MINNESOTA
PUBLIC UTILITIES COMMISSION

Staff Briefing Papers

Meeting Date	October 31, 2019	Agenda Item *6
Company	Xcel Energy (Xcel or the Company)	
Docket No.	**E-002/M-13-867** **In the Matter of the Petition of Northern States Power Company, dba Xcel Energy, for Approval of Its Proposed Community Solar Garden Program** **E-999/M-14-65** **In the Matter of the Petition of Northern States Power Company, doing Business as Xcel Energy, Requesting Approval of its Proposed Community Solar Gardens Program**	
Issue:	Should the Commission adopt Xcel's proposal to modify the methodology for calculating the avoided distribution cost component in the Value of Solar (VOS) rate?	
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✓ **Relevant Documents**	**Date**
Xcel's compliance filing and proposal	May 1, 2019
MnSEIA extension request	June 6, 2019
Department of Commerce	July 19, 2019

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The attached materials are work papers 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.

Relevant Documents	Date
Fresh Energy	July 19, 2019
MnSEIA	July 19, 2019
IPS Solar	July 19, 2019
Fresh Energy Info Requests 10, 18-22 (Xcel response)	July 24, 2019
Xcel's petition	August 5, 2019
MNPUC Information Requests Nos. 1 and 2 (Xcel response)	August 15 and 21, 2019
Xcel Energy	August 23, 2019
Department of Commerce	August 23, 2019
Gabriel Chan (Un of MN)	August 23, 2019
Fresh Energy	August 23, 2019
MnSEIA reply comments	August 23, 2019
MnSEIA Attachments 1 and 2	August 23, 2019
MnSEIA Info Requests Nos. 9, 13, 17 and 18 (Xcel response)	August 23, 2019
IPS Solar	August 23, 2019
Fresh Energy, supplemental comments	August 28, 2019

I. Statement of the Issues

Should the Commission adopt Xcel's proposal to modify the methodology for calculating the avoided distribution cost component in the Value of Solar (VOS) rate?

II. Background

On March 22, 2019, the Commission issued its *Order Approving Xcel's Update to the 2019 System-Wide Value-of-Solar Tariff Rate with Modifications*, in Docket No. 13-867, in part directing the Minnesota Department of Commerce (the Department) and Xcel to seek input from stakeholders regarding Xcel's proposed alternative method for calculating the VOS's avoided distribution cost component. The Commission directed Xcel to file a fully developed proposal by May 1, 2019.

On May 1, 2019, Xcel filed its proposal. On July 19, 2019, the Department, Fresh Energy, Minnesota Solar Energy Industry Association (MnSEIA), and IPS Solar filed comments on Xcel's proposal.

On August 5, 2019, Xcel filed a separate petition seeking to expedite the Commission's decision to modify the methodology for calculating the avoided distribution cost component in order that a decision by the Commission could be applied to the 2020 VOS.

On August 23, 2019, the Department, Fresh Energy, MnSEIA, IPS Solar and Gabriel Chan (University of Minnesota) filed comments in response to Xcel's petitions. On this same date, Xcel filed comments in response to parties' initial comments.

On August 28, 2019, Fresh Energy filed supplemental comments.

On August 30, 2019, Xcel filed its 2020 VOS annual update for the CSG program. The 2020 VOS will come before the Commission at a later date and may reflect decisions made by the Commission in the current case.

III. Parties' comments

Xcel filings (May 1, 2019, August 5, 2019, and August 23, 2019)

On May 1, 2019, Xcel filed a proposal for an alternative methodology for calculating the avoided distribution cost component in the VOS.[1] On August 5, 2019, the Company petitioned the Commission to revise the methodology for this component.[2]

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[1] As noted, this filing was made in response to the Commission's March 22, 2019 Order in the current docket and included a proposal that was initially filed by the Department on December 14, 2018, as part of reply comments in the 2019 VOS docket (13-867).

[2] The current methodology for calculating the distribution cost component was approved in 2014 as part of the Department's proposed VOS Methodology. (See *Order Approving Distributed Solar Value Methodology*, in Docket No. E-999/M-14-65, April 1, 2014.) The current methodology is based on actual

In both filings, the Company described the observed volatility in the avoided distribution capacity cost component and noted that it was the main driver of the significant increase in the 2020 VOS. Xcel noted that calculated under the current methodology, the 2020 VOS would be $0.2484 per kWh, which Xcel believes is highly unreasonable. The avoided distribution capacity cost alone would be $0.1373 per kWh. Xcel proposed the Commission adopt a new methodology for this component that would be based on 2 historical and 3 forecasted years of capacity spending and capacity additions. The proposed approach is reasonable because it would improve accuracy, simplify the calculation, and address observed volatility by providing increased stability in the cost input from year to year.[3]

Xcel described the proposed method as follows:

> The proposed alternative methodology is designed to measure the per kW distribution capital spend for two historic and three forecast years, and results in a positive value for the assumed avoidance of distribution project spend. The Company proposes to measure this value by identifying capital costs for capacity-related distribution projects over 5 years, then dividing those capital costs by the quantity of distribution system capacity increases over 5 years. By focusing on current and future distribution project costs, the calculation is more representative of the current distribution project cost level and distribution system needs.[4]

However, the Company went on to argue that without further modification, the proposed methodology would produce the maximum level of avoided distribution costs because it assumes that all capacity-related distribution is avoided. Xcel believes it is not clear if solar can be deployed optimally on the distribution system or achieve "critical mass" such that distribution projects can be fully avoided or deferred by the solar installed. Therefore, it proposed a 50% reduction factor reflecting a sharing of this risk between solar providers and system customers.

Xcel noted that it was required by Order to solicit feedback from stakeholders on the proposed method for calculating the distribution component (see the Commission's March 22, 2019 Order, Order Point 2). Therefore, on April 9, 2019, it sent an email message to stakeholders describing the Company's proposed system-wide avoided distribution capacity cost method and providing examples of the application to VOS vintage years 2015-2019.[5] It reminded stakeholders that the alternative method was first introduced on November 11, 2018 at a CSG stakeholder meeting, and that in preparation for the May 1, 2019 filing it would need responses

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data from each of the last 10 years and peak growth rates based on the Company's estimated future growth over the next 15 years.

[3] Xcel, May 1, 2019, pp. 4-6.

[4] Xcel, May 1, 2019, p. 5.

[5] Xcel's April 9, 2019 description of the new proposal did not include the 50% deferral reduction factor.

from stakeholders by April 16, 2019. The Company summarized these responses and attached them to the May 1, 2019 filing.[6]

In response to questions from Fresh Energy regarding how distribution investments were categorized as "capacity-related," Xcel indicated:

> Individual distribution projects costs are not broken out by type (capacity related or otherwise) in the CCOSS. Overall, distribution project costs by customer type (primary and secondary) are categorized as customer related or capacity related categories via the minimum distribution study for general rate design guidance. In this application, the term capacity is used in a more general rate design context. In the context of the VOS, the term capacity-related serves as a description to determine which project costs are deferrable by solar and this determination must be done on a project-by-project basis.
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> As per our planning process, distribution planning identifies risks on the system where we need more capacity and proposes distribution capacity projects to solve those risks. The capacity projects that distribution planning initiates are under the Electric and/or Substation Capacity Program budget types in our budget system. We were able to utilize this standard planning and budgeting process for the VOS.[7]

The Company also explained that outside of the VOS calculation, there is no business need to develop a specific category of deferrable capacity-related distribution projects. Therefore, the identification of deferrable project costs is generally based on the expertise of the distribution personnel with specialized knowledge of the system. Projects excluded from the deferrable capacity-related project list include those driven by:

- Asset health
- Equipment failure
- Large customer requirements
- Transmission requirements
- Reliability requirements.

On August 5, 2019, Xcel formally petitioned the Commission for an expedited change to the avoided distribution cost component in time for application to the 2020 VOS.

In its August 5, 2019 petition, as noted above, the Company reported that calculation of the 2020 VOS under the current method for the distribution cost component yields a levelized VOS rate of $0.2484 per kWh.[8] For reference, the levelized 2019 VOS was $0.1109 per kWh. This

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[6] Xcel, May 1, 2019, Attachment C.

[7] Xcel, May 1, 2019, p. 10, and Attachment D.

[8] On August 30, 2019, Xcel filed its 2020 VOS update. As noted, this docket will come before the Commission at a later date and will incorporate any decisions made by the Commission in the current case.

substantial increase is largely due to the avoided distribution cost input.[9] The Company argued that the avoided distribution cost value should be relatively stable from year to year.

Xcel argued that the substantial increase in the 2020 VOS rate resulting from the calculation under the current methodology would violate the state's prohibition on rates that are unjust, unreasonable, insufficient or unjustly discriminatory or preferential.[10]

The Company provided red-line modifications to the 2014 VOS Methodology (which was approved in Docket No. E-999/M-14-65) that would allow for the Company's proposed changes to the methodology. These were attached to the Company's August 5, 2019 filing.[11] As noted, the Company intends these changes for application to the 2020 VOS.

In response to the Department, Xcel indicated that it could provide the annual reporting on planned and actual distribution capacity spending and location of gardens as requested. In response to other parties, it noted that the Company has separate personnel and business areas dedicated to distribution and transmission, with independent budgets and project plans. Therefore, whether a project is driven by distribution or transmission is not relevant to the Company's cost categorization process.

In its reply comments, Xcel provided definitions of the categories used in its proposal, including: Asset Health, Capacity, Major Capacity Project, Customer Driven, and Transmission Driven.[12]

Despite MnSEIA's proposal for the use of a longer time period as the basis for the distributed capacity cost component, Xcel continued to argue for the use of 2 historical and 3 forecasted years of capacity spending and capacity additions to estimate the avoided distribution capacity cost. It argued that the Company's distribution forecast data beyond 3 years is considered a high level estimate due to the iterative nature of the distribution business, which is largely driven by the immediacy of reliability and other circumstances that reflect the practical realities of the distribution business.[13]

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[9] Under the current methodology, the avoided distribution cost value would increase from $0.0000 per kWh (in 2019) to $0.1373 per kWh (in 2020).

[10] Minn. Stat. § 216B.23.

