changes to its current Standby Service Rider.[54] The proposed Rider includes a monthly reservation fee, demand charges based on scheduled and unscheduled outages and an energy charge. MP is also seeking approval of minor revisions to its Electric Service Agreement for Distributed Generation/Standby Service to reflect the updates in the Standby Service Rider.[55] There are currently no customers taking service under the Rider.

MP's proposed Rider is designed for customers with distributed generation systems that have the ability to run on a continuous basis and to use the Company's electric service as temporary backup. Customers with intermittent distributed generation, such as solar PV, are provided back-up power through their standard base rate schedule.[56] The backup service provided under the proposed Rider is necessary when a customer relies on its distributed generation system to meet on-site electric load requirements and wants to avoid interruptions when its own system is not available. Backup service from the Company is required if the customer's distributed generation system is experiencing an outage or not generating at an historically normal level and the customer does not curtail its load requirements.[57]

MP indicated that in developing revisions to its current Rider, it relied on all the information in the docket, including all of the DOC's recommendations for designing standby rates. It noted that the proposed Rider meets the "best practices" proposed by the DOC and other stakeholders.[58] It then identified these best practices and explained how its proposed Rider addresses each, as described briefly below.

Generation, transmission, and distribution charges should be unbundled. MP calculated separate rates for generation, transmission, distribution primary, and distribution secondary service.[59] In order to simplify the Rider, these rate components were combined in the Standby Reservation Fee Rate.[60] The Rider design provides a balance between variable charges and contract demand that is reflected in the Standby Reservation Fee Rate calculation.[61]

---

[54] MP's current Standby Service Rider was approved by the Commission on January 27, 2014, in Docket No. E-015/M-13-770. However, as noted above, there are currently no customers taking service under the Rider.

[55] The revised Electric Service Agreement, with minor revisions, and the Standby Service Agreement, with no revisions, are provided as Exhibits C and E to MP's May 19, 2016 petition.

[56] The existing cogeneration or distributed generation riders under which these customers might take service include MP's Rider for Parallel Generation and Rider for Distributed Generation. Neither specifically reference back-up or maintenance service. However, they both reference the customer's standard rate schedule to which the rider is attached.

[57] MP, May 19, 2016. p. 13.

[58] MP, May 19, 2016, pp. 5-8.

[59] The unbundled cost components of the Reservation Fee Rate are shown in MP's May 19, 2016 filing, Exhibit B.

[60] The Standby Reservation Fee is applicable to all customers who elect service under the Standby Service Rider. The Fee compensates MP for having electric service available for delivery to meet the electric load requirements normally satisfied by the customer's distributed generation system. The Fee varies by service voltage levels and class of customer.

[61] For example, in months when the customer does not use any standby service, the Standby Reservation Fee Rate is applied to the customer's bills based on the availability of the customer's generator and the customer's elected kW of Reserved Standby Service through the Standby Service Agreement. This means that a customer who has reliable generation will avoid the majority of the fixed monthly Standby Reservation Fee.

Generation reservation demand charges should be based on the utility's cost and the forced outage rate (FOR) of customers' generators on the utility's system.[62] MP calculated the demand charge for backup power during scheduled outages using a daily (as-used) calculation. For backup power used during unscheduled outages, the standby rate reflects an on-peak and off-peak standby demand charge.

Higher-voltage delivery charges should recognize load diversity.[63] MP explained that the Standby Reservation Fee is based on the customer's generator forced outage rate (FOR) and quantity of generation being backed up by the Company. In months when standby service is not utilized, the billed amount is lower than the customer's standard rate schedule. This methodology recognizes that the standby service customer uses the shared utility infrastructure less than a full requirements customer for its standby load.

Standby rates should provide neither an incentive nor a disincentive for distributed generation. MP calculated its standby demand rates by using a cost-based revenue requirement calculation that ensures standby customers are neither provided an incentive nor a disincentive for distributed generation. It implemented incentives including pro-rated daily demand charges for scheduled outages that will incentivize customers to minimize outage length and coordinate outages with the utility when system generation requirements are low. Also, during scheduled outages, the rate design is based on the customer's standard rate schedule. Unscheduled Outage Demand and Energy Rates include on-peak and off-peak components.

Opportunities should be available for customer-generators to avoid charges when they do not take service. Customer-generators should also have the opportunity to buy backup power at market prices and avoid utility reservation charges for generation service. There should be an option for customer demand response or storage to mitigate all or a portion of backup charges, as well as for self-supply of reserves. Customers should be able to procure standby service from the open market. MP's proposed Standby Service Rider allows for opportunities for customers to avoid charges when service is not taken through a contract for standby capacity for an amount that fully covers the peak output of the customer's on-site generating units or a lower level of backup. This is done through the Standby Service Agreement, which allows the customer to designate a standby contract demand that is unique to its operations.[64]

MP described all the changes to its existing Rider in its May 19, 2016 Petition (see pp. 8-18). It explained that to be eligible, customers must take service under certain tariffs and enter into an Interconnection Agreement with the Company. Customers with a distributed generation system[65] of

---

[62] The generator forced outage rate (FOR) times standby contract demand should be factored into determining the cost the customer imposes on the system. Unlike full requirements loads, standby customers generally will not place as much of their total load on the system during peak periods. Daily as-used demand charges should be incorporated for backup power, and demand charges should also be recognized as on-peak versus off-peak.

[63] Delivery charges should reflect that customer generation will not all fail at the same time and shared transmission and distribution facilities are designed to meet demand by a pool of customers, not a single customer's need.

[64] For example, if the customer is able to reduce load when its generator is not available, the customer can avoid standby charges. Another option to avoid charges is for the customer to provide the Company with a load reduction plan that demonstrates its ability to reduce a specified amount of demand usage within a required timeframe in order to mitigate all or a portion of demand charges.

[65] Minn. Stat. 216B.164, subd. 2a defines "distributed generation" as a facility that: (1) has a capacity of ten megawatts or less, (2) is interconnected with a utility's distribution system, over which the commission has jurisdiction, and (3) generates electricity from natural gas, renewable fuel, or a similarly clean fuel, and may include waste heat, cogeneration, or fuel cell technology.

100 kW or less and customers who choose to provide physical assurance that they will not take standby service will not be required to take service under the Standby Rider.

MP also explained that the Rider differentiates between scheduled and unscheduled outage periods.[66] Customers are required to execute a Standby Service Agreement with the Company that includes Nominated Standard Service and Reserved Standby Service. Nominated Standard Service is billed according to the customer's standard service schedule. Reserved Standby Service is the amount the customer selects to have backed up by the utility. In months when the customer's generator does not experience an outage, the customer will be charged the Reservation Fee. The Reservation Fee is calculated based on the contracted standby MW amount, adjusted for customer's generator availability or how often the generator typically uses the Company's system assets. When the customer utilizes standby service during a Scheduled Outage, both the demand and energy are billed based on the customer's standard service schedule. Unscheduled standby service is available any time Scheduled standby service is not available.[67]

MP explained that the Standby Service Rider charges apply in addition to all charges for service taken under the customer's standard rate schedule. The three rate components for the Standby Service Rider are the Standby Reservation Fee, the Standby Demand Charge,[68] and the Energy Charge.[69]

To implement the terms of the Standby Service Rider, the Company needed to make revisions to its existing Electric Service Agreement for Distributed Generation Service. These include a reference to MP's Standby Service Agreement, removal of customer nameplate capacity rating, customer elections of firm and non-firm standby service, and a change in customer exemptions to systems rated at 100 kW or less.

MP proposed that the effective date for the updated Standby Service Rider be the first day of the month following the issuance of the Commission's order approving the new tariff.

DOC's comments on MP's revised Standby Service Rider

The DOC recommended that the Commission approve MP's revised Standby Service Rider as proposed, with no further revisions.[70] It concluded that MP's proposed Rider is reasonable and generally conforms to the rate design goals proposed by the DOC.

MCA/FE's comments on MP's revised Standby Service Rider

---

[66] MP included Standby service billing examples for a hypothetical Large Light and Power customer in its May 19, 2016 filing, Appendix 1.

[67] Demand charges during Unscheduled Outages will be determined based on the customer's 15-minute peaks in the on- and off-peak hours. For all kW of the customer's off-peak 15-minute peak in excess of the customer's on-peak 15-minute peak, the customer shall pay a lower demand charge, incentivizing the customer to shift Standby service during Unscheduled Outages to off-peak hours when possible, thereby minimizing the costs incurred by the utility. Energy during Unscheduled Outages is billed based on the hourly incremental cost to the Company to serve Standby load plus an energy surcharge.

[68] This charge is applied during months in which scheduled or unscheduled outages occur, unless the Standby Reservation Fee is greater than the sum of Unscheduled and Scheduled Standby Demand Charges. There is both a Scheduled and Un-Scheduled Demand Charge.

[69] The customer pays for all energy usage during both Scheduled and Unscheduled Outages, but at different rates.

[70] DOC, April 21, 2017, p. 3.

On April 21, 2017 and May 15, 2017, MCA/FE filed updates to its prior comments. It acknowledged that MP had made improvements to its current Rider, including the inclusion of a customer's Forced Outage Rate (FOR) and the use of daily as-used[71] demand charges for scheduled outages to reflect best practices.[72] However, it remained concerned with three aspects of the proposed Rider: (1) the monthly demand charge ratchet for unscheduled outages, (2) the limitation of scheduled outages to shoulder months, and (3) the lack of differentiated peak and off-peak demand and energy charges for unscheduled outages.

According to MCA/FE, MP applies a monthly demand charge to assess unscheduled standby outage charges that result in a seven-fold difference in the charge for unscheduled versus scheduled outages. It noted that although forced outage rates for on-site customer generation systems are often low, some level of forced outage is inevitable. MCA/FE argued that this type of structure, which MCA/FE refers to as a monthly ratchet of costs, creates a barrier to CHP deployment, does not fit best practices, and may not be cost justified.[73] Under MP's proposed Rider, any maintenance outage in a non-shoulder month is treated as an unscheduled outage and subject to the monthly ratchet. MCA/FE also recommended that scheduled outages not be limited to shoulder months.[74]

MCA/FE also argued that MP fails to differentiate peak and off-peak demand and energy charges for unscheduled outages. According to MCA/FE, standby services should be designed such that a cogeneration customer is encouraged to do small amounts of necessary maintenance during off-peak hours at night or on the weekend through charges that reflect the lower utility cost during these non-peak hours.[75]

MP's reply to concerns raised by MCA/FE

In response to MCA/FE's claim that MP failed to differentiate on and off-peak demand and energy charges, MP stated that it does use on-peak and off-peak charges during unscheduled outage periods.[76] A customer will be billed for only the Unscheduled Off-Peak Standby Service Demand that is in excess of its Unscheduled On-Peak Standby Service Demand.[77]

In response to MCA/FE's other concerns, MP explained that the Company has a unique customer mix with a handful of large customers that account for a significant portion of the Company's total system load. Under a daily as-used[78] demand pricing structure, as proposed by MCA/FE, the standby customer would contribute towards system peak, resulting in higher costs.[79] These costs would not be recovered through the daily charge proposed by MCA/FE.

---

[71] The "daily as-used" calculation means the scheduled standby rate is pro-rated by the number of days in the month that scheduled standby is used.
[72] ERC also filed comments supporting MP's revised reservation charge based on a monthly FOR and the Company's use of a daily, pro-rated calculation methodology for the scheduled standby service demand.
[73] MCA/FE, May 15, 2017, p. 8.
[74] MCA/FE, May 15, 2017, p. 8.
[75] MCA/FE, May 15, 2017, p. 8-9. MCA/FE cited OTP's tariff as an example of best practices. It suggested that MP incorporate the daily as-used demand pricing structure to recover costs associated with unscheduled outages.
[76] MP, November 9, 2016, p. 3.
[77] MP, November 9, 2017, p. 3. ERC raised this issue in initial comments but following MP's explanation, did not pursue it.
[78] A "daily as-used" calculation means the scheduled standby rate is pro-rated by the number of days in the month that scheduled standby is utilized. During unscheduled outages, the demand charge is not prorated based on the number of days in the month. The demand charge prorate applies to scheduled outages.
[79] Higher costs result from additional capacity requirements, MISO charges etc.

MP explained that it intentionally structured the unscheduled outage portion of the standby rate so as not to incorporate the daily Unscheduled Outage charge. The proposed pricing structure (the use of a monthly demand charge to assess unscheduled standby outage charges) is needed for the Unscheduled Outage charges. MP's rate structure reflects on- and off-peak pricing, along with the provision for Standby service during Scheduled Outages at lower rates. This provides a clear price signal to standby customers that encourages them to plan outages (or periods where the distributed generation system will not generate at historically normal levels) in non-peak months and avoid those outages (or periods) during higher-cost times.[80] MP also noted that billing scenarios provided by MCA/FE assumed no change in customer behavior during the unscheduled outage. However, MP's rider is structured to allow the customer to curtail load and reduce or avoid altogether the unscheduled demand charge.

In response to MCA/FE's requests for cost justification, MP responded that the Company's proposed Standby reservation and demand rates are based on revenue requirements[81] and billing units,[82] both of which were approved as part of the rate review in the 2009 rate case. MP plans to update the standby rates using the Commission-approved information at the end of its current 2016 rate case.[83] The updates will be submitted as a compliance filing in the standby docket, or submitted as part of the 2016 rate review compliance filing reflecting the Commission's final determination of that case. MP noted that this will ensure that the data used for the Company's rate calculations has been thoroughly reviewed and vetted by multiple stakeholders.[84]

Staff comment on MP's Standby Service Rider

Staff notes that the DOC recommended approving MP's proposed Standby Service Rider with no additional modifications or revisions. In response to concerns raised by MCA/FE, MP provided support for its pricing structure, specifically the unscheduled outage portion of the rate. It also explained the need to limit scheduled outages to shoulder months and indicated that cost justification for the level of the rates contained in the Rider will be reviewed in the context of the Company's ongoing rate case (Docket No. E-015/GR-16-664).

Large Power Intervenor (LPI) proposal to limit application of MP's Standby Service Rider to generation systems of 10 MW or less

On April 21, 2017, LPI filed updated comments.[85] It proposed that standby service for large customer-sited projects continue to be negotiated on a case-by-case basis and that MP make explicit that the application of its proposed Standby Service Rider is limited to distributed generation systems with a nameplate capacity of 10 MW or less.[86]

---

[80] MP, May 15, 2017, p. 2.
[81] Revenue Requirements are from the 2010 MP electric cost of service study, included in Company's 2009 retail rate case, Docket No. E-015/GR-09-1151, Compliance Filing, March 8, 2011, Section IX, page 19 of 34.
[82] Load Research Data and Estimated Class Demands Split by Voltage Level figures are included in Company's 2009 retail rate case, Docket No. E015/GR-09-1151, Rebuttal Testimony of Stewart J. Shimmin, Schedule 3, page 12 of 15 (April 29, 2010).
[83] Docket No. E-015/GR-16-664.
[84] MP, May 15, 2017, p. 1.
[85] LPI filed comments on November 9, 2016. However, staff assumes given the Commission's notice asking parties to update and file final comments that LPI's April 21, 2017 comments replace the earlier ones.
[86] LPI, April 21, 2017, p. 3.

