

August 23rd, 2019

Daniel P. Wolf
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
Saint Paul, MN 55101

RE: Reply Comments on Xcel Energy's May 1, 2019 Filing on the Calculation of the Avoided Distribution Cost Component of the Value of Solar (Docket No. M-13-867)

Dear Mr. Wolf,

Assistant Professor **Gabriel Chan** (Center for Science, Technology, and Environmental Policy and the Humphrey School of Public Affairs, University of Minnesota), hereby provides comments regarding PUC Docket No. M-13-867, which involve considerations for the avoided distribution cost component of the Value of Solar (VOS). These comments are in reference to the notice of extended reply comment period published on August 9, 2019. **Matthew Grimley** and **Bixuan Sun** (Research Fellows at the Center for Science, Technology, and Environmental Policy, University of Minnesota) join as co-signers of these comments.

These comments are submitted with the intention of broadening the set of considerations and eventual decision options that can be considered by the Commission. In preparing this submission, we have reviewed relevant academic peer-reviewed literature, proceedings in other Minnesota dockets, and reviewed public documents and consulted with expert stakeholders in other U.S. states. Through this review, we have come to deeply appreciate the complexity of the estimation of avoided distribution costs. Such calculations require many specific and untestable assumptions. Therefore, the context in which an avoided distribution cost calculation is applied matters significantly for the choice of methodological approach that best serves the public interest.

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. This situation is a plausible explanation for the outcomes of the status quo methodology. The general dissatisfaction among all parties with the current methodology suggests that a way forward for calculating avoided distribution costs that serves the public interest need do more than simply yield outcomes that are on-average **accurate**. The methodology must also guarantee that outcomes are **fair** and **reasonable**, as reflected in the Commission's May 20, 2019 request for comments asking if Xcel Energy's proposed methodology "yield[s] accurate results that are fair and reasonable for all VOS stakeholders?"

To meet the multiple objectives of **accuracy**, **fairness**, and **reasonableness**, we propose a set of criteria for evaluating possible methodologies for avoided distribution costs that is derived from a parallel discussion in other dockets (see Section 2.3). Based on applying these criteria to the current and proposed methods and surveying alternative approaches, we reached the following three conclusions about the calculation of avoided distribution costs in Section 3:

- 1) *Section 3.1*: The avoided distribution cost component is more likely to yield **reasonable** and **accurate** results if based on historic and planned distribution system costs (as in Xcel Energy’s proposed method) instead of aggregate proxy measures derived from peak load growth (as is done in the current method);
- 2) *Section 3.2*: The utilization of historic and planned distribution system costs in calculating the distribution cost component could be made more **fair** and **accurate** (than Xcel Energy’s proposed method) by drawing lessons from other Minnesota proceedings and the methodologies used in other states; and
- 3) *Section 3.3*: Introducing locational differentiation in the avoided distribution cost component could be done in a **fair** and **reasonable** manner by adopting methods for “de-averaging” system-wide estimates instead of independently calculating estimates at different locations (as in Xcel Energy’s proposed method).

1. Context and Complexity of the VOS: An Overview

The current issue before the Minnesota PUC goes to the heart of one of the most pressing challenges for the transition of the electricity system: how to fairly integrate distributed energy resources (DERs) in the context of an electricity system whose rules, processes, and organizations developed to support centralized generation and infrastructure.

The analytic task of establishing the VOS is fundamentally at tension with itself and requires compromises that balance the competing goals of accuracy and benefit/practicality. In reviewing possible VOS approaches, the National Renewable Energy Laboratory illustrated potential tradeoffs with a schematic (replicated in Figure 1)¹. This report illustrated this tension in a similar context to the one currently under consideration by the Minnesota PUC:

Location-specific VOS rates could be designed to represent a greater or lesser VOS across an individual utility’s service territory, which would manifest in utility cost savings at the distribution or transmission level. While it is more accurate to reflect each individual solar system’s value to the utility system, the question remains whether this level of accuracy yields sufficient benefit or practicality. When put into practice, the VOS rate could vary across hundreds of individual distribution circuits or in several larger geographic areas. But this accuracy needs to be balanced against the simplicity of a single VOS rate across an entire utility’s territory. Limiting the number of different VOS rates will likely facilitate calculations, rate updates, customer marketing and communications with customers, the industry and other stakeholders. Just as utilities set electricity rates based on an average customer consumption profile per customer class, a single VOS rate,

¹ See <https://www.nrel.gov/docs/fy15osti/62361.pdf>

representing the average value that solar provides across the system may be easier to set and implement than multiple rates.