[11] Xcel noted that these changes would modify the 2014 VOS Methodology at pages 34-36. *Staff note*: The Company did not provide comments on its specific proposal for red-lined revisions to the 2014 VOS Methodology, and other than Fresh Energy, parties did not comment specifically on the proposed red-line changes to the 2014 VOS Methodology.

[12] Xcel, August 23, 2019, pp. 2-3.

[13] Xcel argued that given the dynamic nature of the forecast beyond year 3, those projects are not suitable for the cost per kW metric. It also argued that historical data beyond 2 years is not likely to be representative of current projects. Therefore, the 2-year historical approach is appropriate because it provides a recent review of projects in an evolving distribution landscape.

Also in reply, Xcel stated that it believes MnSEIA and IPS Solar misunderstood the cost per kW input of Table 15 of the VOS calculation because adding more historical years to the calculation may actually decrease the cost per kW, since project costs generally increase over time.[14]

Department of Commerce (Department or DOC)

The Department concluded that Xcel's proposed methodology for calculating the avoided distribution cost component was reasonable and recommended approval. It noted all parties' concern with Xcel's proposal to discount the estimated per kW cost of distribution capacity by 50% and cited Xcel's response to Department IR No. 37, regarding the discount factor, as follows:

> If a project is included in the Company Avoided Distribution Cost component, customers will pay the deferral value to subscribers on each kWh of energy produced by the Community Solar Garden (CSG). If the project is not actually deferred customers will also pay upfront for the project in base rates (i.e., they will not see any deferral benefits in base rates). The Company proposes the application of a 50 percent factor to acknowledge there is some likelihood that the distribution projects will not be deferred.

Since a representative amount of distribution costs is typically included in base rates (as part of a rate case), the Department reasoned that customers will pay for some of those costs in base rates, whether or not a project results in deferral of distribution spending, unless adjustments are made in a future rate proceeding to remove the costs from base rates.[15]

The Department noted that a solar facility may not immediately contribute to avoided distribution costs. This supports some form of discount to reflect that the avoided cost will not occur in one or more years of the facility's economic life.[16] According to the Department, Xcel's proposal to discount the avoided distribution costs by 50% may or may not be ideal, but appears to be logical because it reflects the assumption that some CSGs may enable Xcel to avoid some level of distribution costs in all years, some may result in no avoided distribution costs in all years, and others may result in avoided costs in some years and not in others.[17]

The Department also noted that the value of the avoided distribution cost is intended to reflect statewide avoided costs. As a result, the specific placement of a CSG may or may not align with a location in which distribution projects may be deferred. Consequently, the Department did

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[14] Xcel pointed out that the cost per kW input, including the impact of the deferral reduction factor, is an input to Table 15 in the VOS calculation. Table 15 then calculates the impact of deferring the cost per kW one year over a 25 year period.

[15] Department, July 19, 2019, p. 3.

[16] For example, the Department believes that the avoidance of some level of distribution costs in the 20th year of a facility with a 25-year life does not warrant being paid the avoided distribution cost for the full 25 years of its life.

[17] Department, August 23, 2019, p. 3.

not object to splitting the avoided distribution cost between Xcel's ratepayers and the CSG projects as a means of reflecting the risk that distribution projects may not be deferred. However, it suggested that the Commission may wish to direct Xcel to report annually on its planned and actual distribution spending along with the placement of CSGs as way to evaluate the reasonableness of Xcel's avoided distribution cost methodology.[18]

The Department found Xcel's use of historical and forecasted capacity additions and the costs of those additions to be reasonable.[19] According to the Department, using a combination of both historical and forecasted data, rather than forecasted only, should reduce forecast errors.[20]

In its most recent Integrated Distribution Planning (IDP) report (Docket No. E002/M-18-251), Xcel provided a 5-year forecast of its distribution system. For this reason, the Department supported Xcel's proposed 3-year forecast, but did not object to including a 5-year forecast along with the 2 years of historical data. It did not recommend extending the data beyond the 5-year forecast.[21]

Finally, the Department responded to MnSEIA's proposal to expand the scope of projects considered avoided. It noted that avoided distribution capacity costs are intended to capture avoided costs due to the solar facility existing on the distribution system. Distribution projects that replace existing distribution infrastructure at the end of life, or projects done for reliability purposes but that secondarily result in increased system capacity, should not be included in the calculation of avoided distribution costs. The Department argued that if a distribution project will be done whether the solar project exists or not, the costs are not avoided.

Professor Chan et al (University of Minnesota)[22]

Chan et al noted the complexity of calculating avoided distribution costs and the many methodological alternatives. They argued that the specific objectives for this cost component,

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[18] Department, July 19, 2019, p. 3.

[19] The Department observed that the longer the forecast period, the greater the uncertainty that the forecast would be realized. In an Integrated Resource Plan (IRP), Xcel provides forecasts for a 20-year timeframe, but recommendations and Commission decisions focus most closely on the five-year action plan.

[20] The Department noted that the forecasted cost per kW is largely consistent with the historical costs as reflected in the Company's response to DOC IR No. 36. (See Department comments, July 19, 2019, Attachment A.)

[21] Department, August 23, 2019, p. 3. Although the Department discussed the possibility of using 5 years of forecasted data, it continued to recommend approval of Xcel's proposal for the use of 2 years of historical and 3 years of forecasted data.

[22] Professor Chan with University of Minnesota (Chan et al); Assistant Professor Gabriel Chan (Center for Science, Technology, and Environmental Policy and the Humphrey School of Public Affairs, University of Minnesota), Matthew Grimley and Bixuan Sun (Research Fellows at the Center for Science, Technology, and Environmental Policy, University of Minnesota) joined as co-signers of comments.

such as theoretical reasonableness, accuracy and fairness, will affect methodological choices. Chan et al were generally supportive of Xcel's proposed change in approach, but offered detailed suggestions for improvement. Their comments were directed at broadening the set of issues that the Commission may wish to consider as it reaches eventual decisions on how to calculate this value component. They argued that estimates of avoided distribution costs should be based on historic and planned cost data, drawing lessons from other Minnesota proceedings and other states, and could introduce locational differentiation by adopting factors to de-average system-wide estimates.

To deal with the problem of volatility in the current method, Chan et al proposed a fixed annual peak load growth assumption similar to the one used in Xcel's Integrated Resource Plan (IRP). They criticized the 50% deferral reduction factor proposed in Xcel's petition as untestable, argued that costs that are capacity-related should be made more transparent, and that the number of years on which the calculation is based should be analyzed to see how sensitive it is to the time period chosen. In a final recommendation for future consideration, they offered a method that averages distribution costs for the system as a whole, then adjusts for location-specific values with multipliers reflecting factors such as peak load growth and anticipated load, generation and demand changes.[23]

Chan et al observed that the fact that developers argued the VOS is too low, while Xcel argued that it is too high, suggests that the VOS results in a "negotiated financial instrument." Developers feel an incentive is required to encourage private investment in the CSG program, while Xcel seeks lower costs to the utility. This results in disagreement over the value components.

Chan et al noted that avoided costs are estimated before the fact and that costs anticipated to be avoided, may not be. They also noted that coordinating increasing distribution capacity with increasing generation capacity (either centralized or distributed) remains an unsolved problem.

Reviewing the experiences in other Minnesota proceedings and other states, Chan et al noted the wide range of methods to estimate avoided distribution costs that rely on complex system-wide simulations and forecasts. Simulation methods depend on many assumptions that make them less than transparent.[24] A 2014 survey of avoided distribution cost methods by the Mendota Group found that across 24 utilities, cost estimates range from $0 to $171 per kW-year, averaging $48.37. This wide range reflects the many different methods employed.[25]

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[23] Chan et al recognized the complexity of these alternative approaches and cited an NREL study calling for a balance between accuracy of estimates and the practicality of highly disaggregated calculations. https://www.nrel.gov/docs/fy15osti/62361.pdf For example, while an approach to calculating avoided distribution costs may be the most accurate in theory (i.e. it would come closest to the true avoided costs on average if applied year after year), the same methodology could occasionally yield unreasonable results due to large estimation errors.

[24] Chan et al pointed to a 2016 study by Cohen et al based on a simulation tool developed by the Pacific Northwest National Laboratories to study feeder distribution replacement (see Chan et al, pp. 4-5).

[25] These include system planning approaches, using combinations of historical and forecast information, marginal cost of service studies, and simple distribution cost sampling (see Chan et al's Section 2.3 for a

Chan et al described a New York example of the use of historical trends to reconstruct locational values for DERs to inform avoided distribution costs.[26] However, they concluded that "the complicated proceedings of New York demonstrate the push-and-pull between accuracy, fairness, and reasonableness that occur within a marginal costing debate. The issues are obscure but important as they represent a fundamental tension of leveraging finance, planning, and interest to create value for users of the electric grid. In New York, in particular, it appears that more accurate planning tools were eschewed in favor of more reasonable methods to third-party developers and their financiers."[27]

Chan et al suggested the following seven evaluation criteria for developing an avoided distribution cost methodology:[28]

- Take an approach more accurate than other approaches
- Incorporate specific project data to develop estimates without being dependent on individual projects; incorporate forecast information together with historic data
- Utilize publicly available data (e.g. from FERC Form 1)
- Allow for easy calculation and updating; maintain consistency with ratemaking and integrated resource planning
- Attempt to use marginal rather than average avoided costs
- Address the lumpiness of investments
- Incorporate variability associated with time/location differences

list of proposed methods for avoided transmission and distribution costs in the context of energy efficiency programs).

[26] Chan et al noted that some New York utilities forecast alternative load growth paths and their likelihood. Since these forecasts are applied to each substation independently, outliers can bias results. New York's initial attempt to de-average the marginal cost of service as part of its solar value stack compensation was found to be too complicated, highly unpredictable, and volatile. The mechanisms used depended on the top ten peak demand hours in a year, which are difficult to predict in advance and sensitive to weather shocks. Moreover, the mechanisms used, although reflecting granularity in avoided distribution costs, made it difficult for developers to make investment decisions and for utilities to make long-term planning decisions. Therefore, they did not provide proper price signals and incentives for the expansion of DERs. Given these difficulties, New York revised its approach to use 240 summer afternoon peak hours, updated every two year (bounded by a five percent change in either direction). California is also experimenting with alternative methods to estimate avoided distribution costs. (Chan et al, pp. 5-6.)

[27] Chan et al, p. 6.