LPI acknowledged that as currently proposed MP's Rider applies to customers who take service on a list of standard rate schedules,[87] have a distributed generation system capable of generation on a continuous basis, and who enter into an Interconnection Agreement. The proposed Rider does not state that it only applies to distributed generation with a nameplate capacity of 10 MW or less, which would be consistent with the State of Minnesota Interconnection Agreement. According to LPI, if a distributed generation system must have a nameplate capacity of 10 MW or less to sign the Minnesota Distributed Generation Interconnection Agreement, and a potential standby customer must sign that Agreement in order to take service under the Rider, then the size limitation in the Agreement must also apply to the Standby Service Rider. Following this logic, LPI recommended that language to this effect be added to MP's revised Standby Service Rider.[88]

LPI explained that each of its members has unique service needs requiring individual Electric Service Agreements (ESAs). From a strict load profile perspective, LPI members may appear to have similar operating characteristics but variations within LPI member industries exist that need to be reflected in customer-specific ESAs. For this reason, LPI recommended that the terms of standby service for distributed generation systems greater than 10 MW continue to be individually negotiated on a case-by-case basis, either as a separate contract or through an Electric Service Agreement and that MP make clear that the Rider is limited to distributed generation systems with nameplate capacity of 10 MW or less.[89]

DOC response to LPI's proposal to limit application of the standby tariff to generation systems 10 MW or less

In response to LPI, the DOC indicated that the scope of the current proceeding is to focus on distributed generation. It referred to the Commission's November 19, 2016 Order, which states:

> Utilities charge "standby" rates to certain distributed generation facilities to recover costs incurred to make electricity service available to those facilities. Standby service makes electricity available to generating facilities during planned and unplanned outages, among other needs.[90]

The DOC also noted that Minn. Stat. § 216B.164, subd. 2a(h) defines distributed generation as a facility with a capacity of 10 MW or less. Thus, the DOC concluded that consideration of standby service to facilities greater than 10 MW would need to be undertaken separately, in another docket, to reflect the requirements for such facilities, the effects on the utility's system, and the costs involved.

MP response to LPI's proposal to limit application of the proposed standby tariff to generation systems 10 MW or less

MP believes that the additional language as proposed by LPI is unnecessary because customers with on-site generation with a nameplate capacity of greater than 10 MW will have individual Electric Service Agreements (ESA's) negotiated with the Company. These individually-negotiated

[87] General Service, Large Light and Power Service, Municipal Pumping Service, and Large Power Service.
[88] LPI, April 21, 2017, pp. 2-3.
[89] LPI, April 21, 2017, pp. 2-4.
[90] *Order Requiring Tariff Filings*, in Docket No. E-999/CI-15-115, issued November 19, 2016, p. 2.

agreements will include specific terms on back-up generation, making the additional language unnecessary.[91]

Staff comment on LPI's proposal to limit application of MP's standby tariff to generation systems 10 MW or less

LPI seeks clarification of the size limit for the applicability of MP's Standby Service Rider. The parties appear to agree that the Rider will apply only to distributed generation systems with a nameplate capacity of 10 MW or less. A simple solution may be to clarify the tariff to reflect this agreement. MP has indicated a willingness to do so. Therefore, staff suggests the Commission accept MP's proposal and permit the Company to file revised tariff language clarifying the size limit for the application of the Rider as part of a compliance filing for DOC review.

[91] MP, May 15, 2017, p. 3.

Otter Tail Power's (OTP's) revised Standby Service Tariff

On May 18, 2016, OTP filed its updated Standby Service Tariff (Rate Schedule Section 11.01).[92] The tariff is applied as a stand-alone rate schedule, rather than a rider that applies to a customer's standard service. At the time the Company filed the updated tariff, it had no Minnesota customers taking service under the existing standby service rate schedule.

OTP explained that the revisions and updates to its standby tariff were based on a study prepared by ERC for the DOC,[93] as well as on the discussions at CHP stakeholder engagement meetings (held from September 2014 to December 2015). The ERC study provided a positive assessment of OTP's existing standby tariff, with three potential recommendations. OTP addressed the three recommendations as explained below.

The reservation charges should be unbundled into generation, distribution and transmission cost components. OTP simplified the unbundling information in its tariff by providing a percentage breakdown of the cost components instead of producing unbundled rates.

Clearly state whether non-firm standby customers may take scheduled maintenance service. In response, OTP added a statement in its tariff making clear that Scheduled Maintenance Service is applicable to both Firm Standby and Non-Firm Standby services.

The Forced Outage Rate (FOR) should be used in the calculation of a customer's reservation charge to incentivize the customers to limit their use of backup service.[94] OTP understands this recommendation from a theoretical basis, but not from a practical one. Therefore, this change was not made. OTP explained that customers with on-site generation do not collect, maintain and verify Forced Outage Rates (FORs) for these generators. Instead, MISO typically performs this function for utilities. OTP also questioned whether the administrative costs to obtain individual customer FOR calculations are worth the effort. Finally, OTP argued that for a customer FOR to be meaningful, it must be greater than the utility FOR.[95]

DOC comments on OTP's updated Standby Service Tariff

The DOC commented that providing rate transparency by unbundling generation, transmission and distribution charges is an important rate design goal for standby rates and that OTP addressed this recommendation by including a table in its proposed tariff defining the percentage of each rate component that represents transmission or distribution service. However, the DOC suggested that instead of a table with percentages, the Commission require OTP to file the rates associated with each category.[96]

---

[92] OTP's May 18, 2016 filing was a petition requesting approval to update its Standby Service Tariff. On May 12, 2017, the Company filed an addendum to its initial filing that contained the revised/updated Standby Service rate schedule.
[93] The ERC study was filed prior to the Commission's November 19, 2015 Order, and was part of the record leading up to that Order and the Commission's decision to ask utilities to file individual standby tariffs.
[94] Forced Outage Rate (FOR) of a generating unit for a given time span is defined as the number of hours the unit is forced out of service for emergency reasons divided by the number of total hours that the unit is available for service during that time interval plus the number of hours during a forced outage. The FOR measures the probability that the unit will not be available for service when required. (RAP, *Standby Rates for Combined Heat and Power*, February 2014)
[95] OTP, May 18, 2016, pp. 4-5.
[96] DOC, April 21, 2017, p. 4.

Regarding the use of customer Forced Outage Rates (FORs), the DOC suggested using the Company's average fleet FOR. According to the DOC, this would address OTP's concern about the administrative burden of determining the FOR of a distributed generator. The DOC noted that all generators have some level of forced outage rate but when the customer FOR is unknown due to a lack of operating experience, using the utility's average FOR may be a reasonable alternative. The DOC recommended that the Commission require OTP to incorporate the average FOR of its generation fleet in the determination of a reservation charge.[97]

The DOC noted that of the three utilities with a customer charge, OTP's monthly customer charge, as well as its Standby Local Distribution Facilities Charge, are significantly higher. It noted that the Standby Service customer charge should reflect only the incremental cost of providing standby service to the customer. The DOC assumed that most standby customers will also be taking service from the utility under one of its standard tariffs and paying a monthly customer charge. However, the DOC understands that OTP currently has no Standby Service customers. Thus, it is not known whether or not customers seeking Standby Service would take any other service from the Company. Nevertheless, the DOC requested that OTP explain how it will apply its tariff to a customer with a portion of its load served by OTP and the remainder served by a distributed generation system.[98]

MCA/FE comments on OTP's updated standby service tariff

MCA/FE commented that OTP's proposed standby tariff reflects many "best practice elements." Unlike the other three utilities, OTP adopted a separate standby tariff rather than a standby rider. The tariff includes a 2-page table clearly summarizing the tariff charges (see discussion below on OTP Summary of Charges Table). MCA/FE believes OTP's summary of charges table is a good model for the Commission to adopt for use with other utility standby tariffs. MCA/FE argued that the stand-alone nature of the tariff and summary table make OTP's standby tariff the most transparent and readily understandable to cogeneration customers, the Commission, and the public of all four of the Minnesota rate-regulated utility tariffs.[99]

MCA/FE also pointed out that OTP's standby tariff addresses the unique "partial use" nature of non-intermittent cogeneration customers with proportional and "time of use" charges. It differentiates peak/off-peak "time of use" and scheduled/unscheduled use in its pricing. It also provides a seasonal use price differential. It applies no demand charges for scheduled outages, recognizing that scheduled outages do not impose infrastructure or capacity costs on the utility. MCA/FE also indicated that OTP's demand charges for unscheduled standby service are reasonable.

MCA/FE noted that OTP applies a flat fixed reservation fee, but the fee is quite low compared to other utility reservation fees. MCA/FE found OTP's customer charge to be reasonable. However, it noted that OTP also applies a "standby facility charge," which may be appropriate, but should be cost justified.[100]

In sum, MCA/FE applauded the fact that OTP had designed its standby service tariff in a manner that is proportional and encourages efficiency with clear price signals to its self-generation customers. In

[97] DOC, April 21, 2017, p. 4.
[98] DOC, April 21, 2017, p. 5.
[99] MCA/FE, April 21, 2016, p. 13.
[100] MCA/FE, April 21, 2017, p. 13. MCA/FE recommended a second round of revisions to all the tariffs to review their cost justification.

response to DOC comments, MCA/FE provided further comments. The DOC comments highlighted several issues, including the need to unbundle the transmission and distribution reservation fees, the possibility of using the forced outage rate (FOR) of the utility's generation fleet as a proxy for a customer's FOR, and uncertainty around how the standby tariffs would apply to standby customers with a portion of their load served by OTP. MCA/FE agreed that unbundling charges within specific fees can create greater transparency in standby tariffs. However, it believes that if this is required of OTP it should be applied to the other utility tariffs to create the same transparency benefits.[101]

MCA/FE did not agree with the DOC recommendation that OTP should use the fleet Forced Outage Rate (FOR) as a proxy for the FOR of on-site non-intermittent generation projects because the record in this docket does not include the average FOR of OTP's generation fleet. Therefore, parties do not have a fair assessment of how this rate compares with on-site CHP projects.[102]

OTP reply comments

On June 9, 2017, OTP filed additional comments in order to clarify the three issues raised by the DOC (which the Company believes have already been addressed). First, the DOC requested that OTP include the rate components for transmission and distribution reservations fees in its tariff. However, in its initial petition filed May 18, 2016, the Company explained that it planned to unbundle these costs and to provide them in a filing at the close of its rate case. As indicated, the Company unbundled the reservation charges into generation distribution and transmission cost components and included them in its proposed standby service tariff filed on May 12, 2017.

Second, in response to the DOC request that OTP calculate its rates assuming the forced outage rate of its own generation fleet, the Company noted that this issue was addressed in its May 18, 2016 petition. In that filing, OTP proposed to use the forced outage rate for its own generation fleet in lieu of individual customer FOR information. OTP believes the Company's generation fleet forced outage rate is not unreasonable as argued by MCA/FE. The Company agreed with the DOC and accepted its recommendation to continue the practice of using its own generation fleet outage rate.[103]

Lastly, the DOC asked for an explanation of how standby service rates would apply to a standby service customer with a portion of its load served by OTP. The Company responded that it had provided this information in an IR response to Fresh Energy[104] and it asked the DOC to review that response. OTP explained that the IR response indicates that OTP will supply the services the customer needs based on the operation status of the generator. If the generator has a forced outage, OTP will provide back up. If the customer's load exceeds the generation output, OTP will provide supplemental power. If the customer is down due to scheduled maintenance, OTP will supply the customer's needs. Regardless, under each of these scenarios, the customer will incur only one customer charge for the metering related to standby service.[105]

Staff comment on OTP's standby service tariff

---

[101] MCA/FE, May 15, 2017, p. 6.
[102] MCA/FE, May 15, 2017, p. 6.
[103] OTP included the derivation of the fleet FOR calculation in its June 9, 2017 filing (Attachments 1 and 2), and proposed to update the proposed standby tariff if the Commission adopts this proposal by OTP and DOC.
[104] OTP, June 9, 2017, Attachment 3.
[105] If a standby service customer takes supplemental service, and a separate meter is required to measure this service (i.e. one meter cannot measure both rates), then the meter charges from the supplemental service will also apply to the bill.

As noted above, on June 9, 2017, in an attempt to narrow the issues and address each of the DOC's concerns, OTP submitted an additional filing. Staff believes that with the information in this additional filing, OTP has addressed the DOC's concerns, although the DOC will need to affirm this at the meeting.[106] Moreover, staff notes MCA/FE appears to support approval of OTP's Standby Service Tariff, although it seeks further cost justification of OTP's standby facilities charge.

Dakota Electric Association's (DEA's) revised Standby Service Rider

On May 19, 2016, Dakota Electric Cooperative (DEA) filed its updated Standby Service Rider.[107] It explained that the proposed changes are meant to streamline and simplify the current rider. Currently, only two customers take service under the rider and DEA is not aware of any other customers wishing to take service under it.[108]

As described by DEA, the purpose of its standby service is to provide utility service to members when their on-site generation is not available to meet all or a portion of their load. The proposed Standby Service Rider is applied to consumers that are receiving electric service under one of DEA's firm retail electric rate schedules[109] and are operating an on-site distributed generation system to meet some or all of their electrical requirements.[110] The proposed Standby Service Rider is applicable to both intermittent and non-intermittent facilities.

Under the proposed Rider, DEA would apply two types of reservation fees: (1) a wholesale power supply reservation fee, which is basically a "pass-though" rate and is billed under the rates, terms and conditions of DEA's wholesale supplier (GRE), and (2) a distribution service reservation fee. Both reservation fees are charged based on the amount of load served by the on-site generation facility (billed on a per kW basis).[111]

For wholesale power, the proposed tariff would bill a customer for the same wholesale power charges that GRE would bill DEA for the identified standby consumer. DEA's Standby Reservation Fee recovers the costs of owning, operating, and maintaining distribution facilities so they are available when firm and standby consumers need electricity from the utility. If DEA does not plan to serve standby consumers, then the capacity to provide service may not be there or it could limit the Cooperative's ability to reconfigure the system during outages or contingency situations when standby consumers have electric consumption. Such circumstances could lead to deterioration in reliability for DEA's firm service consumers.

In response to certain stakeholder comments on the proposed Rider, DEA offered to develop and file a new rate schedule for standby service customers with on-site generation that runs most of the time,

---

[106] Staff has contacted the DOC but has not been able to clarify the issue.

[107] See Schedule 60, attached to DEA's petition. Also included in the May 19, 2016 filing were DEA's proposed updates to the Commission's distributed interconnection standards and process. These were moved into the Commission's generic docket updating the State interconnection standards (see Order, in Docket No. 16-521, issued January 24, 2017).

[108] DEA has two customers taking service under its current standby rider—a 133 kW solar installation and a larger natural gas wholesale generator. DEA has no CHP facilities on its system and is not aware of any being planned at this time.

[109] When a customer-member uses utility service under the Rider, the consumption (demand and energy) is billed under the applicable retail rate schedule.

[110] DEA explained that presently firm electric service is likely to be obtained through the General Service rate (Schedule 46). So typically an existing customer (Schedule 46) decides to install a distributed generation system that is larger than 40/60 kW and that would implement the Standby Service Rider.

[111] DEA, May 19, 2016, p. 6.

such as CHP facilities. The new rate schedule would be designed to provide all of a customer's electrical requirements. Customers taking service under the new schedule would also have the option of taking service under the proposed Standby Service Rider in combination with the new rate schedule, or under the General Service Rate (46) in combination with the proposed Rider.