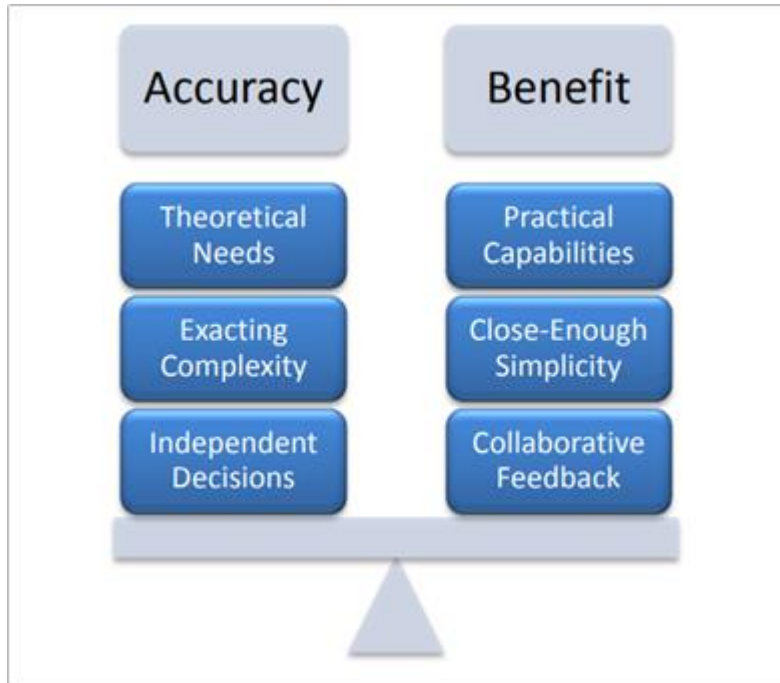


Figure 1. Schematic Representation of the Value of Solar Balancing Act (NREL, 2015)

While the VOS aspires to fairly compensate solar generators only for the social value they create, that the VOS was considered too low before for some developers, and that it is now (in the 2020 vintage) considered too high to the utility, is evidence of the VOS's role as a negotiated financial instrument that acts as an incentive for third parties to provide the best approximation of socially optimal outcomes. Note that *an incentive is not a subsidy*, and in this context, the incentive that the VOS tariff provides is designed explicitly to not subsidize any party by rewarding third-party solar developers only for the social value they create². The balancing act that the VOS methodology must play between accuracy and benefit/practicality is compounded by the irreducible uncertainty in many of the fundamental drivers of the system-value that solar provides (e.g. long-run avoided costs of volatile natural gas purchases).

Further, the VOS must also take definitive positions on complex philosophical questions of fair attribution of costs. Avoided costs are estimated ex-ante: they avoid future costs (in the short- and long-run). But in reality, costs that were ex-ante anticipated to be avoidable may not be avoided at all, as the electric grid's composition changes from what had been a planned counterfactual. The possibility of a

² Here we use the term "incentive" as is commonly used in public policy and economics. For example, the U.S. Environmental Protection Agency states, "incentive-based policies influence rather than dictate the actions of the targeted parties. Incentive-based policies leave the ultimate choice of action to the affected parties, based on their own evaluation of the costs and benefits of the action. By correcting the incentives faced by private parties to reflect important social costs as well as private costs, incentives policies encourage private decisions that more closely approximate socially optimal outcomes." Retrieved from: <https://www.epa.gov/environmental-economics/economic-incentives-options-environmental-protection-1991>

substantial difference between the ex-ante anticipated avoided costs and the ex-post realized avoided costs could be particularly challenging for avoided distribution system costs. As the electricity system continues to deploy an increasing amount of distributed energy resources (DERs), the demand and the capacity to integrate DERs is rapidly changing.

2. Avoided Distribution Costs: An Overview of Methods and Specific State Proceedings

Against this theoretical and philosophical background, existing methods to calculate avoided distribution costs have been developed in the academic literature, other Minnesota proceedings, and in other states. These methods rely on either sophisticated system-wide simulation tools or complicated forecasts.

Across all extant studies for calculating avoided distribution costs, we observed an implicit or explicit reckoning with the difficulty of this analytic task. Coordinating growing distribution capacity with growing generation capacity (of either centralized or distributed facilities) is an unsolved problem of markets and utility modeling in general^{3,4}.

Perhaps for these tensions between accuracy, fairness, and reasonableness, there is a wide range of methods to estimate avoided distribution costs. They include system planning approaches, using combinations of historical and forecast information, marginal cost of service studies, and simple distribution cost sampling (see Section 2.3 for a list of proposed methods for avoided transmission and distribution costs in the context of energy efficiency programs).⁵ A 2014 survey of these methods (in the context of energy efficiency) found that 24 utilities had avoided distribution costs between \$0 and \$171 per kW-year, with an average avoided distribution cost of \$48.37 kW-year. While indicative of the variety of methods and the variety of estimated avoided costs, this survey says nothing of the validity of those methods.