[28] These criteria are based on a table outlining approaches to calculating avoided T&D costs, from the Mendota Group (prepared for Xcel's Colorado subsidiary), and cited by the Department in comments filed July 1, 2016, in CIP docket (16-541). See Chan et al, pp. 7-8, Table 1.

Based on these seven criteria, Chan et al evaluated: (1) the current method of calculating of avoided distribution cost, (2) the Xcel proposed method, and (3) the Chan et al proposed alternative.[29]

Xcel's current method

Chan et al explained that the current avoided distribution cost method uses historical cost information of the distribution system over the past 10 years in conjunction with the difference in peak load over a 10 year period. The performance of the current method is volatile due to reliance on just two data points of peak load, and ignores the changes in peak load in the interim period between the two end points. This suggests that the current methodology fails to capture the system-wide need for distribution infrastructure to meet peak load over the 10-year period.[30]

To address the high volatility in the current method, Chan et al proposed the use of a fixed peak load growth assumption, as used in Xcel's IRP. The result would be a more stable growth path.[31]

Improvements to Xcel's proposed method

Chan et al considered Xcel's proposed method for the distribution cost component as a conceptual break from the current method. Instead of relying on peak load growth and historical capacity-related investments, the proposed method applies actual and planned distribution system investment and the associated capacity that they support.[32] However, Chan et al concluded that further improvements should be made, and suggested re-examining the unsupported assumptions and opaque data sources relied on in Xcel's proposed method.

First, together with other parties, they argued that the 50% reduction factor is based on an untestable assumptions that needs additional justification. Second, they commented that the identification of distribution system investments as capacity-related should be made more transparent. Finally, they observed that the choice of a limited number of historic and forecasted years seems arbitrary, and that additional sensitivity analysis of different time

[29] These criteria were applied in a series of tables to: (1) the current VOS calculation, (2) Xcel's proposed alternative methodology, and (3) Chan et al's proposal. See Attachments A and B to these Briefing Papers for (1) and (2). For (3), see Table 4, in Chan et al, August 23, 2019, p. 17.

[30] Chan et al also noted that the 2017 and 2018 VOS calculations relied on different datasets of historic peak load than the 2019 and 2020 VOS calculations. Chan et al's Figure 2 shows this volatility in peak load. The difference between the peaks in different time periods is also highly volatile. This difference enters the current formula for avoided distribution costs in the denominator, making the component highly unstable as the number in the denominator becomes smaller relative to the numerator.

[31] Chan et al illustrated the difference between a fixed forecasted peak growth path (Figure 3-2) with the current method for estimating peak growth in the avoided distribution cost component (Figure 2).

[32] Chan et al noted that this approach is similar to that used in the Conservation Improvement Program (CIP) for avoided distribution costs.

periods should be conducted to limit the volatility of the resultant values from year to year.[33] Chan et al provided an evaluation of Xcel's proposed alternative methodology using the seven criteria noted.[34]

Chan et al also commented that Xcel's proposed methodology could be improved by making it more consistent with several other Minnesota dockets. These include: (1) Xcel's Integrated Distribution Plan (IDP), in 18-251, (2) Xcel's CIP dockets (in 16-541, 16-115, and 18-783), and (3) Xcel's Integrated Resource Planning (IRP), in 19-368. In each of these dockets, the issue of avoided distribution costs is considered.[35]

Chan et al also noted differences in the approach to avoided distribution costs across these dockets. These differences result in variations in the calculated values of avoided distribution costs, and suggest a need to link these approaches in a more formal way. The result will be increased transparency and opportunities for collaboration across these different planning processes.[36]

Chan et al alternative proposed method

Chan et al proposed an alternative method for calculating avoided distribution cost. The method (hypothetical at this point) would average costs over longer periods (multiple years) of historical and forecasted costs. However, even if the period is extended, there is an additional issue. Under Xcel's proposed method, there is a statistical likelihood that one outlier planning area could throw off the total estimate of avoided costs. To reduce this likelihood, Chan et al proposed to create locationally specific differentiation in the avoided distribution cost estimate. The alternative method would consider each of the nine planning areas characteristics so as to de-average them specific to their locational features.

Chan et al's proposed method has three steps. First, a system-wide average of avoided distribution cost over a period of time is calculated. Second, each geographic unit (such as

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[33] Chan et al, pp. 11-12.

[34] Chan et al, pp. 12-13, Table 3. (See Attachment B to these Briefing Papers.)

[35] CIP procedures for recognizing the system impact of end-use energy efficiency measures include methodologies for estimating avoided distribution and transmission costs due to efficiency measures. The IDP and IRP processes both take a systems-level perspective on investment planning to model how DERs affect the value of alternative investment strategies.

[36] In its IDP, Xcel considers avoided distribution costs mostly in potential non-wires alternative procurements. Its distribution budget is "an ongoing and iterative process" composed within 5-year cycles. Xcel acknowledged that planning tools for its distribution system are in development across the industry and will eventually incorporate more granular and probabilistic approaches than the utility uses now. The PUC ordered Xcel to provide more granular information at the distribution level for its next IDP update in 2019. Xcel's current CIP calculations estimate that energy efficiency defers $7/kW-year in distribution costs. With deferred transmission added in, the total avoided cost of T&D amounts to $9.88/kW-year. This number is lower than Xcel's prior avoided transmission and distribution costs of $36.23/kW-year for 2017. In both the CIP dockets and its current IRP, Xcel seems to use geo-targeted demand-side management as the best solution to avoiding distribution investments.

Xcel's planning areas) in the overall average should be isolated and weights created that correspond to the relative potential for solar in the geographic unit to avoid distribution system costs. These weights (multipliers) could use location-specific variables, such as locational peak load growth, anticipated load, anticipated generation growth, and demand profiles.[37] This weighting function is not fully developed. Once developed, it would be possible to set some constraints around the multipliers so that they remain reasonable and consistent over time.

A final step would be to true-up these estimates as actual data on solar development within tariff areas becomes available. Chan et al provided an evaluation of their proposed alternative method in Table 4 (see Chan et al, p. 17).[38]

Complexity of the VOS and coordination with other dockets is necessary to recognize the full system-value of DERs

Chan et al acknowledged that there may be other ways to bring new energy resources online, such as competitive procurements and program solicitations for fixed quantities of resources.[39] However, the complexity of the VOS (and other such avoided cost calculations) may be difficult to avoid in order to capture the full system-value of DER resources.[40]

Chan et al concluded that Xcel's proposed method fails to adequately capture the complexity of avoided distribution costs. Despite the time and effort needed to capture this complexity, in the long run this effort is needed. The benefits of this effort can extend to other areas of regulation including IDP, CIP and IRP. Together, these proceedings, like the VOS, seek to establish boundaries and points of negotiation concerning avoided distribution costs for DERs. Further, the IDP, CIP and IRP discussions can contribute new concepts not part of the current VOS calculation.[41]

MnSEIA (Minnesota Solar Energy Industries Association)

MnSEIA offered general comments and specific changes to Xcel's proposal. The changes included: calculating an avoided distribution cost value over a longer time period, averaged over 10 years (8 historical and 2 forecasted) instead of Xcel's 5 years. MnSEIA also

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[37] For more detail, see Chan et al, p. 16.

[38] Chan et al, pp. 14-17. See Chan et al's Table 4 based on the same seven criteria applied by Chan et al in evaluating other proposed methods.

[39] Chan et al commented that while introducing a bidding process for developers could lower costs in the short run, the level of the cap set is an unprincipled approach not based on the value of the resource to the system, and risks leaving significant amounts of beneficial new solar development on the table at a time when the economics of solar resources is rapidly changing. In contrast, while the VOS is flawed, it represents a principled approach for establishing an incentive for third parties to invest in any available solar project that creates more social value than it costs. (See Chan et al, p. 18, fn. 20.)

[40] Chan et al, p. 18.

[41] These include reliability, resiliency, avoided distribution O&M, voltage support, and power quality support.

recommended removing the 50% deferral reduction factor, using a linear regression rather than a simple average to estimate the trend in avoided distribution capacity costs, and inclusion of O&M and general plant as a category of costs avoided due to CSGs.

MnSEIA agreed with Xcel and other parties that the current formula for calculating the distribution cost component should be revised for the 2020 VOS. MnSEIA's position is based on the fact that the value for this component would be $0.23/kWh for the 2020 VOS under the current methodology.[42]

MnSEIA concluded that the methodology proposed by Xcel for determining the avoided distribution component is acceptable, but recommended four changes.[43] As noted, these changes include: (1) adding a longer data period—10 years instead of five; (2) removing the arbitrary 50% discount factor; (3) using a linear regression to determine the $/kW slope in comparing cumulative costs to cumulative capacity additions; and (4) including associated costs for avoided distribution O&M and general plant that will accompany any avoided investments in distribution plant.[44]

MnSEIA noted the VOS bill credit rate has declined and the avoided distribution capacity costs in 2017 and 2019 were calculated as a zero value.[45] Although the current formula properly recognizes that distributed solar leads to avoided distribution capacity costs, MnSEIA believes that the calculation formula is flawed and leads to a volatile and unpredictable rate, under-compensating in some years and over-compensating in others.[46]

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[42] *Staff note*: Xcel reported this number as $0.2484 per kWh.

[43] MnSEIA retained an expert, CrossBorder Energy's Tom Beach, to help facilitate the development of a new distribution capacity component. MnSEIA described his role and filed his credentials in eDockets, in 13-867, on July 19, 2019 comments: https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7b20140C6C-0000-C63F-BC26-7A4B15A9CFF0%7d&documentTitle=20197-154532-02

[44] In initial comments, MnSEIA identified two other proposed modifications in categorizing relevant capacity related distribution projects, including the inclusion of reliability projects—those projects installed principally to deal with threats to reliability, such as contingencies on the distribution system, and projects that replace existing infrastructure that fails or reaches the end of its life that should be considered to be "capacity-related" because they keep system capacity from declining (see MnSEIA comments filed July 19, 2019, p. 8).

[45] MnSEIA noted there are quantifiable benefits that accrue to the state as a result of having a competitive third-party community solar garden market in Minnesota. MnSEIA attached a report describing the benefits of Minnesota's competitive third-party community solar market. See "Minnesota's Solar Gardens: The Status and Benefits of Community Solar", by Bentham Paulos, May 2019, page 5. (MnSEIA, August 23, 2019, Attachment 1.)