DOC comments on DEA's revised Standby Service Rider and proposal to file a CHP-specific rate schedule

The DOC acknowledged that as a distribution cooperative, DEA's reservation fees for generation and transmission are billed under a tariff provided by GRE. It also acknowledged that DEA revised its current standby rider by adding a reservation fee for distribution substation service, a monthly communication fee to cover the cost of transmitting meter data, and a wheeling fee. The DOC noted that, with some exceptions, the revised Rider applies to any member with distributed generation facilities.[112] However, it noted two concerns with the Rider: (1) it does not distinguish between use of standby service during scheduled and unscheduled outages in its application of rates for standby service, and (2) it applies to intermittent resources such as solar generation.[113]

The DOC noted that DEA had agreed to develop and file a separate rate schedule for CHP-type facilities. The new rate schedule will include a monthly non-coincidental demand charge in lieu of the Standby Reservation Fee and a coincidental demand charge that will apply if usage occurred during the monthly peak billing period of its wholesale provider. The DOC noted that in the event usage occurs during coincident peak periods, monthly charges under the new schedule could result in substantially higher charges than under the proposed Standby Service Rider.[114]

In its final set of comments,[115] the DOC recommended that the Commission require DEA to file the proposed rate schedule, along with cost support. The DOC also recommended that DEA file an explanation of how forced outage rates for customer-sited generators will be incorporated into the new rate schedule. The DOC does not believe the Commission should approve DEA's proposed Standby Service Rider until the CHP-specific rate schedule is filed.

MCA/FE comments on DEA's Standby Service Tariff

In comments filed April 21, 2017, MCA/FE argued that DEA's proposed Standby Service Rider as proposed does not meet best practices for standby service. It argued that the Rider: (1) applies a high flat fixed fee for standby usage, and (2) fails to differentiate pricing for peak and off-peak usage or scheduled and unscheduled usage. MCA/FE claimed that under this structure the tariff will over-recover costs, not reflect the duration of standby service usage, and discourage energy efficient cogeneration projects in the DEA territory.[116] However, after discussions with DEA, MCA/FE agreed to the filing of a specific tariff incorporating principles and revisions suggested by MCA/FE, including:

[112] Exceptions include members taking service under the Rider for Parallel Generation with generation systems under 40 kW, or members taking service under the Rider for Distributed Generation Service, with generating systems under 60 kW or less.
[113] DOC, April 21, 2017, p, 3.
[114] DOC, April 21, 2017, p. 3.
[115] DOC, May 15, 2017.
[116] MCA/FE, April 21, 2017, p. 13.

- the application of variable demand charges that reflect system peaks in order to reward customers who optimize their CHP systems to use grid backup service as little as possible

- providing lower reservation/demand charges for pre-planned maintenance that can be scheduled for off-peak hours and/or during low demand seasons in order to encourage customers to adequately maintain CHP systems and minimize unplanned "forced outages"

- providing rates that differentiate between peak and non-peak time of use in order to reward customers who can shift load to minimize use of back-up service during peak hours

MCA/FE concluded that the new CHP tariff design as proposed by DEA appears to result in reduced standby charges overall. However, it believes even under the new structure, DEA's charges may remain higher than those of other Minnesota rate-regulated utilities. For this reason, MCA/FE recommended that DEA include cost justification information with its new CHP tariff filing, as well as 8,760 hour demand data.[117]

MCA/FE understands that DEA is in discussions with GRE on wholesale energy charges and coincident system peaks and that these discussions involve other GRE member distribution cooperatives. Yet, MCA/FE argued DEA's provision of the cost justification and the 8,760 hour data suggested above should not be delayed since it is necessary to understand the rationale for DEA's high fixed charges. MCA/FE also supported the DOC recommendation that DEA include cost support for the proposed CHP rate schedule, as well as an explanation of how DEA incorporates forced outage rates into its new rate schedule. MCA/FE did not support DEA's proposal to approve the Standby Service Rider (filed May 19, 2016) in the interim prior to the approval of a CHP-specific tariff.[118]

DEA's response to the DOC and MCA/FE

In response to requests for additional explanation of how standby service would apply to solar distributed generation facilities, DEA explained that if intermittent resources did not take service under the proposed Rider, then standby service for these customers would be provided at no charge. DEA bills for the costs of distribution service and wholesale power under various retail rate schedules. However, when intermittent generation is installed, DEA needs to have distribution facilities in place to provide service for these on-site generators. If intermittent distributed generation reduces the consumer's highest demand during a billing month, then the charges under the retail rate schedule will be lower. If the intermittent distributed generation is not operating during the consumer's highest demand during a billing month, then the charges under the retail schedule will be the same. In short, even under standby service, these customers will not pay more than what they would pay under their retail rate schedule for the standby service provided, and therefore, they are not being penalized for the standby service.

In addition, DEA provided examples showing how solar distributed generation facilities will be billed under the proposed Rider, citing different standby service scenarios and billing examples in Exhibit B of its initial May 19, 2016 filing. In sum, DEA believes that the proposed modifications and revisions to its existing Standby Service Rider appropriately cover provisions for both intermittent and non-intermittent standby service.[119]

[117] MCA/FE, April 21, 2017, p. 14.
[118] MCA/FE, April 21, 2017, p. 13-14.
[119] DEA, May 19, 2016, Exhibit B.

Also, as noted above, in order to address parties' concerns regarding the application of the proposed Rider to CHP facilities, DEA offered to develop a new rate schedule for customers with on-site generation designed to meet the customer's electrical requirements most of the time (e.g. CHP facilities). The new schedule will be the firm service schedule to which the proposed Standby Service Rider would apply, and the vast majority of rate components will be a pass-through of wholesale power costs from GRE. However, there will also be recovery of DEA's distribution system costs, similar to its present retail rates.[120] The new rate schedule will incorporate an unbundled rate design suitable for the operating conditions of a CHP-type facility. DEA believes that the new rate schedule will result in charges comparable to the other regulated electric utilities, while allowing DEA to recover both distribution and wholesale power costs of providing service.[121]

In response to the DOC's request that DEA further explain how it accounts for a generator's forced outage rate in the development of rates, DEA explained that it is important to separate the distribution service provided by DEA from the wholesale power purchased from GRE. DEA does not determine the design of the generation and transmission rates, nor the use of forced outage rates in the design of the G&T rates, which are pass-through rates from GRE.[122] However, DEA designs and builds its distribution system to meet the local/on-site load requirements of individual consumers (e.g. transformers) and the diversified load requirements of consumers in specified areas (e.g. feeders consisting of poles, wires, underground cable and substations). DEA does not have forced outage rates for member-owned generation equipment. The distribution system is designed, built and maintained to handle the entire member load without consideration of the generation availability. The distribution standby charge is intended to collect revenue to pay for the cost of these facilities.

In response to MCA/FE's claim that DEA's proposed Rider contains high flat fees that discourage energy efficient cogeneration projects, DEA reiterated that its distribution Standby Reservation Fees are based on the cost of owning, operating, and maintaining distribution facilities that are required to provide electric service to standby consumers when on-site generation sources are not available to meet the consumer's electrical requirements. The costs for these facilities are on-going and appropriately recovered through existing standby demand charges. Intermittent use of required distribution facilities does not mean the cost to the utility of providing this service is intermittent. The cost analysis and support for the Standby Reservation Fees have been reviewed and approved in each of the past several DEA general rate cases, and charges for consumption by standby consumers are presently authorized by existing rate schedules. DEA has acknowledged a need for, and proposed to develop, a new rate schedule for standby consumers with non-intermittent resources. This will align

[120] On May 15, 2017, DEA filed comments clarifying some of the confusion surrounding its proposal for the yet-to-be-filed rate schedule. To address DOC confusion, DEA clarified the relationship of the Standby Reservation Fee and the Non-coincidental Demand Charge. It explained that the applicable Standby Reservation Fee would be applied in all months when there is no electrical consumption by the standby service customer. Only in months when there is electric consumption would the proposed monthly Non-coincidental Demand Charge be applied in lieu of the applicable Standby Reservation Fee that recovers distribution system cost.

[121] DEA described in detail what the new rate structure would look like in comments filed on April 21, 2017.

[122] DEA's wholesale power charges for consumption from GRE have nothing to do with forced outage rates of intermittent generation. If the consumer uses energy during a defined on-peak period, then DEA would bill the consumer for the on-peak energy it purchases from GRE. If the consumer uses energy during a defined off-peak period, then DEA would bill the consumer for the off-peak energy DEA purchased from GRE. If the consumer has demand during the monthly wholesale coincident peak period, then DEA would bill the consumer for the generation capacity purchased from GRE. If the consumer has demand during the monthly wholesale transmission billing period, then DEA would bill the consumer for the transmission service DEA purchased from GRE. These charges are all established contractually. (DEA, May 15, 2017, pp. 3-4.)

the wholesale power cost of providing service, within the confines of DEA's existing all-requirements wholesale power contract with GRE. Given this, DEA believes MCA/FE's statement that "DEA is over-recovering its costs" is baseless.[123]

In response to MCA/FE's request that DEA provide cost justification for the new CHP rate schedule and 8,760 hour demand data, DEA explained that its distribution Standby Reservation Fees are based on the cost of owning, operating, and maintaining distribution facilities that are required to provide electric service to standby consumers when on-site generation sources are not available to meet the consumer's electrical requirements. The costs for these facilities are on-going and are appropriately recovered through existing standby demand charges. To provide further perspective, DEA explained that a hypothetical 2-3 MW load would represent a significant portion of the usable capacity on many of DEA's feeders. The utility must have the ability to charge standby consumers for the costs of having these facilities in place just in case they are needed. The consumption charges in the proposed new tariff would be a direct pass-through of wholesale power costs from GRE, plus recovery of DEA's distribution costs (in combination with standby charges).

Also, DEA indicated that it does not serve any CHP facilities and is therefore unable to provide 8,760 hour demand data for each customer with a CHP generation system over the most recent 12 months as requested by MCA/FE in April 21, 2017 comments.[124]

Staff comments on DEA's proposal for a Standby Service Rider and proposal for a new Rate Schedule for CHP customers

Staff notes that DEA offered to file a new rate schedule for customers with on-site CHP-type generation facilities. Therefore, staff suggests that the Commission accept DEA's offer and require that the new rate schedule be filed within 60-90 days.[125] DEA has indicated to staff that it may file the new rate schedule prior to the Commission meeting on August 24, 2017.

Parties appear to support DEA's proposal to file the new rate schedule but also argue that the Commission should delay approval of DEA's proposed Standby Service Rider (filed on May 19, 2016) until the new rate schedule can be evaluated. Both MCA/FE and DOC have indicated that they would like to review the new rate schedule before DEA's proposed Standby Service Rider is approved in order to evaluate the interaction of the two. The Commission will need to consider whether delaying approval of DEA's proposed Standby Service Rider until parties are able to evaluate and comment on the new rate schedule is appropriate. The Commission may wish to hear from parties on this issue at the meeting.

MCA/FE standardized approach (Model Standby Service Template)

MCA/FE proposal

In November of 2016, MCA/FE offered a Model Standby Service Tariff Template, summarized in Table 10 below. It stated that the goal of their approach was "transparent, cost-driven standby charges which promote energy and efficiency."[126] Although initially calling for this template to apply

[123] DEA, May 15, 2017, pp. 4-5.
[124] DEA, May 15, 2017, p. 6.
[125] The Commission could consider assigning the filing a new docket number specific to Dakota Electric Association.
[126] MCA/FE, November 9, 2016, p. 13.

uniformly to all four rate-regulated utilities as a basis for a standby service tariff, MCA/FE subsequently made clear that they are not recommending complete standardization of utility standby tariffs, and acknowledged that "different utility service territories present unique costs and system characteristics, and that a one-size-fits-all standby tariff may not neatly apply across the regulated utilities in this docket."[127]

	Table 10. MCA/FE Model Standby Service Tariff Template
Customer Charge	Consistent with, but do not duplicate, full-time user tariff charge AND Charge or credit to reflect greater or lesser administrative costs associated with partial use customer.
Reservation Fee	Zero and recover in the demand charge OR Fixed fee to recover utility's embedded costs for capacity, transmission, and distribution based on the forced outage rate of last 12-month usage period or, in the first year of operation, best performing systems in the technology.
Demand Charge	**Scheduled Outage** Zero OR Variable demand charge proportionate to hours of planned usage and reflecting utility's cost differential due to planning at times that impose zero or low cost to utility. AND Variable demand charge for off-peak usage to reflect utility's cost differential during off-peak hours. **Unscheduled Outage** If no Reservation Fee, variable demand charge designed to recover proportion of utility's embedded costs for capacity, transmission, and distribution based on partial-use customer's hours of unscheduled use. OR If a fixed Reservation Fee is also charged, variable demand charge designed to recover utility's embedded costs for capacity, transmission, and distribution based on partial use customer's proportionate use above Forced Outage Rate assumed in Reservation Fee. AND Variable demand charge for off-peak usage to reflect utility's cost differential during off-peak hours.
Energy Charge	If no Reservation Fee and/or Demand Charge, recover proportion of utility's embedded costs for capacity, transmission, and distribution in energy charges based on partial-use customer's hours of use. Pricing should reflect utility's cost differential for scheduled usage and off-peak usage. OR

[127] MCA/FE, April 21, 2017, pp. 14-15.

	If embedded capacity, transmission, and distribution costs are recovered in Reservation Fee and/or Demand Charge, pricing should reflect utility's energy cost only. AND Pricing should reflect peak and off-peak energy prices or real time energy prices.
Transparency	Standby tariffs should be simple and understandable, include all information necessary to calculate total standby charges and the components of standby tariffs imposed on a customer, and follow a uniform format established by the PUC to allow comparison across utility tariffs by all parties and stakeholders.

Source: MCA/FE, November 9, 2016, pp. 14-15.

Following the filing of individual utility tariffs, MCA/FE recommended that utilities be required to redesign their standby service tariffs to reflect as fully as possible the uniform standby tariff methodology in Table 10 or demonstrate an alternative design which incorporates the same best practices although, as noted, it acknowledged that complete uniformity was not feasible.