[46] MnSEIA noted the 2019 VOS dropped 13% in a single year, in large part due to the zero value for the distribution capacity component. MnSEIA finds this odd given that Xcel spent $199 million on capacity-related upgrades to its Minnesota distribution system over the past ten years.

MnSEIA also argued that the reduction in CSG applications in 2019 illustrates the challenges developers face when components of the VOS inadequately capture the real-world value of the solar energy to the utility, ratepayers and society.

MnSEIA provided the table below showing the VOS avoided distribution capacity component values for the years 2014-2019, plus the 2020 component value as calculated by Xcel under the current methodology:

Table 1: Avoided Distribution Capacity Component

	Current VOS Methodology					
VOS Vintage	2015	2016	2017	2018	2019	2020*
Distribution Capacity Component per kWh	2.28	0.00	0.00	0.82	0.00	13.73

* 2020 value is calculated per the VOS methodology but not approved

It suggested that if the Commission were simply to take the mean value of the distribution component over the seven years from 2014 to 2020, it would result in a 2020 component compensation rate of $0.0252 per kWh.[47] This 2.52 cents/kWh value would be a viable interim avoided cost if the Commission is unable to determine a distribution capacity component methodology prior to approval of the 2020 VOS.

MnSEIA acknowledged that under a traditional "just and reasonable" rate analysis, the 23-cent 2020 VOS rate calculated under the current methodology might be considered excessive.[48] By contrast, it argued that the 2.52 cents/kWh value for the distribution component (the 7-year mean of the component value calculated under the current approved formula) would be within the "zone of reasonableness."[49]

In sum, MnSEIA suggested the following changes to Xcel's proposed methodology for the calculation of the avoided distribution cost component:

Eliminate the 50% discount factor. MnSEIA noted that there was almost universal opposition to Xcel's 50% discount factor. In addition to MnSEIA, Fresh Energy, IPS Solar, and Chan et al found the factor to be unsupported in the record.

MnSEIA argued that the discount factor unnecessarily reduces the distribution capacity valuation by 50%, especially given that the VOS Methodology already assumes that solar

[47] See MnSEIA's August 23, 2019 comments, page 4, Figure 2.

[48] Under the governing state statute, "Every rate made . . . by [a public utility] shall be just and reasonable." Minn. Stat. 216B.03. The statute also states that, "To the maximum reasonable extent, the commission shall set rates to encourage energy conservation and renewable energy use and to further the goals of sections 216B.164, 216B.241, and 216C.05."

[49] MnSEIA, August 23, 2019, p. 5.

projects will only be "installed in sufficient capacity to allow this investment stream to be deferred for one year."[50]

MnSEIA noted that Xcel's rationale for implementing a 50% reduction factor appears to be that developers may not know where to optimally locate their gardens. However, MnSEIA argued that Xcel currently has the information necessary to guide developers to beneficial sites. This is why the Commission initially directed Xcel to develop a viable locational component. According to MnSEIA, Xcel's justification for the 50% discount is predicated solely on the Company's inability or strategic unwillingness to accurately communicate to developers where these gardens should be situated.

Use 10 years of cost and distribution capacity data, instead of 5. MnSEIA proposed that the use of 10 years of data is appropriate for determining the distribution cost component, and represents a middle ground between the current methodology (which uses a longer-term data set of 10 years and compares today's values with numbers ten years ago), and Xcel's arbitrary 3-year look back and 2-year look forward. MnSEIA proposed the use of eight years of historical data and two years of forecasted data. MnSEIA maintained that this approach would reduce component volatility to a greater degree than Xcel's proposal, gives a better representation of avoided distribution costs over the expected solar module life, and better aligns the 25-year life of a panel with the expected distribution upgrades of Xcel's distribution system.

Use a linear regression rather than a simple average. MnSEIA proposed using linear regression analysis rather than a simple average to identify how avoided distribution capacity cost vary over time. The purpose of using a linear regression rather than a simple average is to identify the costs that vary with the kW of capacity additions over the entire period, so that the slope of the regression line captures the trend in cost for additional capacity.[51]

Include distribution O&M and general plant costs. MnSEIA proposed adding distribution O&M and general plant costs to the distribution capacity component to reflect the fact that the utility has to operate, maintain, and administer any distribution plant that it adds to its system. If distribution investments are avoided, then the associated O&M and general plant costs also are avoided. MnSEIA indicated that data on distribution O&M and general plant costs per unit of distribution plant are readily available from FERC Form 1.[52] MnSEIA's reasoning was that avoided investments in distribution plant are accompanied by lower spending over time on distribution O&M and by reduced common plant.[53]

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[50] In other words, the VOS Methodology already uses a conservative 1-year assumption to discount the value of this component. See the 2014 VOS Methodology, p. 36.

[51] MnSEIA provided an example using a linear regression estimate of cumulative costs that produced a slope of $168 per kW, instead of the $160 per kW produced using a simple average. The results were based on the five year period shown in the example.

[52] MnSEIA provided details of the O&M and general plant data in Attachment 2 to its August 23, 2019 comments.

[53] MnSEIA provided a specific decision option to address the issue of cost categorization, as follows: Add distribution O&M and general plant costs to the $/kWh distribution capacity component from FERC

Overall, MnSEIA believes that its recommendations strike a balance between the requirement to maximize small power production and cogeneration under Minn. Stat. § 216B.164, and the requirement that all rates be reasonable and consistent with the public interest under Minn. Stat. § 216B.03.[54]

Fresh Energy

Fresh Energy recommended approval of Xcel's proposed avoided distribution cost component methodology with the elimination of the 50% deferral reduction factor for the 2020 VOS and future VOS vintage years.[55] It also recommended that the Commission direct Xcel to file a categorization framework, in the form of a decision tree, showing how specific types of distribution projects will be categorized for the purpose of future VOS calculations. This would be submitted as a compliance filing (possibly within 20-30 days of the issue date of the Order in this matter).

Fresh Energy agreed with other parties that the Company has not provided sufficient data or an empirical basis to support the 50% deferral factor. For this reason, Fresh Energy recommended that the deferral factor not be adopted.[56]

Fresh Energy agreed with the Department that more empirical data supporting the factor is needed. In contrast to the Department however, it recommended that if the factor is to be considered, Xcel should provide supporting data prior to rather than after consideration. Xcel should be directed to provide supporting data, and the data should be reviewed prior to establishing a deferral factor. If the Company believes the factor is critical, it could provide supporting evidence in its next VOS update (to be filed September 1, 2020).[57]

Form 1 data. The recommended general plant loader shall be 3.3%, inflating the economic value of avoided distribution capacity by 3.3% for general plant. The distribution O&M adder would be $17 per kW-year, or $0.0117 per kWh = $17 per kW/1,452 kWh/kW-year where 1,452 kWh/kW is the assumed annual PV production. (As noted, Attachment 2 to MnSEIA's August 23, 2019 comments is the support for this decision option.)

[54] MnSEIA, August 23, 2019, p. 7.

[55] Fresh Energy supported the shift from cost per unit of peak load growth to cost per actual kW installed for determining the avoided distribution cost component. It noted Xcel's proposed methodology reduces volatility and produces a value for avoided distribution capacity costs that appears reasonable given the historical range. It did not support opening the VOS Methodology more broadly at this time, noting it would require a large investment of public resources, and could affect all of Minnesota's public utilities seeking to use a VOS tariff to compensate rooftop solar or other distributed solar customers.

[56] Fresh Energy recommended that, at a minimum, the Commission could remove the level (e.g. 50%) of the deferral reduction factor but allow for such a factor at the discretion of the Commission. In its July 19, 2019 comments (p. 3), Fresh Energy provided revisions to Xcel's red-line of the VOS Methodology that would allow Commission discretion in establishing such a factor.

[57] Fresh Energy indicated that such evidence should include an evaluation of solar project locations (both CSGs and other distributed solar projects as possible) compared to the locations of deferrable

Fresh Energy also questioned the process used by Xcel to determine which project costs were included or excluded from the calculation of the component and the Company's definitions of the capacity-related project types used in the component's calculation.[58] It noted that Xcel's system of project categorization is not used elsewhere and relies on a case-by-case determination.[59] Fresh Energy noted that some of the categorization decisions used by Xcel are subjective, including when a capacity project becomes a "major capacity project" and that it is conceivable that some projects could reasonably be put in more than one category. Fresh Energy also noted that Xcel is using internal budgets and project plans from its distribution business area to identify capacity-related distribution projects and associated costs.[60]

Fresh Energy argued that Xcel needs a more systematic approach to cost categorization that is more transparent and less subjective and clarifies where specific project types fall. By "specific project types," Fresh Energy does not mean Asset Health, Capacity, Major Capacity Project, Customer Driven, and Transmission Driven, but items such as: installing new or upgrading substations, installing new or upgrading transformers, installing new, upgrading, or extending feeders, installing or reconfiguring ties, replacing regulators, reinforcing substation equipment, etc. This would provide stakeholders with a better understanding of the specific project types (and project drivers) that the Company sees as deferrable and greater assurance that a systematic approach is being used.[61]

IPS Solar

IPS Solar agreed with other parties that the avoided distribution cost component should be reformulated to help resolve the volatility issues. It urged the Commission to support MnSEIA's proposed changes to the distribution cost component, and noted there may be future opportunities to further enhance the VOS in order to capture the full value of solar. While supporting Xcel's formula to reduce volatility, it urged accounting for distribution capacity over a 10-year period, and the inclusion of distribution investments such as asset health in the calculation.[62]

distribution investments made over the past five years and planned within the next three to five years.

[58] Fresh Energy noted that the Company's proposal relies heavily on internal decisions on how to functionalize and classify past and planned distribution infrastructure projects.

[59] Xcel, May 1, 2019, in 13-867, p. 10. Also, see Xcel response to Fresh Energy IR #22, July 15, 2019, in 13-867, p. 1.

[60] Fresh Energy found the Company's more detailed definitions of the categories of capacity-related distribution projects in reply comment to be helpful. The set of distribution project categories used to calculation the distributed cost component in the VOS is not used elsewhere and is different than the set of categories provided in the Company's November 1, 2018 IDP.

[61] Fresh Energy, August 28, 2019, p. 2.

[62] IPS Solar, July 19, 2019, p. 1.

IPS Solar found MnSEIA's proposal for calculating the distribution cost component to be incremental and defensible, while Xcel's was not. Specifically, IPS Solar supported MnSEIA's proposed changes, as follows:

- adding a longer data period
- removing the arbitrary 50% deferral factor
- including avoided investments in distribution plant (including asset health)
- using a linear regression to determine the $/kW slope when cumulative costs are compared to cumulative capacity additions

In addition, IPS Solar supported MnSEIA's suggestion that if the Commission does not adopt a new methodology for the component at this time, it could direct Xcel to use an interim value of 2.52 cents/kWh for the component in the 2020 VOS. It described MnSEIA's 7-year averaging of the distribution cost component as another defensible way to improve the VOS.

IPS Solar did not find Xcel's proposal for a 50% reduction factor credible. It argued that given Xcel's own distribution planning aimed at providing reliable power to ratepayers, there is no risk that Xcel would be unable to target planned distribution upgrades and determine the size/type of solar projects that would defer those upgrade investments.[63] It argued that Xcel clearly controls both where and how CSGs are beneficially developed in their distribution network. Xcel ratepayers therefore are receiving the full distributed capacity value, not 50%. It argued that for Xcel to argue otherwise contradicts the Company's own distribution planning aims of providing reliable power to ratepayers.

IPS Solar believes when located properly, the solar energy alone from a CSG can reduce the cost of distribution upgrades to avoid overloads from pockets of new peak loads. It argued no one is preventing Xcel from working with CSG developers to create DER projects that maximize the avoided costs of distribution, nor is anyone preventing Xcel from clustering 1 MW (non-co-located) CSGs that defer feeder and possibly sub-station upgrades. Therefore, Xcel's attempt to discount the value component by 50% lacks credibility.

IPS Solar also noted that the information necessary for the Commission to evaluate the distribution capacity element is not restricted to this docket. It argued that information from Xcel's IDP, in Docket No. E-002/CI-18-251, shows Xcel's ability to map needed distribution upgrades and to make a comparative cost analysis of non-wires and traditional upgrades. The Company's IDP also discusses the emerging role of DERs, where solar in combination with

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[63] IPS Solar noted that in framing the Xcel IDP, the PUC staff stated, "Xcel shall provide a detailed discussion of all distribution system projects in the filing year and the subsequent 5 years that are anticipated to have a total cost of greater than two million dollars. For any forthcoming project or project in the filing year, which cost two million dollars or more, provide an analysis on how non-wires alternatives compare in terms of viability, price, and long-term value." In its IDP, Xcel lists 39 distribution upgrades by location that meet this cost threshold. It is likely that a lower cost threshold would enlarge the list of upgrade locations overall and increase the number of less complex upgrades. Whatever the final list size it is clear that Xcel is able to map the beneficial locations for CSGs on its distribution network.

battery storage, and targeted energy efficiency and demand response, can defer and even avoid distribution investments.

IV. Staff discussion

Introduction

The Company, the Department and parties appear to agree on the need to establish a revised method for determining the avoided distribution cost component for the 2020 VOS. There is consensus that the current method can lead to volatile and in some cases extreme results. There is also recognition that calculating avoided distribution costs is complex and requires making assumptions on which resulting estimates depend.

Parties proposed at least four changes to Xcel's proposed methodology: (1) eliminating the 50% deferral reduction factor, (2) revising the time period over which costs are calculated, (3) revising and clarifying the cost categorization process, and (4) considering the use of linear regression analysis in place of a simple average of avoided annual distribution costs.

Below, staff discusses whether Xcel's proposed methodology is sufficient, or revisions are needed. Also considered is whether the proposed methodology with revisions should be applied retroactively to the 2019 VOS, or if the Commission should retain the current methodology for now and use a simple average of past values based on the current methodology for the 2020 VOS. After reviewing these options, staff discusses whether it is necessary to permanently modify the 2014 VOS Methodology at this time, or whether the Commission could move forward by applying an interim number based on a revised methodology.

The 50% deferral reduction factor

As noted, Xcel included a 50% deferral reduction factor as part of its proposed methodology for determining avoided distribution costs. Xcel justified the factor by arguing "it is not clear if solar could be deployed in specific places on the distribution system or achieve critical mass such that the distribution projects could be avoided or deferred by the actual solar installed."[64] Because some CSG projects will not be optimally sited for avoided distribution costs, Xcel proposed the 50% deferral factor as a way of sharing this risk between developers and shareholders.[65]

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[64] Xcel, May 1, 2019, p. 5.

[65] The Commission's March 22, 2019 Order, in 13-867, Order Point 2, required the Department and Xcel to solicit the opinions of the stakeholders regarding Xcel's proposed method for calculating the VOS avoided distribution cost. This was to be followed by a more fully developed proposal filed by May 1, 2019. On April 9, 2019, Xcel sought input from stakeholders by providing a summary of the alternative proposal, including sample calculations for the previous five years. However, the Company's summary of the new methodology presented on April 9 did not include the 50% deferral reduction factor.

The Commission may want to consider whether Xcel's rationale constitutes sufficient reason for such a significant change in the methodology. This question is broadly reflected in the skepticism of the parties. Even the Department, which does not oppose the 50% deferral factor, commented that it "may not be ideal."[66]

All of the other parties objected to Xcel's proposed 50% deferral reduction factor, arguing that it is arbitrary, unsupported and an unnecessary step in the proposed calculation. Fresh Energy recommended that the factor be removed from the calculation until more data and analysis in support is available. Chan et al commented that the 50% deferral factor is based on untestable assumptions warranting further justification. IPS Solar argued that Xcel already has information allowing it to map beneficial CSG locations and that the Company's active efforts to map these locations undermines the idea that there are risks of not achieving avoided distribution costs, under-cutting the risk-sharing rationale for the 50% deferral factor.[67]

One of the Department's arguments in support of the deferral factor is that the CSG will not provide the avoided costs for the full 25 years of the project. MnSEIA noted that the existing VOS Methodology already makes the conservative assumption that solar installations will allow an investment stream to be deferred for only one year, and then amortizes this avoided cost over the 25-year project life.[68] Fresh Energy noted that the Company's concerns about solar placement appear limited to observations about their CSG fleet, while changing the VOS Methodology could also affect rooftop and other distributed solar customers in the future.

The Department supported the deferral factor on slightly different grounds, noting that it can reflect the fact that costs may be avoided in some years but not all. It also noted that some amount of distribution costs are always included in base rates so whether a project results in a deferral of any distribution spending or not, customers will be paying for some of these costs. Even as the Department supported the 50% deferral factor, it recommended that empirical data to support the factor be filed after-the-fact. By contrast, Fresh Energy suggested that such empirical data should be required prior to adoption.

Based on the evidence in the record to date, showing broad opposition to the 50% deferral factor, the Commission may wish to seek further empirical support and justification from Xcel prior to considering adoption. This empirical support has been suggested by all parties, including the Department.[69] Regardless of what the Commission chooses to do with the 50%

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[66] DOC, August 23, 2019, p. 3.

[67] Staff believes that at this time developers cannot rely on either the Company's Hosting Capacity Analysis or IDP for information on where gardens can be cost effectively sited in order to avoid distribution capacity costs.

[68] 2014 VOS Methodology, p. 36. The Commission may wish to ask MnSEIA to further explain their argument concerning this assumption.

[69] The Department recommended that the Company report annually on its planned and actual distribution spending, as well as the placement of CSG projects, in order to help evaluate the reasonableness of the avoided distribution cost methodology. Staff is unsure if this annual reporting would be part of the VOS update filing submitted by Xcel on September 1, or part of some other

deferral factor, it could require Xcel to file empirical support either as part of a compliance filing or as part of the Company's 2021 VOS update filing (September 1, 2020).

Xcel's proposal for the calculation of avoided distribution costs is new and not part of the approved 2014 VOS Methodology, nor is the proposed 50% deferral factor. Although Xcel's proposed methodology is an improvement, parties have proposed significant changes. While there may be support for the use of Xcel's general five-year alternative, the Commission may decide not to take the further step of applying a 50% deferral reduction factor until there is additional evidence to support the concept and it application. Another option, if the Commission found it appropriate, would be to apply a deferral factor (or a reduced deferral factor) temporarily while empirical data is collected and evaluated.

Time period for determining avoided cost value component

The Commission will need to decide if the 5-year average (2 years historical and 3 years forecasted) proposed by Xcel is sufficient to calculate the avoided distribution cost component. Xcel acknowledged that this period might be longer, but responded that going back more than 2 years will capture data unrepresentative of current conditions. Xcel also argued that forecasting more than 3 years forward confronts the uncertainty resulting from the iterative and dynamic changes that affect the distribution system and budgeting process, as they evolve over time.

Despite Xcel's position, parties have raised concerns about whether longer time periods would produce more stable and reliable estimates of avoided distribution cost.

MnSEIA offered a specific decision alternative based on a 10-year calculation. It cited the NERA (National Economic Research Association) methodology, which uses 10 years of historical spending on distribution investments and a 5-year forecast of increases in investment. MnSEIA therefore recommended in reply that the Commission explore the use of more than 5 years of data, proposing a 10-year period with 8 historical and 2 forecasted years. Among the reasons it gave were robustness and reduced volatility, a better representation of avoided costs over the project life of 25 years, and that deferred distribution costs may not occur until later points in project life.

A longer time period was also supported by Chan et al and IPS Solar. Chan et al argued that longer periods could limit the volatility of avoided distribution values from year to year. IPS Solar fully supported MnSEIA's 10-year proposal. The Department, while supporting Xcel's position, seemed willing to accept as much as 5 years of forecasted data for the calculation. Fresh Energy took no explicit position on this issue, and recommended the Company's proposal, including the time periods for the analysis.

The Commission may wish to give the argument in favor of longer time periods careful attention. The current methodology for calculating the component contained in the 2014 VOS

compliance filing.

Methodology is based on a 10-year period but calculates the avoided distribution costs from only two data points over the 10-year period. Chan et al showed that using two points of peak load 10 years apart ignores considerable fluctuations in the interval between them.