The more specific recommendations to the Commission made by MCA/FE in its May 15, 2017 reply comments include: (1) adopting Table 10 as a model framework for incorporating best practices, (2) establishing a schedule to implement these design elements, (3) adopting a two-page summary standby tariff table based on OTP's proposal, (4) establishing a schedule for the two page table adoption, and (5) establishing a schedule for utilities to submit and receive comments on cost justification for standby service charges based on the proportion of customer costs incurred and annual hourly demand data.[128]

The MCA/FE template was endorsed by the Alliance for Industrial Efficiency.[129] Innovative Power Systems also endorsed a standardized methodology for all rate-regulated utilities but acknowledged that it needed to be "flexible for individual utilities with differing load profiles."[130] ERC noted that a generic, universal standby rate under the guidance of the Commission would be a simple approach to addressing all of its comments.[131]

Utility response to MCA/FE's proposal to adopt and apply a more standardized approach

The utilities emphasized their individual differences as a reason to maintain less than a fully uniform or standardized approach to standby service tariffs. For example, Xcel's response to the standardized MCA/FE template was that the model template does not provide a complete framework, lacks coordination with existing tariffs in terms of service and is insufficiently flexible for design innovations.[132] Xcel's view was also reflected in its comments filed November 9, 2016, citing the need for utility-specific approaches to standby service, noting that "utilities have a spectrum of unique operational, administrative, and jurisdictional attributes" that "do not necessarily lend themselves to uniform rate designs or administrative rules."[133]

In addition to Xcel, other utilities objected to further standardization proposed by the MCA/FE approach. Both MP and DEA cited "unique characteristics of load, rate design and power supply

[128] MCA/FE, May 15, 2017, p. 3.
[129] Alliance for Industrial Efficiency, April 21, 2017, p. 3.
[130] Innovative Power Systems, April 18, 2017, p. 1.
[131] ERC, August 19, 2016, p. 8.
[132] Xcel, April 21, 2017, p. 4.
[133] Xcel, November 9, 2016, p. 7.

agreements."[134] MP maintained that its "proposed tariff contains many of the elements included in the template."[135] OTP noted that its own standby proposal also "does not appear to differ materially to their template proposal."[136]

Despite its opposition to the MCA/FE template as proposed, Xcel emphasized that it has been highly responsive to the DOC's recommendations. Xcel provided a side-by-side comparison of the DOC's recommendations and how Xcel's proposal responds to them.[137]

Like Xcel, MP, OTP and DEA objected to the concept of a standardized template in part for reasons relating to their different circumstances noted above, but also because they felt that their proposals for standby service were already largely responsive to MCA/FE's concerns. MP, for example, noted that its large industrial customers bring larger costs and risks during peak periods, but that its proposed energy charge is consistent with MCA/FE's Table 10 template and that MP achieves transparency through direct communications with its customers. MP gave emphasis in its April 21, 2017 comments to its "unique customer mix". MP noted that industrial customers bring larger costs and risks to the utility, especially if standby is required during peak times. MP, commenting on the different characteristics of each utility, emphasized differences in time and frequency of standby service, differences in load profiles as well as customer size differences.[138]

As Xcel noted in its comments filed November 9, 2016 (p. 7):

> Utilities in this proceeding have raised important considerations about the need for utility-specific approaches to standby service. Similar to large customers and renewable energy developers, utilities have a spectrum of unique operational, administrative, and jurisdictional attributes. These differences are significant and do not necessarily lend themselves to uniform rate designs or administrative rules. As the Company has previously stated, this proceeding must take into account the need for compatibility with existing utility structures, including existing tariffs. We support utility-specific approaches to providing standby service and to serving customers with intermittent on-site generation.

Department response to MCA/FE's proposal for further standardization of utility proposals

The DOC did not indicate that further standardization, beyond its May 15, 2017 comments, was necessary. The DOC recommended approval of MP's proposed standby tariff at this time and proposed that OTP file additional information. The DOC also supported DEA's proposal to file a separate CHP standby service rate schedule.

Staff comment on standardization of standby tariffs

The Commission must weigh the benefits of a standardized or uniform approach to standby service tariffs against the differences in the four rate-regulated utilities' base customer services, including rate continuity, load profile and current rate designs. Although the DOC has called for common principles

[134] MP, April 21, 2017, p. 4. DEA, April 21, 2017, p. 12.
[135] MP, April 21, 2017, p. 5.
[136] OTP, April 21, 2017, p. 2.
[137] Xcel, April 21, 2017, p. 3.
[138] MP, April 21, 2017, pp. 4-8; MP, November 9, 2016, p. 2.

and best practices, neither it nor the Commission called for completely standardized tariffs. Although the standardized approach reflected in MCA/FE's Table 10 may, like the DOC principles, help to guide standby tariff design, greater consistency in standby tariffs across utilities can be achieved without making them uniform through adoption of the table.

In particular, the Commission may ask the utilities to explain further how their tariffs relate to the standardized approach and where the tariffs differ due to different utility characteristics and overall rate structures. However, staff believes the utilities may already have met this obligation. If the Commission finds that the utilities' approaches are somewhat different, but that sufficient reason has been given for these differences, it could approve the tariffs without formally adopting a further standardized approach, recognizing that further standardization will remain a goal over time.

OTP's Summary of Charges Table

Introduction

In its notice issued February 17, 2017, the Commission asked parties to comment on whether more standardization of standby service tariffs across the four rate-regulated utilities was reasonable, or even possible. One area of agreement appeared to be utility adoption of a "Summary of Charges Table," similar to the one proposed by OTP as part of its tariff.

Positions of the parties

MCA/FE proposal to adopt OTP's summary of charges table

In comments filed April 21, 2017, MCA/FE emphasized the importance of transparency in standby service tariff design. It argued that transparency is an important principle and objective of standby service tariffs design because it will provide customers with rates that are understandable, allowing for more customer choice. MCA/FE noted that this critical aspect of standby tariffs has been discussed in comments and stakeholder meetings throughout this docket. Standby tariff structure and language should concisely communicate the charges that the customer will incur under variable operating scenarios. To achieve this, MCA/FE recommended a minimum of cross-references to other tariffs, ambiguous language, and hidden surcharges.[139]

Given the complexity of standby tariffs due to unique elements of a utility's underlying tariffs, MCA/FE recommended that the Commission adopt a standard 1-2 page Summary of Charges Table that clearly identifies different fixed and variable customer charges, reservation fees, demand charges and energy charges under the tariff.[140]

As noted above, MCA/FE applauded OTP for providing a good example of such a summary table in its proposed standby tariff and suggested that the table could be replicated by the other rate-regulated utilities. It recommended that the Commission require the other three rate-regulated utilities to prepare a similar table.[141] MCA/FE noted that by unbundling transmission and distribution fees and using the

[139] MCA/FE, April 21, 2017, p. 11.
[140] MCA/FE, April 21, 2017, p. 11-12.
[141] OTP's summary cost table is included in MCA/FE's April 21, 2017 comments, Attachment B, and as part of OTP's May 12, 2017 filing of the proposed standby tariff.

utility FOR as a proxy for customers, the OTP summary cost table achieves greater transparency.[142] MCA/FE also noted that the DOC found it to be a useful tool for comparing standby services and that the Commission should require all utilities to provide such a table.[143]

MCA/FE recognized that incorporating this table into a formal tariff filing might inhibit flexibility in modifying or updating the table in a timely fashion. The same purpose could be achieved if the table was made available for stakeholder and public review in a readily accessible location on the utility's webpage.[144]

Minnesota Power's comments on OTP's cost sheet

MP stated that it does not favor "having a standard template for all utilities due to unique characteristics" of each utility. It also noted that its industrial customers "bring larger costs and risks to the utility," especially during peak times.[145] However, MP noted that it favored transparency which it hoped would result from its "key account management program," which communicates with customers regarding standby service. It made no specific reference to a summary of charges table,[146] but explained in detail how its standby service structure compares to the MCA/FE model standby service template.[147]

Dakota Electric's comments on OTP's cost sheet

DEA, as noted above, explicitly rejected the MCA/FE model standby service tariff described in Table 10 and therefore implicitly rejected the OTP Summary of Charges Table endorsed by MCA/FE. Instead, DEA offered "Billing Examples," including several examples of how its standby service charges would be billed monthly in Exhibit B of its May 19, 2016 filing.[148] Commenting on transparency issues generally, DEA volunteered to provide standby scenario examples on its website rather than as part of its formal tariff filing.[149] The examples provided in Exhibit B of its May 19, 2016 filing break out cases in which a customer's generation meets all, some, or none of its overall electric energy requirements.

In its April 21, 2017 comments, DEA repeated that it had no objection to providing examples of its standby rates, but instead of filing them as part of the tariff, it would provide them as updates on its website.[150]

Xcel's comments on OTP's cost sheet

While Xcel did not comment specifically on the OTP Summary of Charges Table, its general position concerning the MCA/FE template was negative. This does not necessarily signal opposition to a summary of charges table, but does suggest that each utility has a unique position so that uniformity in the categorization of charges is unlikely.

---

[142] MCA/FE, May 15, 2017, p. 6.
[143] MCA/FE, May 15, 2017, p. 3.
[144] MCA/FE, April 21, 2017, pp. 11-12.
[145] MP, April 21, 2017, p. 4.
[146] MP, April 21, 2017, p. 8.
[147] MP, April 21, 2017, pp. 5-8.
[148] DEA, May 19, 2016, Exhibit B.
[149] DEA, April 21, 2017, p. 14.
[150] DEA, April 21, 2017, p. 14.

DOC's comments on OTP's cost sheet

The DOC agreed that a summary table could reduce confusion and provide customers with a useful tool for comparing standby services. Therefore, it recommended that the Commission require utilities to provide a one page summary table for distribution to standby service customers.[151]

In its earlier comments, although it did not focus specifically on OTP's summary table, the DOC highlighted several areas of OTP's proposed standby tariff, including the need to unbundle the transmission and distribution reservation fees. The DOC agreed that unbundling charges within specific fees can create greater transparency in standby tariffs, and noted that MCA/FE suggested that if this is required of OTP it should be applied to the other utility tariffs to the extent that it is not already to create the same transparency benefits.

Staff comment on MCA/FE proposal that Xcel, MP and DEA submit a cost sheet similar to OTP's Summary of Charges Table

Staff notes that the Commission may find reasonable MCA/FE's proposal to require all four rate-regulated utilities to provide a summary of charges table for standby service customers. Staff agrees that the OTP table clearly describes the structure of OTP's standby tariff and should serve as a model for the other three utilities and their customers, but acknowledges that the OTP table is only a prototype that may require adjustments if replicated by the other three utilities. Therefore, the Commission may wish to consider requiring that each utility prepare such a summary table and submit it as part of a compliance filing for DOC review.

Staff also agrees with MCA/FE that requiring the utilities to incorporate a summary table in their tariff filing may inhibit flexibility in modifying or updating the table in a timely fashion, and that the same purpose might be achieved if the table is not incorporated into the tariff itself. The summary table could instead be made available in a readily accessible location on the utility's webpage. Insofar as possible, each utility should strive to use similar cost categories.

Staff also suggests that the Commission consider whether the summary of charges table compliance filings made by utilities will be similar enough to a customer notice that they could be treated as such. If so, the Commission would need to delegate review authority to the Executive Secretary to approve the content. Under the Commission's current notice review process, the summary cost sheets would be reviewed by the Consumer Affairs Office for clarity, and approved once in final acceptable form.

Staff summary comments on the updated standby service tariff filings

The Commission's November 19, 2015 Order[152] required utilities to propose standby service tariffs reflecting the developments in the previous two-year generic docket. The Order concluded that the most effective way to develop the issues further was to take "an iterative approach—requiring the utilities to file updated tariffs that have been informed by the discussion so far."[153] Staff believes the Commission made this decision partly in recognition of the differences in the circumstances of each utility. In response, the utilities developed proposals reflecting best practices and suggestions from

[151] DOC, May 15, 2017, p. 4.
[152] *Order*, in Docket No. 15-115, issued November 19, 2015.
[153] *Order*, in Docket No. 15-115, November 19, 2015, p. 4.

the two-year generic effort, incorporating the discussions at stakeholder meetings. They revised and updated the tariffs and filed them in May 2016. Parties acknowledged that the tariffs moved in the direction of best practices and principles while also reflecting utility-specific differences.

The revised tariffs reflect utility-specific differences, which result from variations in existing utility structures relating to load patterns, rate design, customer sizes, and power supply agreements acknowledged by groups such as MCA/FE as working against a "one-size-fits-all tariff."[154] One example of a utility-specific difference is Xcel's explanation that its initial standby rate structure included an annual grace period of 964 grace hours. To completely eliminate the grace hour provision would interfere with a smooth transition between the current and proposed riders. MP pointed out that it has a unique customer mix with a handful of large customers that account for a significant portion of system load. MP's unscheduled demand charge as well as its shoulder month requirement for scheduled outages are designed to protect the Company (and other ratepayers) from the costs that could result if several large customers require standby power during higher-costs times, contributing to system peak.

In its final set of comments, the DOC recommended that the Commission approve MP's standby service tariff. It sought additional information on OTP's proposal and supported DEA's proposal to file a separate CHP standby service rate schedule, while not approving DEA's proposed Rider at this time. It also proposed certain changes to Xcel's standby service tariff proposal. MCA/FE argued that although significant progress had been made, the utilities had not provided sufficient cost justification at this time to support their standby tariff proposals and that the tariffs do not meet best practices.[155] MCA/FE's position is that there is still much to be gained from continued examination of data and cost-causation analysis. ERC's final set of comments addressed Xcel's standby service proposal only.

Given all of the developments in the record to date, the Commission is now at a decision point in a continuing process in which some judgements must be made. Whatever the Commission decides, it should recognize the need to move quickly to provide greater certainty to utilities and their customers. The standby service tariffs were filed on May 19, 2016, more than two years ago. The Commission could now decide to recognize the progress to date by provisionally establishing standby service rates, while continuing to evaluate the effectiveness of the tariffs, their cost justification and transparency. In other words, the Commission could find that parties have provided sufficient reason for moving forward with tariff approval at this time. Staff therefore recommends that the Commission consider adopting the four utility proposals for standby service tariffs, modified where appropriate, recognizing that for the most part the utilities have met the burden of explaining and supporting the structure of their proposed standby tariffs.

Procedurally, this could be accomplished by approving the standby service tariff proposals now, possibly granting requests for continued examination of data and cost causation. If the Commission decides that the utilities have not sufficiently addressed parties' comments and wishes to devote additional staff and party resources to this matter, it may wish to request additional rounds of comments and extend the review process, as proposed by MCA/FE.[156]

---

[154] MCA/FE, May 15, 2017, p. 4.

[155] MCA/FE provided Table 1 (in April 21, 2017 comments) that indicated specific areas where it believed the utilities' proposed standby tariffs do not meet best practices.

[156] MCA/FE argued that although significant progress has been made, there is much to gain from continued examination of data and cost-causation analysis.

If the Commission supports modifications, it must recognize that any changes to one part of the proposed tariffs may affect other parts of the rate structure (e.g. billing components and charges). Further, any revisions must be sent back to the utility and the revised tariffs and updated rate components will then need to be refiled for review and possible comment by the parties. If rate components change, parties will want to re-examine the impact of these changes on the rate structure as a whole.

One option for the Commission if it decides to approve the standby tariffs as proposed is to set up a process under which utilities report back in one year.[157] This approval would represent another benchmark in the development and refinement of a general approach to standby tariffs. Over the same period, the parties could be encouraged by the Commission to continue their interactions and discussions so as to reach a more common understanding of the structure of the proposed tariffs. Parties could again comment on what they see as working and what additional changes or standardization might be useful. This could include reporting on the number of customers taking service under the revised standby service as well as other information that the Commission or the parties might find valuable. Staff notes that the iterative approach taken in this docket thusfar has shown that as the utilities have explained their proposed tariffs, some of the parties' concerns have diminished, and that additional exchange of information has resulted in better understanding. Staff believes some of the remaining differences among parties might be resolved based on continued discussions.

The obvious differences in the utility circumstances suggest that initial calls for a fully standardized standby tariff, according to an agreed template applied to all of the utilities, may not be appropriate. However, utilities can work to make their standby tariffs both as similar as is feasible and as transparent as is practicable. One example of broad agreement serving the purposes of a standard approach, as well as transparency, is the adoption by each utility of a 1-2 page summary of charges table. The Commission may wish to require each utility to adopt a summary of charges table similar to OTP's.