Staff notes that as observed by Xcel, using more years of historical data could actually reduce the cost per kW of avoided distribution cost.[70] However, to staff's knowledge, the effect of a longer historical period, such as 8 or 10 years of historical data, has not been fully analyzed in the record.

Staff agrees with Xcel that the use of an 8- or 10-year historical period is complex. In response to a MnSEIA IR No. 17, Xcel explained that it was not willing to provide the necessary data to calculate the avoided cost component based on 10 years of historical data because it would be time consuming and speculative. In reply comments, Xcel reasserted its position in favor of 2 historical and 3 forecasted years.[71] Therefore, the Commission may find that both insufficient record development and continued disagreement prevent it from adopting MnSEIA's proposal to use an 8-year historical and 2-year forecasted timeframe for the 2020 VOS at this time.

Parties have noted the 5-year time period in the IDP docket over which distribution costs are forecasted.[72] As Chan et al noted, the 5-year cycles employed in the IDP docket (18-251) may be a useful template for the VOS avoided distribution cost calculation, especially as estimates using non-wires alternatives (NWA) become more granular after 2019.[73] Like Chan et al, the Department also noted the use of 5-year planning period cycles in the IDP docket as a possible example for the VOS calculation.

In short, the 5-year forecast in the IDP discussed by Chan et al and the Department might be linked more clearly to the VOS process. For this reason, the Commission may wish to consider using Xcel's 3-year forecast for the 2020 VOS calculation, and could consider a 5-year forecast for the calculation of the VOS in future years in order to coordinate it with the IDP forecast, if the future record supports the change.

Cost categorization

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[70] Xcel, August 23, 2019, p. 4.

[71] See Xcel response to MnSEIA IR No. 17, filed August 23, 2019, p. 2.

[72] *Order Accepting Report, and Amending Requirements*, in 18-251, issued July 16, 2019. Order Point 3, in part: "Xcel shall provide a 5-year Action Plan as part of a 10-year long-term plan for distribution system developments and investments in grid modernization based on internal business plans and considering the insights gained from the DER futures analysis, hosting capacity analysis, and non-wire alternatives analysis. The 5-year Action Plan should include a detailed discussion of the underlying assumptions (including load growth assumptions) and the costs of distribution system investments planned for the next 5-years (expanding on topics and categories listed above). Xcel should include specifics of the 5-year Action Plan investments...".

[73] Chan et al describe the IDP as a process in development, which when updated in November 2019 will incorporate more detailed information. (Chan, August 23, 2019, p. 13.)

Parties and Xcel disagreed about the categories and transparency of the process used to determine the appropriate cost to include in the determination of avoided distribution costs. Xcel noted that the system used to categorize project costs is not used elsewhere and relies on a case-by-case determination. Xcel explained that it used budgets and project plans from its distribution business area to identify capacity-related distribution projects and associated costs.[74]

Parties, including Fresh Energy, MnSEIA, IPS Solar and Chan et al, questioned the transparency of the process used by Xcel to select projects and cost categories.

As part of their initial comments, Fresh Energy and MnSEIA sought more information on the process. Fresh Energy sought details on the classification of distribution project costs, while MnSEIA criticized the exclusion of cost categories such as reliability projects.[75] Fresh Energy emphasized the need for a classification framework such as a decision tree, while MnSEIA emphasized specific project categories such as O&M and general plant. In reply, Xcel addressed some but not all of these concerns.

Despite the information provided by Xcel in reply, Fresh Energy found Xcel's categorization decisions subjective, and noted that certain projects could be put in more than one category. An example is the definition of a "major capacity project."

Given these concerns, Fresh Energy recommended that Xcel be directed to develop a clear categorization framework, based on a decision tree that codifies how Xcel will determine where specific project types fall.[76] A future compliance filing with this information would provide stakeholders with a better understanding of the specific project types (and project drivers) that the Company sees as deferrable, and greater assurance that a systematic approach is used. Staff supports Fresh Energy's recommendation as a pathway to making the process more transparent and less seemingly subjective to parties. A decision tree framework would also increase the analytical rigor of the process and could be helpful in other dockets in which cost-categorization is needed.

In its initial comments, MnSEIA noted that Xcel's proposed method excluded certain projects from the list of those related to capacity-related distribution. It argued that a broader set of

[74] Xcel's rationale for how distribution cost categories are determined or included as distribution capacity-related is included in the Company's August 23, 2019 reply comments and in its response to Fresh Energy IR No. 10. The Company stated that projects excluded from the deferrable capacity-related projects list are those driven by: asset health, equipment failure, large customer requirements, transmission requirements, and reliability requirements.

[75] See Xcel responses to MnSEIA IR Nos. 10, 18-22, filed July 24, 2019.

[76] The Commission may wish to ask Fresh Energy for additional details concerning the use of a decision tree as an aid to analysis in this case. By "specific project types," Fresh Energy does not mean Asset Health, Capacity, Major Capacity Project, Customer Driven, and Transmission Driven, but items such as: installing new or upgrading substations, installing new or upgrading transformers, installing new, upgrading, or extending feeders, installing or reconfiguring ties, replacing regulators, reinforcing substation equipment, etc.

distribution projects should be included, including more capacity-related projects and investments in distribution plant. Chan et al discussed the relevance of other dockets, and noted that compared to other dockets, the VOS process does not account for avoided distribution costs due to O&M, voltage support, or power quality support.[77] IPS Solar called for the inclusion of additional costs, such as asset health.

MnSEIA's specific recommendation for the 2020 VOS was that Xcel be directed to add distribution O&M and general plant costs to reflect that the utility has to operate, maintain, and administer any distribution plant that it adds to its system. MnSEIA argued that if distribution investments are avoided, then the associated O&M and general plant costs are also avoided. It indicated that data on distribution O&M and general plant costs per unit of distribution plant are readily available from FERC Form 1, and provided a specific decision option for adoption.[78] Staff suggests that rather than take a piecemeal approach to this issue, the Commission could ask Xcel to develop a more comprehensive decision analysis of cost categorization as proposed by Fresh Energy.

In any event, how avoided distribution costs are categorized may continue to be a source of disagreement, not unlike the disputes that surround class cost of service studies. Part of the reason staff supports a decision analysis of the sort proposed by Fresh Energy is to bring greater clarity to the issue. This is the first time Xcel has gone through the distribution cost categorization process for the VOS. It also is the first time parties have reviewed and commented on Xcel's process.

As noted, while Fresh Energy and Chan et al provided comments on the conceptual framework for improved cost categorization, MnSEIA and IPS Solar recommended specific and immediate changes for application to the 2020 VOS. As noted, MnSEIA proposed that O&M and general plant costs should be added to the list of costs included in the calculation of avoided distribution costs. Before making a decision to include these costs, the Commission may wish to seek further discussion of this issue at the meeting on October 31, 2019. After hearing from parties, the Commission could then decide whether additional vetting of the issue would be helpful, and/or if additional analytical work is needed prior to making a decision.

However, the Commission will need to make a decision on this issue for the 2020 VOS. Staff sees the following options:

- Accept Xcel's categorization of costs for purposes of calculating the 2020 VOS but direct Xcel to develop a categorization framework as proposed by Fresh Energy and file it as part of a compliance filing within 20-30 days of the Order in this matter.

- Either direct Xcel to include O&M and general plant costs in the list of costs to be included in the calculation of avoided distribution costs for the 2020 VOS, or move

[77] Chan et al, August 23, 2019, p. 19.

[78] MnSEIA provided details of the O&M and general plant data in its August 23, 2019 comments, Attachment 2.

forward with the cost categorization as proposed by Xcel and seek additional examination and vetting of the issue by Xcel and stakeholders going forward.

- Given that Xcel has expressed a willingness to work with the Department to identify and provide further information on the Company's cost categorization process, accept this offer and direct Xcel to extend it to other stakeholders as well. The Commission could ask Xcel to provide additional information and transparency on its system of cost categorization by meeting to discuss the issue with the Department and stakeholders. This is especially important given the fact that Xcel's cost categorization system is not used elsewhere and relies on case-by-case determinations that are made by the Company.

Linear regression analysis

MnSEIA proposed the use of regression analysis in place of a simple average in the determination of the avoided distribution cost component. MnSEIA suggested that the purpose of using a linear regression in place of a simple average is to identify the costs that vary with the kW of capacity additions over the entire period of study.[79] In the example provided by MnSEIA in reply comments, under a linear regression approach, the resulting estimate of marginal avoided distribution costs per kW was $168, compared to $160 per kW using a simple average.[80]

Xcel was unable to respond directly because MnSEIA's specific proposal was submitted as part of reply comments, and therefore Xcel has not responded on the record. Neither did other parties; although IPS Solar supported the proposal as part of its general endorsement of MnSEIA's decision options.

Given the lack of comments and a full understanding of this approach, the Commission may wish to seek additional record development before directing Xcel to apply a linear regression in

[79] MnSEIA recommended the linear regression approach based on reference in their July 19, 2019 comments to the approach taken by the NERA, which uses a regression method with 15 years of data to estimate long-run avoided distribution costs. NERA used the slope of the regression line to estimate the marginal costs of distribution investments associated with changes in peak demand. (MnSEIA, July 19, 2019, p. 7).

[80] MnSEIA, August 23, 2019, pp. 6-7. Also, as part of a permissible ex parte communication, staff asked MnSEIA to explain the steps used to apply the linear regression method together with an example using the Company's 5-year time period for determining cumulative costs and capacity additions, including the cost per kW for the 2020 VOS. MnSEIA responded by explaining these steps and producing an example. The steps were first to assemble data on distribution investments and capacity additions in each year, then to add these two series to produce cumulative totals, then to estimate cumulative investments as a function of cumulative capacity in a linear regression analysis. The slope of the estimated line is the marginal avoided cost of distribution in dollars per kW. MnSEIA produced a spreadsheet using the five years from 2016-2020 as an example but indicated this is the same example provided in August 23, 2019 comments, p. 7. (See PUC Permissible Ex Parte Form, in 13-867, filed October 11, 2019.)

place of a simple average. If the Commission wishes, it could hear more from parties on this issue at the meeting on October 31, 2019.