[157] Xcel and the other utilities have acknowledged both the importance of moving ahead but also the need for continued evaluation of their standby tariffs.

Xcel's proposal for a Solar PV Capacity Credit (SCC) Rider

Introduction

The second major issue in this docket concerns Xcel's proposal for a separate solar capacity credit rider. While specific to Xcel, the proposal may have future implications for the other three rate-regulated utilities that to date have not proposed a separate solar capacity credit or rider.

Xcel's Solar PV Capacity Credit (SCC) Rider

Xcel filed a proposal for a new Solar PV Capacity Credit (SCC) Rider as part of its petition for approval of modifications to its Standby Service Rider. Currently, Xcel's solar capacity credit is available only to customers taking service under the Standby Service Rider. In its May 19, 2016 petition, Xcel proposed exempting solar and new wind customers from the standby service requirements and replacing the existing solar capacity credit with a new volumetric capacity credit. Xcel exempted solar PV and new wind customers from the current standby structure because these customers do not require "traditional" backup service (for infrequent outages) but instead have an ongoing requirement to supplement the variations in their generation.[158]

The Company's new Rider converts the present $5.15 per kW credit into a more focused peak period capacity credit of $0.07395 per kWh that is essentially a credit to billed firm demand charges. The Company proposed to apply the credit to renewable generation during the peak hours of 1:00 p.m. to 7:00 p.m. (the typical peak period for Xcel's system load requirements).[159] The proposed rider retains a monthly customer charge (similar to standby service) as a contribution to the fixed customer-related costs of the production meter for customer generation, interval metering requirements, and incremental billing process requirements.[160]

In its May 19, 2014 Order, the Commission approved a solar standby service capacity credit in recognition of the peak capacity contributions made by distributed solar generation. It set the level of the credit at $5.15 per kW[161] based on a stakeholder compromise and required updates on MISO's effort to establish a specific solar capacity accreditation value.[162] Declining to endorse a methodology, the Commission adopted the credit level based on the parties' agreement that it was generally

---

[158] Since the measured demand every month for these customers includes the backup replacement capacity for the customer's generator that occurs when solar generation is not available, there is no direct need for a conventional standby reservation demand charge. Instead, the proposed new solar rider becomes a vehicle for providing an applicable credit for the solar peak capacity contribution. (Xcel, May 19, 2016, p. 15.)

[159] Xcel, May 19, 2016, p. 14.

[160] Xcel, May 19, 2016, p. 15.

[161] Under the current Standby Service Rider, for each kW of the approved Standby Service Agreement for PV systems, $5.15 per kW demand credit (following the grace period) is applied. The solar demand credits reduce monthly billed demand charges and have no carry forward value. Eligible customers are on a demand service rate with an annual firm peak demand of at least 40 kW.

[162] See the Commission's *Order Setting Final Solar Photovoltaic Standby Service Capacity Credit, Requiring Updates, and Requiring Compliance Filing*, in Docket No. E002/CI-13-315, issued May 19, 2014, Order Point 4: Xcel shall file an update in this docket within two years of this Order on the progress at MISO to establish a specific solar capacity accreditation value and any other changes potentially relevant to the decision as to whether to update the credit. Such changes include, but are not limited to: (1) changes to base tariff demand charges in a rate case or other proceeding, and (2) material changes in avoided cost components. Xcel shall continue to file an update on this matter and the progress at MISO every 12 months following the Company's first report.

reasonable.[163] Xcel structured its proposed new solar capacity credit rider to maintain current "legacy" level ($5.15 per kW) for solar customers and recommended that the legacy level be revisited as the Company continues to look at appropriate capacity valuation, possibly coordinated with the next required annual compliance filing in Docket No. 13-315.[164] Xcel believes that maintaining the same level of the solar capacity credit in the proposed rider is consistent with the Commission's policy decision to provide a capacity credit incentive to solar generation customers.

In its May 19, 2016 petition for a revised standby service rider, the Company included compliance requirements from the Commission's May 19, 2014 Order (in 13-315). These included a discussion of solar capacity value, its accreditation status at MISO, changes to demand charges, and changes to avoided cost components. On May 19, 2017, Xcel updated this same information.[165] In both filings, Xcel noted that MISO does not have an accredited solar capacity factor. Instead, it has a UCAP capacity accreditation process for solar resources.[166] Xcel provided passages from the MISO Resource Adequacy Business Practice Manual No. 11 (effective September 2016) that describe the MISO process, and explained that MISO will review and apply subsequent revisions as needed to reflect actual resource production.[167]

Also as part of the May 2017 compliance update noted above (and as required by Order) Xcel provided updates to "any other changes potentially relevant to the decision as to whether to update the credit." In the update filing, the Company included its 2016 avoided cost of generation capacity from its 2017 Cogeneration and Small Power Production Report.[168] The Company noted that the transmission cost embedded in the current rates referenced previously in this docket is $2.74 per kW.[169] In addition, the Company noted that its most recent IRP forecasted no need for capacity until 2025. According to Xcel, system customers may not see the full benefit of the solar or wind resources receiving the credit until that time.[170] Xcel also examined other potential sources of capacity value. To provide context on the level of the credit approved by the Commission, the Company provided a table showing the base tariff demand charges established in rate cases.[171]

In its Petition requesting approval of the solar capacity credit and rider, the Company provided Table 2 (below) to illustrate that the establishment of the $5.15 per kW credit was a compromise and halfway point between the Company's position and the position of key parties in the earlier proceeding.

[163] Order, in 13-315, May 19, 2014, pp. 5-6.
[164] Xcel, May 19, 2014, pp. 8-9. The next compliance filing is due May 19, 2018.
[165] Xcel, Compliance Filing, in 13-315, May 19, 2017.
[166] Xcel explained that, at this time, MISO does not have data regarding the outcome of the UCAP capacity accreditation process for solar resources. Xcel's historic data (years 2014 and 2015) for large scale solar resources (1-2 MW) within the NSP generation portfolio would suggest a UCAP capacity accreditation of 45% to 55% of AC nameplate rating.
[167] Xcel, May 19, 2016, pp. 9-10. Xcel, May 19, 2017, pp. 2-4.
[168] Xcel, Cogen Report, Docket No. E-999/PR-17-9, filed March 15, 2017.
[169] This value represents cost incurred for transmission facilities placed in service and is not a proxy for incremental avoided transmission cost.
[170] 2016-2030 Upper Midwest Integrated Resource Plan, Docket No. E002/RP-15-21.
[171] Between 2013 and 2015, the annual on-peak demand charge increased by 10.29% and the annual off-peak demand charge increased by 6.67%. (Xcel, May 19, 2017, p. 4, Table 1.)

Table 2. Compromise on Solar Capacity Credit[172]

Line No.	Description Notes		Notes
(1)	Xcel Energy - Initial Proposed Credit (kW)	$2.00	
(2)	SRRG/DOC - Average of High and Low (kW)	$8.35	
(3)	Solar PV Credit	$5.18 ≈ $5.15	[(1) + (2)] / 2

As part of the new rider, Xcel proposed to convert the kW based solar capacity credit to a per kWh credit to reduce complexity, and to align the credit more closely with each billing period. It expects the new design to be easier for customers to understand and for the Company to administer. Figure 1 (below) is an illustration of the conversion from a kW credit to a kWh credit:

Figure 1. Conversion of Credit Basis from kW to kWh[173]

Line No.	Description Notes			Notes
(1)	Current Solar PV Credit per KW	$5.15		
(2)	Avg. No Non-Grace Period Months	10		
(3)	Annual PV Credit per KW		$51.50	(1) * (2)
(4)	Hours in a year	8760		
(5)	Peak Period Solar PV Capacity Factor	7.95%		(15.9% * 50%)
(6)	KWH Generated		696.42	(4) * (5)
(7)	Equivalent Solar PV Credit per KWH		$0.07395	(3) / (6)

The Company explained that since the present capacity credit is not directly calculated from an approved demand charge rate or from avoided cost components, it would be inappropriate to modify the credit based on updates to these values. Instead, it proposed to maintain the present capacity credit level in the short term and only modify the credit so that it is based on a more simplified peak period kWh billing quantity.

For benchmarking purposes and to provide context for the proposed credit level, Xcel provided Table 3, which compared the current solar capacity credit to the original positions of the key parties in the proceeding in which the credit was established, provided an update of the original Company position based on 2016 values, and provided various capacity credit rates based on other Commission-approved methodologies such as those in the Windsource program, the VOS rate methodology, and the tariffed cogeneration rate.[174]

In addition, as noted above, Xcel proposed to exempt solar and new wind customers from the complex grace period provision contained in the current standby rider.[175] It noted that by exempting these customers from the standby rate structure, they will be exempt from the grace hour provision and the need to execute a Standby Service Agreement.

One disadvantage of the proposed energy basis for the capacity credit is that it provides no natural limit to the capacity credit per kW of contribution to system peak capacity requirements. Without a

[172] Xcel, May 19, 2016, p. 11.
[173] Xcel, May 19, 2016, p. 11.
[174] Xcel, May 19, 2016, p. 12, Table 3.
[175] Staff notes that a grace period of two months is assumed in the derivation of the credit level.

limit, the energy-based capacity credit could exceed the value of the capacity contribution. To address this, Xcel proposed that the solar capacity credit include a seasonal credit kWh limit. The proposed rider also includes a total credit limit, linked to the fundamental basis for the credit—to offset the portion of generation and transmission peak capacity costs included in billed demand charges on the customer's bill. This second limit sets the maximum solar capacity credit as the applicable billed demand charge.[176] Xcel argued that it is important to bound the solar capacity credit by the amount of the billed demand charge, because the fundamental basis for the credit is to offset generation and transmission capacity costs included in the demand charge.

The Company proposed to implement and file both the Standby Service Rider and the Solar PV Capacity Credit Rider within 90 days of the date of a Commission order approving the Riders. The Company proposed to notify customers currently taking service under the existing Standby Service Rider (and/or with a Standby Agreement) by mail that they will be subject to new tariff terms once they are in effect.

The Company recognized that the proposed rate design revisions include significant structural changes and that there could be unintended consequences if the proposed changes are approved by the Commission. It therefore recommended an evaluation and review process. Xcel proposed that this review process be coordinated with the one-year compliance requirement in Docket No. 13-315 (due May 19, 2018). As noted, this compliance filing requires updates to factors initially used to develop the capacity credit.

Parties' comments on Xcel's proposal for a Solar PV Capacity Credit (SCC) Rider

Minnesota Solar Energy Industry Association (MnSEIA)

MnSEIA commented that Xcel's existing solar capacity credit has been a successful pilot program and warned against any pause in the implementation of the credit. It also noted the importance of retaining the credit at the interim ("legacy") rate level until a transition to a permanent credit can be made.[177]

Although MnSEIA initially supported the DOC's position on the solar credit, after the DOC's April 21, 2017 comments requiring MISO registration, it withdrew support and recommended that the Commission adopt Xcel's proposed solar capacity credit rider, including the proposed level of the credit as an interim measure.

MnSEIA's May 15, 2017 comments detailed its disagreements with the DOC interpretation of the need for MISO registration (subsequently withdrawn by the DOC), which would be detrimental to pre-existing solar facilities already receiving the capacity credit as well as future qualifying facilities.[178] MnSEIA argued that the DOC's April 21, 2017 comments were incomplete and did not propose a viable path forward, expressing concern that the DOC's proposed pause (until the qualifying facility community could develop an approach to MISO registration) might permanently end Xcel's solar credit program. MnSEIA argued that the best path forward is to retain the capacity credit at the current interim rate (as proposed by Xcel), until Xcel and MISO can find an appropriate way to register these systems.[179]

[176] Xcel, May 19, 2016, p. 15.
[177] MnSEIA, May 15, 2017, p. 11.
[178] MnSEIA, May 15, 2017, p. 7-8.
[179] MnSEIA, May 15, 2017, p. 11.

Solar Community Group (Solar Community)

On May 15, 2017, a group of solar interests filed comments in support of MnSEIA's position to adopt Xcel's proposed SCC Rider, including the equivalent interim credit rate level of $5.15 per kW. The Solar Community Group represented a significant cross section of solar energy interests, including Sundial Solar, Innovative Power Systems, Novel Energy Solutions, Kandiyo Consulting, A Work of Art Solar, All Energy Solar, Renewable Energy Services, Energy Concepts, iDEAL Energies, Solar Farm, Winona Renewable and the Union of Concerned Scientists.

In addition to supporting MnSEIA's position to approve Xcel's proposed credit and SCC Rider, the group shared MnSEIA's opposition to the DOC's comments requiring MISO registration and the concern that the DOC's recommendations could effectively terminate the solar capacity credit. The group went on to argue that the burden of registering with MISO should not fall to qualifying facilities and should be the responsibility of the utility.[180]

Solar Community Group members' separate comments

In addition to signing the letter from the Solar Community Group, Sundial Solar filed separate comments reiterating the need for Xcel itself to take primary responsibility, if necessary, for registering with MISO. It did not necessarily disagree with the concept of MISO registration, which would provide greater weight to the solar credit and encourage additional solar resources in Xcel's resource plan, but argued that this should be the responsibility of Xcel and not the qualified facility.[181]

Another member of the Solar Community Group, Novel Energy Solutions, supported MnSEIA and Sundial Solar concerning the prohibitive cost of qualified facilities registering with MISO and the need to retain the agreed upon interim solar credit.[182] A third member of the Solar Community Group, Renewable Energy Services, both rejected the DOC's MISO registration proposal and argued that the solar credit proposed by Xcel should be supported at its current level, noting that this level is quite independent of registration in MISO.[183]

A fourth member of the group, All Energy Solar, filed revised comments stating that they were in "full support" of MnSEIA's comments of May 15, 2017. They then listed a number of specific recommendations which they said "echo the sentiments within the MnSEIA comments." These included: (1) an updated solar capacity credit rider with escalation adjustments based on the CPI, (2) solar capacity credit compensation over all 12 months, (3) solar capacity credit application for both peak and off-peak daytime hours, and (4) if there is a solar credit limit, that it should be annual rather than monthly.[184] All Energy Solar noted that its contribution to Minnesota employment in the solar industry grew from three employees to over 100 in eight years. It also argued that any weakening of support for the solar industry could jeopardize gains made to date.

[180] Solar Community Group, May 15, 2017.
[181] Sundial Solar, May 15, 2017.
[182] Novel Energy Solutions, May 15, 2017, p. 2-3.
[183] Renewable Energy Services, May 15, 2017.
[184] All Energy Solar, May 15, 2017, pp. 1-3.

Two additional members of the Solar Community Group, Energy Concepts and Innovative Power Systems, filed separate comments but subsequently signed on to the comments of the Solar Community Group to support MnSEIA and Xcel's proposal for the credit at this time.[185]

City of Minneapolis

The City of Minneapolis filed comments on both August 18, 2016 and November 9, 2016. However, after further review of Xcel's proposed SCC Rider, the City indicated support for it. The City feels the new rider as proposed by Xcel "adequately compensates the behind the meter solar array owners for the increase in system capacity that is provided by such arrays, on the condition that this rider be implemented the same as any rider, without affecting the underlying tariff rules for the customers."[186]

Sam's East, Inc. and Wal-Mart Stores East (Walmart) and Target Corporation (Target)

Walmart offered support for Xcel's proposed solar capacity credit and rider while suggesting future updates to the credit may be needed. Walmart commended Xcel "for replacing the labyrinthine billing structure of the Standby Service Rider with the relatively straight-forward volumetric credit structure of the new Solar Credit Rider. If a tariff cannot readily be understood by customers paying the tariff bill, the tariff likely has failed the test of being a reasonable tariff. The new Solar Credit Rider is a substantial improvement."[187] Acknowledging that the initial solar credit resulted from stakeholder compromise, Walmart stated that it may need to be updated from time to time. Walmart nonetheless recommended that Xcel's proposed solar credit and rider be adopted.[188]

Target Corporation also supported Xcel's solar capacity credit and rider with additional suggestions. It emphasized the importance of consistency and certainty in setting solar capacity credits and recommended:

- regular updates to the solar capacity credit
- that a given year's solar capacity rate be fixed (at the level of the credit in the year the facility interconnects) for the interconnecting system for a period of 10 years
- clarification that solar plus storage systems are eligible to receive the solar capacity credit
- grandfathering existing systems receiving the $5.15 per kW for at least 10 years[189]

Minnesota Energy Storage Alliance (MESA)

MESA emphasized the issue of the integration of storage with the solar capacity credit. While not opposed to Xcel's solar capacity credit and rider, MESA argued that Xcel's proposal needed to introduce "more variable, more dynamic, time-based rates that send clear price signals."[190] In order to integrate storage, MESA requested that the Commission allow for solar plus storage in any future methodology for determining solar capacity credits because storage increases capacity value.

Parties raising questions concerning Xcel's proposal for the Solar Capacity Credit Rider

[185] Energy Concepts, April 19, 2017; Innovative Power Systems, April 18, 2017. Innovative Power Systems emphasized the importance of a fixed 10 year contract period for the solar credit.
[186] City of Minneapolis, May 18, 2017.
[187] Walmart, August 16, 2016, p. 1.
[188] Walmart, August 19, 2016, pp. 1-2.
[189] Target, April 21, 2017, pp. 1-2.
[190] MESA, August 19, 2016, p. 5.

Several parties raised questions about Xcel's solar capacity credit and rider in earlier comments filed in late summer of 2016. Some, such as iDEAL Energies and A Work of Art Solar, subsequently signed the letter of support from the Solar Community Group for MnSEIA's position supporting Xcel's solar capacity credit and rider. Others did not sign the letter of support and did not respond to the Commission's February 17, 2017 notice asking parties to provide updated comments for Commission consideration.

Metropolitan Council (Met Council)

The Met Council filed comments on May 10, 2017 reiterating their original concerns filed earlier in the docket. They disagreed that Xcel's proposed solar energy credit rider offers the same level of benefit as the terms of service for solar customers under the existing standby service rider with the solar credit. The Met Council argued that Xcel's calculation of benefits underestimates the current terms of service. It also argued that Xcel's formula for determining the credit should be used but that it should assume a full 12 months of benefit, since solar provides benefits to the grid for 12 months of the year. In addition, the Met Council argued that cost components have escalated since 2014 and in real dollars the $5.15 should be higher to reflect the same value as in the Order in Docket 13-315.[191]

The Met Council recommended that the Commission take one of the following actions:

- Reject Xcel's proposal to exempt solar from the Standby Service Rider requirements and continue to use the existing solar capacity credit and grace period for solar installations as applied under the current rider. In this scenario, grid demand should be used instead of site load demand in the months out of the grace period and the capacity credit should escalate; or

- Approve making solar exempt from the Standby Service Rider requirements and add a line to the proposed calculation that includes the benefit of a 964 hour grace period beginning June 1 or otherwise returns the approximately 30% reduction in benefit that Xcel's proposal represents.

In addition, the Met Council argued that if the credit is reduced, there may potentially be substantial economic impact on existing solar installations (and those with substantial sunk costs). For this reason, there should be protection for those who already invested. While updating the components of the credit should be expected, a materially adverse financial change in the design and benefits seems unfair to early investors and owners. Such a change without grand-parenting may in the future discourage early investment in developing technologies in Minnesota.

Department of Commerce (DOC)

In its most recent comments of May 15, 2017, the DOC recommended that the Commission move ahead in its consideration of the four standby service tariffs but wait to address Xcel's solar capacity credit rider. The DOC proposed that until the DOC and other parties have the opportunity to fully evaluate the implications of capacity registration with MISO (and have reached a resolution of the issue), the solar capacity credit rider should not be considered by the Commission.[192] According to the DOC, the increased interest in customer-sited solar generation requires additional guidance on how

[191] Metropolitan Council, May 10, 2017, pp. 1-2.
[192] DOC, May 15, 2017, p. 8.

these facilities can fairly and cost-effectively be integrated into the electric system. The DOC intends to meet with solar developers, MISO and Xcel to further discuss and resolve this issue. Once the DOC understands the MISO registration issue, it will file additional comments. As noted, the DOC's most recent recommendation is to take no action on Xcel's solar capacity credit rider at this time.

In comments filed April 21, 2017, the DOC explained the basis for its concern regarding MISO registration. It noted that the installation of a solar generation resource by a customer provides quantifiable capacity value to Xcel's ratepayers, and thus warrants a capacity credit, but only if the resource is registered with MISO for Xcel's system. If the solar facility is not registered with MISO, then it neither has the benefit of a supply-side resource nor a load modifying resource (LMR). The DOC indicated that Xcel has not registered any customer-owned generators on the Standby Service Rider with MISO and has not received any capacity accreditation for these resources. It noted that Xcel does treat the generation as a reduction to a customer's load and has included the standby load in the load obligation if the standby generator resource fails. However, Xcel is currently not able to account for any of these impacts in its capacity reserve requirement in its transactions with MISO.[193]

On July 27, 2017, Xcel submitted supplemental reply comments to the Commission regarding further discussions with the DOC concerning the MISO registration process. It explained that MISO requirements do not allow either customers or Xcel to register net-metered solar installations with MISO for capacity accreditation since Xcel does not own or control the installations.[194]

In an earlier sets of comments, the DOC supported a general methodology for determining the level of the solar credit that involves:[195]

- Estimating Xcel's avoided cost per kW-month, consisting of:
  - avoided capacity costs ($/kW/month)[196]
  - avoided transmission costs ($/kW/month)
  - line losses
- Multiplying the avoided costs by either:
  - Effective Load Carrying Capacity (ELCC), or
  - MISO-determined solar capacity value

The DOC also noted that a number of the solar developers have questioned whether Xcel's existing capacity credit should be updated since winter and summer demand rates have increased significantly since the original capacity credit was approved. Some parties recommended that contracts include the same escalator used in the VOS rate. In response, the DOC noted that it has proposed using a levelized avoided cost for a combustion turbine peaking generation plant as the basis for determining the solar capacity credit; the levelized cost already takes into account escalation factors. Thus, no additional escalation is needed. However, when the Commission takes up the issue of setting the level of the

[193] DOC, April 21, 2017, p. 8.

[194] Xcel, July 27, 2017. The respective MISO rules governing these issues are Appendix E-BTMG registration of the MISO Business Practice Manual on Resource Adequacy and the Load Modifying Resource Market Participant definition in Module A of the MISO's Common Tariff Provision. As part of its letter, Xcel provided a table showing how MISO governs registration by type of PV system/DSM, and that two MISO provisions respecting utility rights to ownership and whether the definition of a "Load Modifying Resource" is met do not allow registration.

[195] DOC, April 21, 2017, p. 7. This general methodology is explained further in earlier comments filed by the DOC on January 18, 2013, in 10-971. These comments are not part of the record in the current docket.

[196] The DOC recommended using a levelized avoided cost for a combustion turbine peaking generation plant as the basis for determining avoided capacity costs.

credit, the DOC believes it might be reasonable to update the levelized cost to reflect costs of a combustion turbine based on 2017 costs.[197]

In addition, the DOC noted that several of the solar developers argued that the benefit of solar distributed generation is not limited to on-peak periods; they assert that utilities should provide a solar capacity credit for both on- and off-peak daytime hours. The DOC responded that utilities must plan and design their systems to meet peak demand, which by definition will include and be larger than off-peak demand. The solar capacity credit should only be provided if the solar distributed generation has a positive impact on a utility's load and capability report. The addition of solar distributed generation must either reduce the amount of resources required by serving as a load modifying resource (LMR) or be counted as a resource that contributes towards peak capacity. Since off-peak daytime solar generation provides neither, the DOC argued that the Commission should not approve a capacity credit for off-peak solar generation.[198]

Xcel's response to parties comments on the Company's proposal for a new Solar PV Capacity Credit Rider

Xcel noted that some solar developers filed comments indicating that the Company's proposal undervalues solar generators' capacity contributions to the utility system. As noted, in an attempt to offer a similar level of benefit to solar customers, Xcel used the existing Commission-approved solar capacity credit level resulting from the stakeholder process that is an average of two separate values. By starting from the approved value and converting to a volumetric basis, the Company believes it has provided a relatively stable level of benefit to customers. Because the $5.15 per kW credit is an adopted settlement value approved in 2013, Xcel argued that it does not make sense to revisit the four-year-old basis of the settlement in light of current facts. Xcel believes that this fundamental flaw undercuts any proposal to modify or update the current credit.[199]

The Met Council questioned the Company's assumptions regarding the degree to which customers access grace hours. Xcel assumed that the current credit is applied ten months each year, with the other two months qualifying as grace period months. The solar capacity credit does not apply during the two grace period billing months that are typical for solar generation customers. Xcel noted that about half of the solar customers have one grace month annually and the other half have two grace months annually, making an assumption of 10.5 months a reasonable adjustment used in the conversion calculation for the proposed kWh credit basis. The change requested by Met Council would increase the proposed credit from $0.07395 per kWh to $0.07765 per kWh.

Xcel noted some commenters recommended increasing the proposed kWh solar credit by adding the difference between standard and standby reservation demand charges from grace months. However, Xcel argued that such an addition to the credit is not appropriate. The proposed credit preserves the full incremental benefit of the current solar capacity credit. The difference between standard and

[197] DOC, May 15, 2017, p. 5.
[198] DOC, May 15, 2017, p. 6.
[199] While the settlement value did not specify a methodology, the DOC at the time recommended $5.17 per kW by employing a 48.6% solar capacity accreditation, an avoided cost of a CT based on the 2013 value of $87.04/kW-yr, and an annual retail transmission related revenue requirement of $2.81/kW-month. If the DOC's calculation were updated to include a generation capacity cost from the 2017 VOS ($51.87/kW-yr), the current MISO accreditation factor of 50%, and the current annual retail transmission related revenue requirement of $2.74, the resulting calculation would be $3.73 per kW. In response to IR No. MCC-C13 in docket 10-971, Xcel stated that the 2013 value for its avoided cost is $87.04/kW-yr (or $7.25/kW-month).

standby reservation demand charges is justified only as part of the original standby service rate design that was based on continuously operated customer generation that has a low requirement for backup service.[200]

The City of Minneapolis recommended adding a provision to the proposed solar rider to clarify that the monthly billed demand is not determined according to the Standby Service Rider tariff. Xcel noted that this recommendation is not necessary because the proposed Rider, unlike the standby service rider, does not include any provision that would alter the "Determination of Demand" provision from the base tariff. The proposed Rider would be attached to a base tariff that clearly details the methodology for determining the billed demand, which the City correctly states is based on the power received from the Company rather than the total building load. Adding a billed demand provision to the proposed solar rider would unnecessarily create confusion for a determination associated with the base tariff.[201]

MESA urged the Company to include mechanisms to promote storage in its standby service modification proposal. Xcel responded that applications and technologies related to energy storage by customers is an emerging area, and system benefits from storage are unclear at this time. The Company believes there is more to learn about this new field and that this issue is not sufficiently developed to consider in this proceeding.

Xcel noted that some parties recommended that an escalation factor be added to the solar capacity credit but that the Company does not believe incorporating an escalation factor is appropriate. The DOC's recommendation on March 17, 2014 (in Docket No. 13-315) provided a reasonableness test for the $5.15 solar PV credit level based on a levelized combustion turbine (CT) cost and the Company's embedded transmission cost. The levelized CT cost already includes an escalation factor. Using these inputs, the DOC arrived at a $5.17 solar capacity cost calculation (and agreed to the $5.15 credit). The levelized CT cost is created from an escalated series of annual costs and then levelized to a single mathematically equivalent value over the same period of time. Applying an additional escalation adjustment to the $5.15 per kW credit or the Company's proposed kWh credit would effectively double count the escalation/inflation cost to the benefit of the customer with Solar PV but to the detriment of all other non-participating customers over time.[202]

Xcel believes the level of the solar credit should be revisited. Unlike interruptible load, which receives a capacity credit, the capacity of standby customers' generators is not registered with MISO, affecting the value of the capacity to the system. Xcel noted that another important consideration for determining the level of the capacity credit is the need for consistency with the embedded cost basis of applicable rates including base tariff demand charges. The capacity credit functionally applies an adjustment to kW demand quantity applied to base tariff demand charges to recognize solar PV capacity contributions that could occur during times of higher system load levels and may not otherwise result in a reduction in monthly demand charges.[203]

---

[200] Xcel, November 9, 2016, p. 8.
[201] Xcel, November 9, 2016, p. 10.
[202] Xcel, November 9, 2016, p. 12. If an annual escalation was to be added to the solar capacity credit, the current year value of the credit should be based on the current year value of CT costs instead of the levelized value. This would result in a lower initial credit but the escalation of the credit over time should mathematically be equivalent to a credit based on a levelized CT cost.
[203] Xcel, April 21, 2017, p. 5.

Target Corporation suggested the Commission fix a solar capacity credit for a period of 10 years, tied to a "vintage year" similar to the VOS methodology. Xcel responded that there are compelling reasons to avoid "locking in" values associated with a solar capacity credit, as follows:

- a 10-year fixed rate is inconsistent with traditional ratemaking practices
- fixing a long term credit to participating customers inappropriately shifts risk to the rest Xcel's customers
- fixing a credit over 10 years does not provide a means of accounting for relevant value streams, including both costs and benefits
- as stated by the University of Minnesota, "…technology is changing and […] these tariffs and associated credits and costs should be open for review. We should not lock in the market value of any given technology on a long term basis."

The Company believes its pending proposal is carefully constructed to remain consistent with base tariffs that reflect pricing objectives and to provide more direct price signals to customers. It argued that fixing customer credits based on the year they begin operating is inconsistent with these objectives.[204]

Xcel also responded that there should be no capacity credit for off-peak daytime hours since the value of the capacity credit is the driver of the peak period credit. If approved, customers will receive the full value of the capacity credit and no additional credit is appropriate. Credits for other portions of the day without other modifications to the pricing design would double count a large portion of the capacity value. Moving the credit to the off-peak daytime hours would require the peak period credit to be reduced.[205]

As part of its future compliance (in Docket No. 13-315), the Company proposed to continue reviewing appropriate solar capacity valuation. In noted that solar capacity valuation has been an active component of other proceedings, including the VOS proceeding[206] and Renewable*Connect.[207] Xcel recommended that the Commission evaluate and review proposed modifications to the Solar PV Capacity Credit Rider once the rider is in effect and at the same time it takes up the issue of solar capacity valuation. As noted, this could be coordinated with the Company's one-year compliance filing requirement on the factors used to develop the capacity credit (in Docket No. E002/CI-13-315).[208]

Staff comment on Xcel's proposal for a Solar PV Capacity Credit (SCC) Rider

The Commission should note that if it were to approve Xcel's revised Standby Service Rider without taking action on the proposed Solar PV Capacity Credit Rider, this would effectively eliminate the solar capacity credit.[209] Staff agrees with Xcel that it is important to maintain the current level of the credit at this time, and to offer the credit as part of a separate rider. Most parties in the docket appear to support establishing a separate rider, including the conversion to an energy-based credit, and

[204] Xcel, May 15, 2017, p. 2.
[205] Xcel, May 15, 2017, p. 4.
[206] Docket No. E-999/M-14-65.
[207] Docket No. E-002/M-15-985.
[208] Xcel, April 21, 2017, p. 6.
[209] Xcel's Standby Service Rider, as proposed, does not include a solar capacity credit.

maintaining the current level of the credit.[210] Xcel's position is that updating or modifying the credit based on current values would be inappropriate since it is not directly calculated from an approved demand charge rate or avoided costs components. Staff notes that without the clarification of the MISO registration issues, the DOC's initial methodology for determining the credit is not an option.