Procedural paths

As discussed above, the Commission will need to decide: (1) whether to adopt Xcel's proposed methodology, as filed, or with one or more of the proposed changes,[81] (2) whether to apply Xcel's proposed method (with any revisions) to re-calculate the 2019 avoided distribution cost component and 2019 VOS as proposed by MnSEIA, (3) whether to adopt MnSEIA's proposal to use a mean value of historical years for the 2020 VOS in place of revising the current methodology,[82] and (4) whether to consider permanent changes to the 2014 VOS Methodology at this time through the adoption of red-lines.

The Commission will also need to decide whether: (1) to require additional compliance filings and annual reporting, and (2) to direct further examination and vetting of issues through written comments, supporting data, and/or further stakeholder discussion.

Staff notes that MnSEIA's recommendation to re-calculate the 2019 VOS would apply to a VOS vintage rate table already established in tariff. As such, any modifications, whether applied prospectively or retroactively, might result in a number of difficulties, including substantial administrative effort and confusion among developers and customers. If intended to apply retroactively, such an action might be contrary to statute. For these reasons, staff suggests the Commission seek further clarification from both MnSEIA and Xcel prior to considering this proposal.

MnSEIA proposed that if the Commission is not ready to adopt a new methodology at this time, one option would be to adopt an average value for the 2020 VOS based on values calculated under the current methodology. Specifically, MnSEIA proposed that the Commission consider the option of using $0.0252 per kWh, the result of averaging the distribution component over 7 years from 2014 to 2020. MnSEIA noted that, in fairness, developers accepted a zero value for the avoided distribution cost in 2017 and 2019. Staff notes that this option would use values generated under the currently approved 2014 VOS Methodology. However, apart from MnSEIA (and IPS Solar's general support of MnSEIA's decision options), no other party discussed this proposal.

If the Commission finds that there is insufficient support to adopt Xcel's proposed methodology as red-line changes to the 2014 VOS Methodology at this time, it might consider adopting an

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[81] These changes include: elimination of the 50% reduction factor, use of a longer time period, different cost categories, and use of linear regression. In addition, Chan et al proposed that the Commission consider a number of longer-term design issues. These include lessons from other dockets and other states, long-term peak load growth assumptions, and others. If the Commission wishes, it could ask Xcel to work with the Department and stakeholders to analyze and develop these longer-term program design proposals.

[82] MnSEIA proposed that the mean value of the distribution component over the 7 years from 2014 to 2020, or $0.0252 per kWh, be used as an interim value for the 2020 VOS.

interim value based on a revised methodology without making permanent changes to the 2014 VOS Methodology. If the Commission finds it reasonable to adopt an interim value, possibly based on some version of Xcel's proposed 5-year average approach (with or without the 50% discount factor), it could then use compliance filings and stakeholder discussions to consider adjustments as experience accumulates. Once the Commission and Department are comfortable formally introducing changes to the 2014 VOS Methodology, they could do so. The Commission should note that although Xcel's petition included red-lines to the 2014 VOS Methodology, the Company also indicated that it is was open to any procedure that enables a timely fix so as to reasonably adjust the 2020 avoided distribution component.

A procedural path based on an interim and more incremental approach would also be consistent with other parties' calls for caution respecting permanent changes in this value component, and for longer-term thinking about its design as suggested by Chan et al. Fresh Energy noted that any permanent changes to the 2014 VOS Methodology will have impacts on future applications of the VOS tariff and would apply to all solar facilities, including rooftop PV. While the VOS Methodology is currently only in use for Xcel's CSG program, all of Minnesota's public utilities can in principle seek to use a VOS tariff based on the 2014 VOS Methodology to compensate any rooftop or other distributed solar facility.

Fresh Energy also commented that there is no reason that permanent modifications to the 2014 VOS Methodology need to entirely replace the current method for determining the avoided distribution cost component. It noted that for multiple components of the VOS, the Department provided more than one acceptable method.[83] In the interest of flexibility for future VOS applications, Fresh Energy suggested that the Commission may want to consider preserving the current system-wide and location-specific methods as options for calculating avoided distribution capacity cost.

If the Commission decides to make permanent changes to the 2014 VOS Methodology by adopting red-line changes, both Fresh Energy and Xcel have provided optional language. However, there was little discussion of these red-line proposals in the record (and these parties' positions on red-lines may have changed). Xcel did not discuss its specific red-line changes in detail but simply included them as an attachment to its August 5, 2019 petition. Other than Fresh Energy, parties did not specifically comment on the proposals for red-lines to the 2014 VOS Methodology.

A final reason not to move too far in the direction of permanent change is that some parties, notably MnSEIA, after raising objections in their initial comments, significantly adjusted their positions in final comments. This may have been because parties felt the need to come to agreement once it was clear that the 2020 VOS calculated under the current methodology was unreasonably high.

If the Commission finds Xcel's proposed methodology is theoretically sound, analytically rigorous, transparent, and supported in the record, it may wish to permanently revise the 2014

[83] This applies to the components for: avoided fuel cost, hourly PV fleet production, and avoided distribution capacity.

VOS Methodology. Staff notes that Xcel filed its petition to modify the 2014 VOS Methodology in both the CSG docket (E-002/M-13-867) and the VOS docket (E-999/M-14-65). Parties on both service lists were notified of the Commission meeting on October 31, 2019.[84] Therefore, staff believes the Commission could make permanent changes to the 2014 VOS Methodology as part of its decision in this matter.

However, if permanent changes to the 2014 VOS Methodology are made, they should be narrowly crafted—as recommended by both Xcel and Fresh Energy. Changes should not only be crafted narrowly but should accurately reflect the Commission's decisions. To assure this outcome, the Commission should direct Xcel to make a compliance filing showing the changes in red-line that reflect the Commission's decisions.

Additional filing requirements

Parties have suggested a series of additional reporting requirements.

Based on its recommendation to adopt 50% deferral factor, the Department recommended an annual reporting requirement. The Department proposed that Xcel be directed to report annually on its planned and actual distribution spending along with the placement of CSGs as way to evaluate the reasonableness of Xcel's avoided distribution cost methodology.[85] Fresh Energy concluded evidence was necessary prior to adopting the 50% deferral factor and that this evidence should include an evaluation of solar project locations (both CSGs and other distributed solar projects if possible) compared to the locations of deferrable distribution investments made over the past five years and planned within the next three to five years. If the Commission decides to require this information of the Company, staff suggests that it seek further clarification from the Department and Fresh Energy on when it should be filed and how it should be evaluated. Fresh Energy indicated that the required supporting evidence could be filed as part of the Company's 2020 VOS update compliance filing (September 1, 2020).

In addition, Fresh Energy proposed that the Commission direct Xcel to file a categorization framework, or decision tree, showing how specific types of distribution projects will be categorized for the purposes of future calculations of the value of solar avoided distribution capacity component. Regardless of the specific decisions surrounding cost categorization, the Commission may wish to require this compliance filing in order to increase the transparency of the process.

Consistency in the approach to calculating avoided distribution costs across PUC Dockets

Chan et al commented that potential improvements to Xcel's methodology could also be made by seeking greater consistency across other Minnesota dockets. They highlighted three

[84] Staff notes that no other utilities filed comments in response to the Commission's notice seeking comments on Xcel's petition to modify the 2014 VOS Methodology.

[85] Staff asked the Department to clarify when this annual reporting should be filed and whether it should be part of the Company's annual VOS update filing (September 1).

dockets: Xcel's IDP (in 18-251), CIP dockets (in 16-541, 16-115, and 18-783), and Xcel's IRP (in 19-368), each of which considers avoided distribution costs. They noted that such a review might highlight the ways in which avoided distribution costs are considered internally at the utility and how they compare with external programs such as CIP.

However, staff cautions that there could be specific and important reasons why avoided distribution costs are treated differently across dockets. For example, IDP and IRP are planning dockets; consequently their outcomes and results are not used directly in setting rates. Moreover, Xcel's IRP (19-368) was filed only recently, and will be supplemented by further changes; therefore applying an avoided cost method from that ongoing docket to the VOS may be premature. Lastly, prior to directing such a workgroup, the Commission should confirm that this directive would not duplicate ongoing or planned work in other workgroups or dockets.

Staff notes that because the Commission is a quasi-judicial agency, it makes decisions based upon the record before it. Thus, it is neither surprising nor unusual for the Commission to arrive at different costs or planning values in different dockets. In most instances, both parties and Commissioners favor tailoring a decision to account for the circumstances present in that docket. Hence, as noted, planning dockets such as the IDP and IRP will produce differing outcomes than the current docket, which is focused on ratemaking, specifically setting a bill credit rate to be paid to CSG subscribers. At its October 17, 2019 agenda meeting, for example, the Commission set a solar demand credit rate but declined to set an avoided cost rate. Instead, it set an embedded cost rate, based upon the requests of parties and the facts specific to that docket.

Given these concerns, if the Commission considers the topic one that deserves further discussion, it could consider directing Xcel to convene a workgroup with interested stakeholders to compare and discuss the approach to avoided distribution costs in Xcel's IDP, CIP, and IRP dockets, including: (1) Xcel's Integrated Distribution Plan (IDP), in 18-251, (2) Xcel's CIP dockets (in 16-541, 16-115, and 18-783), and (3) Xcel's Integrated Resource Planning (IRP), in 19-368.[86] Staff notes, however, that the Commission has also authorized further proceedings on its Attachment 6 rate principles for DG tariffed rates, and the discussion here should not overlap with that ongoing proceeding.

Calculation of location-specific costs

In it March 22, 2019 Order,[87] the Commission directed the Department to continue its stakeholder process exploring the calculation of location-specific avoided distribution costs, and to file a proposal or progress report by December 31, 2019. Since this request to the Department is for either a proposal or progress report, staff does not believe it is necessary to extend the deadline at this time. However, the Commission may wish to hear from the Department on its progress towards meeting this request. Staff notes that the Department

[86] Chan et al, pp. 13-14.