As noted by Xcel and other parties, the proposed credit level is consistent with the Commission's earlier decision adopting the settlement in Dockets Nos. 13-315 and 10-971.[211] The Commission could adopt the solar credit rider, at the interim credit level and address adjustments to the level of the credit at some later time. Most parties in the solar community support this approach, notably MnSEIA and its many members. An option for the Commission is thus to approve the level of the credit in the context of the new rider provisionally, recognizing that adjustments will be needed in the future based on an agreed upon methodology. This implies that the tariffed charge is approved subject to change on a going forward basis in the event the Commission revises the methodology for calculating the level of the credit. The solar community is waiting for greater certainty resulting from Commission action. This option allows the Commission to move forward. Taking no action on the solar capacity credit rider at this time will perpetuate uncertainty surrounding the development of solar projects.

As noted, the DOC's methodology for setting the level of the credit is not an option until unresolved questions surrounding the MISO registration process are settled. The DOC has withdrawn its MISO registration proposal and asked the Commission to take no action on the solar capacity credit rider at this time. However, as noted above, the Commission cannot approve Xcel's Standby Service Rider without taking action on the proposed solar capacity credit rider. Other parties have changed their positions on Xcel's solar credit and rider as well. Differences among the parties and changes in positions in this proceeding have been significant as understanding of the issues has evolved. MnSEIA, for example, initially supported one method for determining the credit, then after consideration provided support for Xcel's proposal, at least until DOC, Xcel and MISO can come to terms on registration.[212] Unfolding positions such as the DOC's on facility MISO registration make it difficult for the Commission to adopt a specific methodology for setting the level of the solar credit now.

Staff believes that the changing positions and lack of consensus in the record suggest that it should first adopt the solar capacity credit rider as proposed and then adopt a specific methodology for adjusting the level of the credit as part of a separate proceeding. Even if the Commission preferred to adopt a specific method at this time, the record may not support it. For example, Xcel has not proposed or committed to supporting a particular methodology and as noted the DOC has asked for additional time to develop a final position. Staff notes that the agreed level of the credit was found to be reasonable in the earlier docket and could continue as an interim level until the parties can clarify their positions on the appropriate valuation method.

---

[210] The Met Council questioned whether the proposed credit offers the same level of benefit as the terms of service for the existing standby service rider. (Met Council, May 10, 2017, pp. 1-3.)

[211] In Orders issued in both these dockets, the Commission did not adopt a methodology but instead adopted the parties' settlement that found the $5.15 per kW credit to be reasonable. The DOC's methodology for determining the credit is most fully described in comments filed on December 3, 2012 in an earlier 2010 docket (10-971). Given the passage of time and additional information available since that time, the Commission may wish to have the DOC's proposal for a credit methodology fully described and supported (including the MISO registration issue) as part of an updated record. To understand the DOC's proposed solar credit methodology, one must track back to earlier dockets and proceedings.

[212] MnSEIA, May 15, 2017, p. 11.

This option allows parties to develop their positions more clearly and provide the Commission with a better record upon which to base a decision on how to set the level of credit. It also allows more time for parties to meet and try to understand the differences in positions on this issue and to develop methodologies on solar valuation. It would also provide the Commission greater opportunity to guide the development of the record on this important issue.

If it pursues this course, the Commission could ask Xcel, the DOC and other interested parties to talk over the appropriate approach to setting the solar capacity credit and to file proposals for a methodology by May 19, 2018 (or some other acceptable date). The proposals should include a detailed explanation of the theory behind proposed valuation methods, as well as evidence supporting why such methods are appropriate. This would provide the Commission with a more complete record on which to base a decision to set the level of the credit. Xcel noted that on May 19, 2018 the Company will submit a compliance filing (in 13-315) updating components in the current credit, providing other potentially related cost components and any updated MISO accreditation information. Following this, the Commission could revisit how best to set the level of the credit in the rider. This approach has been suggested by Xcel and is acceptable to many of the parties.

Parties have also raised a number of other issues related to the application of the solar capacity credit rider. These issues have been raised but not fully briefed in this record. The Commission may wish to ask parties to address these sub-issues at the time the Commission takes up the level of the credit and any other potential adjustments to the credit or rider. Staff believes it may be premature to address these additional issues now—taking them up in the context of adopting a solar valuation method may be more appropriate. These issues include, but are not limited, to:

- If the level of the credit is adjusted, should customers with on-site solar generation currently receiving the credit be grandfathered (i.e. continue to receive the $5.15 per kW credit) for some period of time (e.g. 10 years)?
- Should the solar capacity credit be updated and if so, how often? What process should be used to update the credit?
- Should the Solar PV Capacity Credit Rider include escalated numbers so that solar capacity valuation is consistent with the value to Xcel at the moment an exchange of capacity occurs?
- Should a given year's solar capacity credit rate be fixed for customers interconnecting in that year, and if so, for what period of time (e.g. fixed for 10 years)?
- Should the solar capacity credit be kept consistent with demand rate changes?
- Should there be language in the SCC Rider to clarify that solar plus storage systems are eligible to receive the solar capacity credit?
- Should solar facilities receive credit for off-peak daytime hours, in addition to on-peak hours?
- Should the solar credit limit be applied annually instead of monthly (i.e. the monthly cap on capacity shift to an annual cap)?
- Should the credit apply 12 months of the year, without the incorporation of a grace period in its derivation?

Should all rate-regulated utilities be required to offer a solar capacity credit?

Introduction

In comments filed on August 19, 2016, MnSEIA proposed that a solar capacity credit be required for all rate-regulated utilities. In its February 17, 2017 notice seeking updated comments, the Commission asked parties whether all rate-regulated utilities should be required to offer a solar capacity credit, either as part of a standard tariff or part of a standby rider. As discussed below, the reactions to this proposal were varied but largely negative on the part of the three utilities not currently offering such a credit.

MnSEIA's proposal that all rate-regulated utilities be required to offer a solar capacity credit as part of their standby tariff or as a separate rider or tariff

MnSEIA argued that a solar capacity credit is "not an adder" but is "just compensation to a QF for the capacity it provides to the grid, especially during peak periods." It went on to liken Xcel's solar capacity credit to "a successful pilot program, and it is now time to expand their model to all of the other rate-regulated utilities."[213]

MnSEIA emphasized that solar capacity has value for a utility such as OTP, even if there is no demand for it. This is reflected in Xcel's decision to compensate for capacity even though it may not be needed until 2025. Moreover, MnSEIA emphasized that such capacity may be needed sooner in the face of unforeseen outages and unexpected increases in demand. Such capacity can respond to this demand in lieu of natural gas peaking. MnSEIA used this argument to contest OTP's absence of any capacity credit.[214] MnSEIA also noted that MP's decision to compensate only for firm power and not to compensate for non-dispatchable power is incorrect, observing that intermittent capacity is still valuable even if firm power is ideal.[215]

Sundial Solar, in comments filed August 19, 2016, stated that a solar credit similar, if not identical to, what has been outlined in the Xcel docket should be applied to all utilities.[216] Novel Energy Solutions also argued that the solar capacity credit should be extended to all rate-regulated utilities.[217] In addition, iDEAL Energies asked the Commission to approve all of the utilities' standby tariffs only if they include a solar credit program or a separate capacity credit rider.[218] All Energy Solar expressed the same view.[219]

Utility response to MnSEIA's proposal that all rate-regulated utilities be required to offer a solar capacity credit as part of their standby tariff or as a separate rider or tariff

Utilities other than Xcel were on record even before the Commission's notice as being opposed to applying a solar credit. In its November 9, 2016 comments, OTP did not support implementing a solar credit. Instead, it recommended that customers with solar generators unable to provide the generation needed at the standby service-level (a partial requirements rate), take service under a non-standby, full

[213] MnSEIA, August 19, 2016, p. 3-5.
[214] MnSEIA, August 19, 2016, p. 4.
[215] MnSEIA, August 19, 2016, p. 5.
[216] Sundial Solar, August 19, 2016, p. 4.
[217] Novel Energy Solutions, August 18, 2016, p. 3.
[218] iDEAL Energies, August 19, 2016, p. 3.
[219] All Energy Solar, May 15, 2017, p. 2.

requirements rate (such as the LGS TOD) and allow the solar generator to reduce usage during high priced times (shoulder and peak). This will produce savings to the customer similar to a solar capacity credit.[220]

In its April 21, 2017 comments, OTP argued that "existing mechanisms can be used to recognize firm and intermittent generation contributions" so that a solar capacity credit is unnecessary.[221] In opposing the adoption of a solar capacity credit, OTP indicated that it "supports using existing retail and wholesale incentive approaches that recognize firm and intermittent contribution."[222] It discussed two approaches: (1) a "retail approach" in which intermittent generators with behind-the-meter connection to the retail load taking service on an applicable retail rate schedule either use all their generation on site or export it to the grid. Under this scenario, the customer reduces retail charges for service, and (2) an approach under which the customer receives compensation via OTP's Small Power Producer Rate (less than 1 MW) or its Distributed Generation Tariff (greater than 10 MW); under this second approach, an intermittent generator sells all of its output and is compensated in a PPA based on avoided costs to the utility.[223]

In response to the Commission's notice, MP stated "intermittent generation does not fit within the scope of this standby rider, and is better addressed with other existing or future rate designs."[224] This built on MP's earlier comments that its standby service proposal applies only to distributed generation systems that run on a continuous basis and for non-emergency purposes. Solar PV customers, MP argued, can buy backup power through their standard service tariffs and existing cogeneration or distributed generation riders.[225] Furthermore, MP typically has peaks that occur on winter evenings, when solar generation is not available. MP argued it would not be appropriate to calculate a solar capacity credit within the context of a compliance filing in this docket. It noted that the Company is actively engaged in a variety of dockets related to solar generation where topics such as a solar capacity credit methodology could be better addressed.

Dakota Electric also objected to the Commission requiring all rate-regulated utilities to adopt a solar capacity credit at this time. It noted that at peak load periods, the solar production component "has diminished to near zero."[226] It commented that "MnSEIA's suggestion to develop tariffs to provide capacity credits for solar plus storage is premature."[227]

Department of Commerce (DOC)

In its most recent set of comments, the DOC stated that it had no recommendations "on whether other utilities should be required to offer a solar capacity credit at this time," pending resolution of the MISO registration issue.[228] Once the issues surrounding MISO registration are more fully understood and resolved, the DOC plans to offer a recommendation.

[220] OTP, November 9, 2016, p. 2-3.
[221] OTP, April 21, 2017, p. 2.
[222] OTP, November 9, 2016, p. 2.
[223] OTP, November 9, 2016, p. 2.
[224] MP, May 15, 2017, p. 2.
[225] MP, April 21, 2017, p. 8.
[226] DEA, April 21, 2017, p. 14.
[227] DEA, May 15, 2017, p. 8.
[228] DOC, May 15, 2017, p. 6.

The DOC's initial support for requiring other utilities to adopt a solar credit was based on the fact that the solar community supported a $5.15 per kW credit, which the Commission found to be "a reasonable, conservative interim rate."[229] Subsequently, however, the DOC raised the question of MISO treatment of the capacity and argued that the solar credit should not be implemented for any rate-regulated utility until MISO issues were resolved.[230] In its April 21, 2017 comments, the DOC recommended that, at this time, the Commission require only Xcel to continue with their proposed solar capacity credit rider after establishing a process for registering on-site customer generation with MISO.[231]

Staff comment on proposal that all rate-regulated utilities be required to offer a solar capacity credit as part of their standby tariff or as a separate rider or tariff

Staff agrees with DEA's characterization as "premature" that all rate-regulated utilities be required to adopt a solar capacity credit at this time. There are several reasons why the Commission may decide to wait to extend the application of a solar capacity credit to the other three rate-regulated utilities. First, because Xcel's credit valuation method may need to be revisited and potentially revised, it may be too soon to order the other three utilities to establish and adopt their own credit. Each of the rate-regulated utilities, apart from Xcel, expressed reasonably strong opposition to the application of a separate solar capacity credit at this time. Second, each utility, apart from Xcel, had their own reasons for opposing the credit, arising from their differing circumstances. They argued either that current tariff structure accomplishes the objectives of a capacity credit or that no capacity credit is merited based on intermittency or the relationship of solar energy to peak power demands. These comments indicate that this issue may be more complex and require further record development.

Third, the DOC's position on this issue has changed. In its most recent comments, the DOC proposed waiting until the MISO registration issues are resolved before addressing the issue of a solar capacity credit. This led the DOC to make "no recommendation on whether other utilities should be required to offer a solar capacity credit at this time," pending resolution of the MISO registration issue.[232] This lends further support to the argument in favor of not requiring the other three rate-regulated utilities to adopt a separate solar capacity credit. In sum, staff believes the record may not support ordering the other three rate-regulated utilities to adopt a separate solar capacity credit at this time.

Notwithstanding these reasons to wait, the Commission may wish to require MP, OTP or DEA to further analyze the value of solar capacity on their system, and to demonstrate that these generators are being fairly and fully compensated. One option is for the Commission to re-examine this issue at some point in the future, perhaps at the same time it evaluates a more permanent methodology for determining the level of Xcel's solar capacity credit.

[229] Order, in 10-971, issued May 13, 2013, p. 3. The full text of the Order states: "The Commission agrees with the Department, Environmental Groups, and the Solar Rate Reform Group that $5.15 per kW per month is a reasonable, conservative interim rate."
[230] DOC, April 21, 2017, p. 8.
[231] DOC, April 21, 2017, p. 11.
[232] DOC, May 15, 2017, p. 6.

Commission Decision Options

A. Xcel's Standby Service Rider

Xcel's proposed Standby Service Rider

1. Approve Xcel's Standby Service Rider as filed on May 19, 2016, with two additional revisions proposed by Xcel in response to parties' comments including a revision to allow monthly nominations made annually (as indicated in revised tariff sheets filed by Xcel on May 15, 2017), and a revision of the scheduled maintenance service limit in Xcel's Standby Service Rider from six to eight weeks in any 12 month period. (*Xcel Energy*)

2. Approve Xcel's Standby Service Rider, as filed on May 19, 2016 and revised as indicated in the Decision Option above, with one or both of the following additional revisions:

    a. Require Xcel to eliminate the grace period in the Standby Service Rider and to recalculate its Standby Service Rider rates to reflect the elimination of the grace period. (*Department, MCA/FE*)

    b. Require Xcel to change its definition of standby usage to allow for standby self-supply by creating a demand cap above which standby usage charges would be assessed, and unless this cap is exceeded, no standby charges would be assessed, even if the customer's generator was not operational. (*Department, MCA/FE, ERC*)

Flint Hill Resources (FHR) proposal for a separate standby service tariff for CHP projects 10 MW and larger

3. Require Xcel to work with FHR, and other interested parties, to address the issues raised by FHR and Xcel in this docket surrounding the need for a separate rider for customer-sited CHP projects larger than 10 MW, and if the parties come to agreement, to file a proposal for a separate rider. Require Xcel to file this proposal, or an explanation of why the parties could not reach agreement, within 60 days of the Order issuance date in this matter. The filing should be submitted under a new docket number. (*Staff proposed*.)

4. Take no action in this docket to require Xcel to file a separate standby service rider for customer-sited CHP generation facilities greater than 10 MW. (*Xcel, Department*)

5. Adopt the following set of recommendations proposed by FHR:

    a. Require Xcel to develop and propose a separate standby service rider tailored for CHP projects 10 MW and larger within 60 days of the issue date of the Commission's order in this matter.

    b. Require Xcel to incorporate the following concepts into a Company-proposed CHP standby service rider for projects 10 MW or larger:

i. Clarify and establish reasonable terms and conditions for supplementary service in lieu of requiring use of standby service for variations in generator output that occur in the course of normal operations.

ii. Allow customers to choose multiple types of standby services and clarify the terms and conditions on which they may do so.

iii. Clarify that customers choosing multiple types of standby service do not need to pay duplicative reservation charges.

iv. Establish a grace period structure similar to the existing Standby Service Rider or some other alternative suitable for CHP facilities (i.e. do not apply the proposed changes in the proposed Standby Rider to CHP projects).

v. Do not limit the duration of Scheduled Maintenance service periods for CHP projects.

6. Require Xcel to work with FHR and other interested parties in developing CHP standby service rider proposal for customer-sited generation facilities greater than 10 MW.

7. Direct the Executive Secretary to establish a comment and reply comment period following Xcel's CHP standby service rider filing in order to further develop the record on the terms and conditions of the proposed CHP standby service rider.

8. Direct the Executive Secretary to establish comment periods and other applicable deadlines in this proceeding that would allow for conclusion and implementation of a CHP standby service rider for projects 10 MW and larger by the end of 2017.

Implementation timeline and compliance filings

9. Require Xcel, within 30 days of the issuance date of the Order in this matter, to file compliance tariffs reflecting the decisions made by the Commission. The effective date for the approved changes to Xcel's Standby Service Rider will be within 90 days of the issuance date of the Commission's Order in this matter. (*Xcel*)

10. Require Xcel to evaluate the structural changes to its Standby Service Rider and to report to the Commission on its evaluation within one year of the effective date of the approved Standby Service Rider. The evaluation report should be filed in Docket No. E-999/CI-15-115. (*Xcel*)

B. Minnesota Power's (MP's) Standby Service Rider

1. Approve MP's proposed Standby Service Rider, including the revisions to the Company's Electric Service Agreement for Distributed Generation/Standby Service and Standby Service Agreement, as filed by the Company on May 19, 2016. (*Minnesota Power, Department*)

2. Require MP to revise its proposed Standby Service Rider and to make some or all of the following changes, and to refile the Rider for review and comment by parties:

a. Require MP to modify its proposed Standby Service Rider and to remove the monthly demand charge ratchet to assess unscheduled standby outage charges. (*MCA/FE*)

b. Require MP to revise its proposed Rider so that scheduled outages are not limited to shoulder months. (*MCA/FE*)

c. Require MP to provide further cost justification for the lack of differentiated on-peak and off-peak demand and energy charges for unscheduled outages. (MCA/FE)

d. Require MP to provide further cost justification for its proposal to use a monthly demand charge ratchet structure to assess unscheduled standby outage charges. (MCA/FE)

Large Power Intervenor (LPI) request for clarification of size limit

3. Accept MP's proposal to add language to its Standby Service Rider limiting the application of the Rider to customers with on-site generation of 10 MW or less, and to file the revised tariff language as part of a compliance filing for DOC review, within 10 days of the issuance date of the Order in this matter. (S*taff recommendation, MP*)

4. Require MP's to revise its proposed Standby Service Rider to add language limiting the application of the Rider to distributed generation systems with a nameplate capacity of 10 MW or less. (*LPI*)

5. Require MP to individually negotiate standby service with individual LPI members with distributed generation systems with a nameplate capacity greater than 10 MW, subject to Commission approval of the resulting agreement. (*LPI*)

Compliance filings and effective date for MP's proposed Rider

6. Require MP, within 30 days of the issuance date of the Order in this matter, to file compliance tariffs reflecting the decisions made by the Commission.

7. Find that MP's Standby Service Rider, Electric Service Agreement for Distributed Generation/Standby Service and Standby Service Agreement, as approved by the Commission, will be effective on the first day of the month following compliance filing review by the DOC.

8. Require MP to evaluate the revisions to its Standby Service Rider and to report to the Commission on its evaluation within one year of the effective date of the approved Rider. The evaluation report should be filed in Docket No. E-999/CI-15-115. (*Staff proposed*)

C. Otter Tail Power Company's (OTP's) Standby Service Tariff

1. Approve OTP's proposed Standby Service Tariff filed by the Company on May 12, 2017, including the Company's agreement (in June 9, 2017 comments) to recalculate the standby service reservation charge using OTP's generation fleet forced outage rate and to update the tariff rates based on the Commission's decisions in OTP's current rate case (Docket No. E-017/GR-15-1033). (*OTP, Department*)

2. Require OTP to revise its Standby Service Tariff filed May 12, 2017 and to make some or all of the following changes (or to provide information required) and to refile the Tariff for review and comment by parties:

   a. Require OTP to include the rate components for transmission and distribution reservation fees in its tariff. (*Department*) (**Staff Note**: The DOC has updated its position on this and accepts OTP's proposal to use percentages.)

   b. Require OTP to incorporate the average Forced Outage Rate (FOR) of its generation fleet in the determination of the reservation charge in its proposed Tariff. (*Department*) (**Staff Note**: OTP and the DOC have come to agreement on this issue as noted in the Decision Option above.)

   c. Require OTP to provide further explanation of how the Company's Standby Service Tariff will apply to standby service customers with a portion of their load served by OTP. (*Department*) (**Staff Note**: Staff believes that OTP has addressed this DOC request but the Commission may wish to confirm this with the DOC.)

   d. Require OTP to provide further cost justification for the Standby Facilities Charge in its proposed Standby Service Tariff. (*MCA/FE*)

Compliance filings and effective date for OTP's Standby Service Tariff

3. Require OTP, within 30 days of the issuance date of the Order in this matter, to file compliance tariffs reflecting the decisions made by the Commission. Find that OTP's tariff will be effective within 30 days following completion of the DOC's compliance review.

4. Require OTP to evaluate the revisions and updates made to its Standby Service Tariff and to report back to the Commission on its evaluation within one year of the effective date of the approved Tariff. The evaluation report should be filed in Docket No. E-999/CI-15-115, unless the Commission requires changes to OTP's proposed Tariff and opens a new OTP-specific docket. (*Staff proposed*)

D. Dakota Electric Association's (DEA's) Standby Service Rider

1. Approve DEA's Standby Service Rider filed on May 19, 2016. In addition, require DEA to file a new rate schedule, if it has not already done so, for consumers with on-site generation that is designed to meet member-customer electrical requirements all of the time, such as for combined heat and power facilities. As part of this new rate schedule filing, require DEA to include the necessary cost support for the rate and an explanation of how DEA incorporated fixed outage rates in its proposal for the new rate. Require DEA to file this new rate schedule within 30 days of the issuance date of the Order in this matter. (*DEA*)

2. Take no action at this time to approve DEA's proposed Standby Service Rider filed on May 19, 2016. Require DEA to file a new rate schedule, if it has not already done so, for consumers with on-site generation that is designed to meet member-customer electrical requirements all of the time, such as for combined heat and power facilities. As part of this new rate schedule filing, require DEA to include the necessary cost support for the rate and an explanation of

how DEA incorporated fixed outage rates in its proposal for the new rate. (*MCA/FE*, *Department*)

a. In addition to the above, require DEA to include in its new rate schedule filing 8,760 hour demand data (as described in Section III of MCA/FE's April 21, 2017 comments). (*MCA/FE*)

Compliance filings and effective date for DEA's proposed tariffs

3. Require DEA, within 30 days of the issuance date of the Order in this matter, to file compliance tariffs reflecting the decisions made by the Commission.

4. Require DEA to evaluate the structural changes to its Standby Service Rider and its new CHP rate schedule and to report on the evaluation within one year of the effective date of the Rider. The evaluation report should be filed in Docket No. E-999/CI-15-115, unless the Commission opens a new docket for the review of DEA's new rate schedule. (**Staff Note**: If the Commission opens a new docket for DEA's new rate schedule and proposed Rider, it will need to decide whether to require DEA to file its evaluation under the new docket number.)

E. MCA/FE proposal for a standardized approach (Model Standby Service Template)

1. Adopt the following MCA/FE recommendations:

a. Adopt MCA/FE's Model Standby Tariff as a model framework for incorporating key best practices for standby tariffs for Minnesota rate-regulated utilities. (*MCA/FE*)

b. Establish a schedule for the four rate-regulated electric utilities to provide, and for stakeholders to review and comment on, revised standby tariffs reflecting the key design elements of the Model Standby Tariff or reflecting an alternative tariff design together with an explanation of how it addresses those best practice design elements and achieves the same objective as the Model. (*MCA/FE)*

2. Take no action at this time to adopt MCA/FE's Model Standby Tariff. (*Department*, *Xcel*, *MP*, *OTP DEA*)

F. MCA/FE proposal to require utility adoption of a Summary of Charges Table

Department recommendation

1. Require the rate-regulated utilities participating in the current docket to provide a 1-2 page summary table of standby service charges and provisions, substantially similar to the table included in the proposed OTP standby tariff, for distribution to standby service customers. Require the utilities to file the summary of charges table for compliance review by the DOC, within 30 days of the issuance date of the Order in this matter. (**Staff Note**: Under this Decision Option, no formal Commission approval would be required.)

2. Require the rate-regulated utilities participating in the current docket to provide a 1-2 page summary table of standby service charges and provisions, substantially similar to the table

included in the proposed OTP standby tariff, for distribution to standby service customers. Require the utilities to file the summary of charges table within 30 days of the issuance date of the Order in this matter. Delegate to the Executive Secretary the authority to approve the content of the summary of charges tables. (**Staff Note**: Under this Decision Option, no formal Commission approval would be required.)

(**Staff Note**: The DOC did not specify a preferred compliance approach for the filing of the summary cost sheets; staff proposed the two possible compliance procedures above.)

MCA/FE recommendation

3. Adopt a Template for a 1-2 page "Summary of Standby Charges Table," substantially similar to the table included in the OTP standby tariff, to be included in or to accompany the utilities' revised standby tariffs. (*MCA/FE)*

4. Delegate to the Executive Secretary the authority to establish a schedule for the utilities to provide, and stakeholders to review and comment on, a summary of the charges imposed under their revised standby tariffs in the form of the Commission's "Summary of Standby Charges Table" template. (*MCA/FE*)

G. MCA/FE proposal to require utilities to provide further cost justification

1. Establish a schedule for the utilities to submit, and for stakeholders to review and comment on, cost justification for the charges in the utility-proposed standby tariffs, including the following:

   a. Justification of the charges imposed in the revised standby tariffs based on the proportion of cost incurred by the utility to serve the class of standby service customers who generate some or all of their own power on a non-intermittent basis, and

   b. Data reflecting annual (8,760 hours) hourly demand data for each customer with a CHP generation system over the most recent 12 months, to allow the Commission and stakeholders to review the customer-utility demand coincidence and the best billing determination for recovering utility costs (as discussed in MCA/FE's April 21, 2017 comments, section III.A.2).

2. Take no action to require all rate-regulated utilities to submit further cost justification for the charges in their proposed standby service tariffs, as proposed by MCA/FE in Decision Option G.1 a-b, above. (*Xcel, Minnesota Power, OTP, DEA, Department*)

H. Xcel's Solar PV Capacity Credit Rider

Xcel's Solar PV Capacity Credit Rider

1. Approve Xcel's Solar PV Capacity Credit Rider, as filed on May 19, 2016. Require Xcel following discussions with the DOC and other interested parties to file a proposed methodology for determining the solar capacity credit within the Solar PV Capacity Credit Rider. In this filing, Xcel should address the additional issues surrounding the solar capacity credit rider as raised by parties in this docket and listed on page 50 of these briefing papers.

Xcel should file its proposal and discussion of the additional issues by May 19, 2018, in Docket No. E-002/M-13-315 or in a newly assigned docket number. (*Xcel, MnSEIA, Solar Community Group, Renewable Energy Services, All Energy Solar*)

2. Take no action on Xcel's Solar PV Capacity Credit Rider at this time. Request that the DOC, after its meetings with solar developers, MISO, and Xcel, report back to the Commission regarding the issue of the solar capacity credit and MISO registration as raised by the DOC. (*DOC)* (**Staff Note:** The DOC may wish to update its position on this issue. If the Commission approves Xcel's proposed Standby Service Rider without taking action on its proposed Solar PV Capacity Credit Rider, this would effectively discontinue or put a hold on the solar capacity credit until a solar capacity credit rider can be approved.)

3. Approve Xcel's Solar PV Capacity Credit Rider, with some or all of the following modifications:

   a. apply an escalator, like the CPI, to account for inflation
   b. recalculate the credit to fully reflect the benefits associated with the 964 hours of grace period
   c. provide credit for off-peak hours
   d. increase the level of the credit based on updates to cost components
   e. provide a fixed credit contract rate for 10 years
   f. grandfather existing solar systems receiving the credit, at the current level of the credit for 10 years
   g. provide additional credit for solar-plus-storage systems

4. Deny Xcel's request for approval of its proposed Solar PV Capacity Credit Rider, as filed on May 19, 2016.

Compliance filings and effective date for Xcel solar capacity credit rider

5. Require Xcel, within 30 days of the issuance date of the Order in this matter, to file compliance tariffs reflecting the decisions of the Commission related to Xcel's proposal for a Solar PV Capacity Credit Rider.

6. Require Xcel to implement its proposed Solar PV Capacity Credit Rider within 90 days of the issuance date of the Commission's Order in this matter. (*Xcel*)

I. Establishing a Solar PV Capacity Credit for the three other rate-regulated electric utilities

1. Take no action at this time to require the three other rate-regulated utilities to adopt a separate solar capacity credit or rider. (*MP, OTP, DEA, Department*)

2. Find that a solar capacity credit is not justified for DEA based on the timing of solar production in comparison to both the distribution system peak and monthly wholesale power billing peaks. (*DEA)*

3. Require the three other rate-regulated utilities, which do not currently offer solar capacity credits through a separate rider, to establish a separate rider to offer such credits or to establish

a separate solar capacity credit as part of another rider or tariff. (**Staff Note**: Under this Decision Option, the Commission will need to determine an appropriate date by which utilities should file their proposed solar credit or rider proposal.)