[87] *Order Approving Xcel's Update to the 2019 System-Wide Value-of-Solar Tariff Rate with Modifications*, in 13-867, March 22, 2019, Order Point 3, p. 14.

may be waiting to see what the Commission decides regarding Xcel's proposal for a system-wide approach to determining the avoided distribution cost component.[88]

V. Decision options

I. Xcel's proposed methodology

1. Approve Xcel's proposed methodology for calculating the avoided distribution cost component in the VOS. Direct that the proposed methodology be used beginning with the 2020 VOS and in future VOS vintage years. *(Xcel, Department)*

2. Approve Xcel's proposed methodology for calculating the avoided distribution cost component in the VOS calculation with the revisions noted below. Direct that the proposed methodology, with revisions, be used beginning with the 2020 VOS rate and in future VOS vintage years. Xcel's proposed methodology will include some or all of the following revisions:

   A. ***50% deferral reduction factor***

   1. Take no action. (i.e. adopt the Company's proposal with the 50% deferral factor) *(Xcel, Department)*

   2. Remove the 50% deferral reduction factor. *(Fresh Energy, Chan et al, MnSEIA, IPS Solar)*

   3. Find that the current record lacks sufficient evidence to support the adoption of a deferral reduction factor for use in the calculation of the avoided distribution cost component. Remove the deferral reduction factor from the methodology for calculation of the 2020 VOS. Direct Xcel, if it decides to propose a deferral reduction factor for the 2021 VOS, to provide additional supporting evidence in its September 1, 2020 VOS annual compliance filing. Such evidence should include an evaluation of solar project locations, both CSG and other distributed solar projects as possible, compared to the locations of deferrable distribution investments made over the past 5 years and planned within the next 3-5 years. *(Fresh Energy, Chan et al, MnSEIA, IPS Solar)*

   4. Take no action to remove the 50% deferral reduction factor at this time. Require the Company to report annually on its planned and actual distribution spending, along with the placement of CSGs to assist with evaluating the continued reasonableness of Xcel's avoided distribution cost calculation methodology. *(Department, Xcel accepts)*

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[88] Staff also notes that, as part of an April 9, 2019 email to stakeholders describing the alternative proposal for the distribution cost component, Xcel indicated that the location-specific avoided distribution capacity costs would be discussed at a later date.

B. *Time period for calculating avoided distribution cost component*

1. Take no action. (i.e. adopt the Company's proposal for a 2-year historical and 3- year forecasted time period) *(Xcel, Department)*

2. Use 10 years of cost and distribution capacity data, including adding historical data for 2011 to 2015, and the per unit rate for avoided distribution capacity to be derived from the cumulative distribution investments (in $) added over a 10-year period and the cumulative distribution capacity (in MW) added over the same period. *(MnSEIA, IPS Solar)*

3. Direct further examination of MnSEIA's proposal for the use of 8 years of historical and 2 years of forecasted data. Direct Xcel to further investigate this issue in collaboration with the Department and stakeholders.

4. Direct Xcel to perform a sensitivity analysis of different time periods and their effect on the volatility of the value of the avoided distribution cost component from year to year. (*Chan et al*)

C. *Cost categorization*

1. Take no action to modify Xcel's proposed cost categorization. *(Xcel, Department)*

2. Adopt Xcel's cost categorization but direct Xcel, within 30 days of the issue date of the Order in this matter, to file a categorization framework, or decision tree, showing how specific types of distribution projects will be categorized for the purposes of future calculations of the VOS avoided distribution capacity component. *(Fresh Energy)*

3. Modify Xcel's cost categorization. Direct Xcel to add distribution O&M and general plant costs to the $/kWh distribution capacity component from FERC Form 1 data. The recommended general plant loader shall be 3.3%, inflating the economic value of avoided distribution capacity by 3.3% for general plant. The distribution O&M adder would be $17 per kW-year, or $0.0117 per kWh = $17 per kW/1,452 kWh/kW-year where 1,452 kWh/kW is the assumed annual PV production. *(MnSEIA, IPS Solar)*

4. Adopt Xcel's cost categorization but direct Xcel to work with the Department and other stakeholders to identify and provide further information on the Company's cost categorization process. Direct Xcel to provide additional information and transparency on its system of cost

categorization by meeting to discuss this issue with the Department and stakeholders. Direct specific examination of the proposal by MnSEIA to include O&M and general plant in the list of costs included in the calculation of the avoided distribution cost component.

D. Application of linear regression analysis

1. Take no action. (i.e. adopt the Company's proposal without application of a linear regression analysis) *(Xcel, Department)*

2. Modify Xcel's proposal by directing Xcel to use a linear regression to determine the $/kW slope when cumulative costs are compared to cumulative capacity additions. *(MnSEIA, IPS Solar)*

3. Adopt Xcel's proposal without linear regression analysis as proposed by MnSEIA but direct Xcel to further examine the proposal. Direct Xcel to further investigate this issue in collaboration with the Department and stakeholders.

E. Additional actions related to Xcel's proposed methodology

1. Take no action to require the re-calculation of the 2019 avoided distribution cost component or the 2019 VOS bill credit rate. *(Xcel, Department)*

2. Direct Xcel to re-calculate the 2019 avoided distribution cost component using the changes adopted by the Commission in Decision Options 2.A-D (above), and to re-calculate 2019 VOS based on these changes. *(MnSEIA, IPS Solar)*

II. MnSEIA's proposal to adopt a simple average for the 2020 VOS

1. Take no action. (i.e. do not adopt MnSEIA's proposal for a simple average for the 2020 VOS) *(Xcel, Department)*

2. Direct Xcel to implement MnSEIA's proposal for an interim value of $0.0252/kWh for the avoided distribution cost component for the 2020 VOS, and to use MnSEIA's simple average approach (based on values calculated under the current methodology) until a revised methodology is adopted by the Commission. *(MnSEIA, IPS Solar)*

III. Modifications to the 2014 VOS Methodology in Docket No. E-002/M-14-65

1. Take no action at this time to make permanent modifications to the 2014 VOS Methodology through the adoption of red-line changes.

2. Require Xcel to submit a compliance filing, within 20 days of the Order in this matter, with red-lined changes to the 2014 VOS Methodology reflecting the decisions made by the Commission at its October 31, 2019 meeting.

3. Modify the 2014 VOS Methodology by adopting the red-lined changes offered by Xcel in the Company's petition filed August 5, 2019 (Attachment C, pp. 40-43 and the 2014 VOS Methodology, pp. 34-36). *(Xcel)*

4. Modify the 2014 VOS Methodology by adopting the red-lined changes offered by Fresh Energy in comments filed August 23, 2019 (p. 3).

VI. Coordination of avoided distribution costs across dockets

1. Direct Xcel to convene a workgroup with interested stakeholders to compare the approach to avoided distribution costs in Xcel's IDP, CIP, IRP, and CSG VOS dockets, including: (1) Xcel's Integrated Distribution Plan (IDP), in 18-251, (2) Xcel's CIP dockets (in 16-541, 16-115, and 18-783), (3) Xcel's Integrated Resource Planning (IRP), in 19-368, and (4) Xcel's CSG docket, in 13-867. *(Chan et al suggestion; staff composed decision option)*

V. Further stakeholder discussions: Longer-term issues

1. Direct Xcel to work with the Department and other stakeholders, including Chan et al, to consider design options for the avoided distribution cost component of the VOS. These would include but may not be limited to the issues raised by Chan et al in this docket, such as lessons from other states, long-term peak load growth assumptions, sensitivity analysis of different time periods for system-wide calculation, as well as methods to de-average avoided distribution costs to account for specific location differences.

Attachment A

Evaluation of the Current Method for Avoided Distribution Costs (Chan et al, pp. 10-11, Table 2)

Does the method…	2014 Approved VOS Method
… take an approach appreciably more accurate than other approaches?	As the first-of-its-kind methodology applied in Minnesota, the accuracy of the method relative to other methods available at the time is difficult to discern.
… incorporate specific project data to develop estimates without being detrimentally dependent on individual projects; incorporate forecast information together with historic data?	Specific project data is not explicitly incorporated and the methodology is entirely backward looking without any notion of forecasting.
…utilize publicly available data (e.g. from FERC Form 1)	The methodology does rely mostly on publicly available data, although the designation of some investments as capacity-related is opaque.
… allow for easy calculation and updating; maintain consistency with ratemaking and integrated resource planning	The methodology has been relatively easy to calculate and update but relies on assumptions that are wholly inconsistent with ratemaking and integrated resource planning. In particular, the assumption in the methodology that the 10-year difference in peak load is a fair approximation for the driver of distribution-system investments is inconsistent with how the IRP justifies new investments (based on load forecasts).
… incorporate notions of marginality (rather than average) avoided costs	Theoretically, by focusing just on peak load growth, there is an attempt to only account for distribution investments to serve additional load; however, changes in peak load are not a fair approximation.
… address the lumpiness of investments	The 10-year window attempts to smooth over the lumpiness of distribution-system investments.
… incorporate variability associated with time/location differences	No, the current methodology provides no such differentiation.

Attachment B

Evaluation of Xcel's Alternative Method for Avoided Distribution Costs (Chan et al, pp. 12-13, Table 3)

Does the method…	Xcel's Alternative Method
… take an approach appreciably more accurate than other approaches?	The volatility of the method appears to be reduced compared to the current method, reflecting the long lifetime of distribution-system equipment, but accuracy with respect to true avoided costs is uncertain. Solar's value in reducing the volatility of net system peak demand is not incorporated.
… incorporate specific project data to develop estimates without being detrimentally dependent on individual projects; incorporate forecast information together with historic data?	Specific project data is not explicitly incorporated, but the method incorporates two historic and three forecasted years of data on capacity spending and capacity additions in aggregate and in planning areas. However, Attachment B of Xcel's May 1, 2019 filing does not appear to use the two years of historic data in calculating individual planning area estimates, basing those instead only on three years of anticipated costs and capacity needs.
… utilize publicly available data (e.g. from FERC Form 1)	No, data inputs are largely proprietary. For example, several commenters have noted the opaqueness of the designation of which distribution-system investments are "capacity related."
… allow for easy calculation and updating; maintain consistency with ratemaking and integrated resource planning	Appears to be easy to update but not consistent with other proceedings.
… incorporate notions of marginality (rather than average) avoided costs	No notions of marginality incorporated except in the ad-hoc 50% reduction factor. Justification for the 50% reduction factor has been questioned by several other commenters.
… address the lumpiness of investments	The five-year data-input to capacity spending and additions partially smooths out the volatility of lumpy investments, although longer time horizons may more accurately reflect the lifetime of solar projects and distribution-system infrastructure.
… incorporate variability associated with time/location differences	Differences in location are established at the planning-area level. Time differences are only incorporated through the peak load reduction factor in the VOS method.