2.1. Distribution System Simulation Models

In an academic example, Cohen et al (2016) use a simulation tool developed by the Pacific Northwest National Laboratories called GridLAB-D⁶ to study distribution feeder replacement⁷. They used the simulation tool to identify which distribution capacity projects would occur in the next 10 years in the baseline scenario and then compute the number of years the same project would be deferred in different PV penetration scenarios. The avoided distribution cost is then taken as the capital depreciation value during the deferred period. The use of a sophisticated simulation tool allows this study to provide a realistic "counterfactual" for the calculation of those distribution-system costs that could be avoided with non-wires alternatives. This approach also takes into account the broad system impacts of solar

³ Cramton, P. (2017). Electricity market design. *Oxford Review of Economic Policy*, 33(4), 589-612

⁴ Trabish, H. (Nov. 13, 2018.) Location value of DER is essential to grid planning. So why hasn't anyone found it? *Utility Dive*. Retrieved from <https://www.utilitydive.com/news/location-value-of-der-is-essential-to-grid-planning-so-why-hasnt-anyone/541946/>

⁵ The Mendota Group, LLC. (Oct. 23, 2014). Benchmarking Transmission and Distribution Costs Avoided by Energy Efficiency Investments for the Public Service Company of Colorado. Retrieved from <https://mendotagroup.com/wp-content/uploads/2018/01/PSCo-Benchmarking-Avoided-TD-Costs.pdf>.

⁶ See <https://www.gridlabd.org/>

⁷ Cohen, M. A., Kauzmann, P. A., & Callaway, D. S. (2016). Effects of distributed PV generation on California's distribution system, part 2: Economic analysis. *Solar Energy*, 128, 139-152.

deployment on the distribution system and can be updated easily with different inputs and assumptions. However, applying this approach as part of the VOS tariff would reduce transparency, as the model includes many complex assumptions.

2.2. Lessons from New York

New York is a leading state in developing valuation approaches for DERs for the purposes of tariff design⁸. Though their overall methods appear to fall short of assured accuracy, they incorporate reasonable and fair standards of avoided distribution costs. The following is our attempt at a summary of recent developments in New York, but we note that their approach may still evolve.

In New York, where Reforming the Energy Vision (REV) is attempting to reconstruct locational values for DERs, most utilities use a deterministic forecast based on historical trends to help inform avoided distribution costs. Central Hudson Gas & Electric, however, uses probabilistic methods to forecast future load growth trajectories given different load reduction measures, including DERs. The timing on infrastructure upgrades is simulated to occur after the forecasted load exceeds the designed ratings for two consecutive years. The avoided costs are the difference between the costs with and without the load reduction necessary to avoid or defer the upgrade. This method does not use complicated simulation tools, hence increasing transparency of the calculations, at the cost of reduced accuracy in obtaining proper “counterfactual” load growth profiles in baseline and load-reduction scenarios. In addition, the load forecast model is applied separately and independently for each substation. The results can be sensitive to outliers and compounding errors.

New York proposed the Value Stack Compensation approach in 2016 to “de-average” Marginal Cost of Service (MCOS), which is submitted by utilities and takes into account overall system avoided distribution costs, such as savings from deferred feeder upgrades. The Value Stack approach de-averages utility level MCOS into two components based on peak demand reduction from distributed generators: “Demand Reduction Value (DRV)” that applies across the service territory and an additional “Locational System Relief Value (LSRV)” that applies to high-value areas for a limited number of MWs. Specifically, DRV assigns avoided distribution costs based on the amount of electricity generated by a DER project during the top 10 peak demand hours in a year. LSRV is applied on top of DRV to DERs in “high-value areas” where the impending system needs are high according to utilities. It is based on a DER project’s capacity to inject energy during the top 10 peak demand hours in a year. DER projects receive lump sum monthly credit in the following year and these rates are updated annually.

The Value Stack compensation scheme was implemented in November 2017, and received critical feedback from stakeholders. The main criticism was that the DRV and LSRV mechanisms are too complicated and highly unpredictable and volatile because they depend only on the top 10 peak demand hours in a year, which are difficult to predict in advance and are sensitive to weather shocks. In addition, the method for determining “high-value areas” for LSRV calculation is not sufficiently transparent.

⁸ Hall, J., Kallay, J., Napoleon, A., Takahasi, K., Whited, M. (2018). Locational and Temporal Values of Energy Efficiency and other DERs to Transmission and Distribution Systems. ACEEE Summary Study on Energy Efficiency in Buildings. Retrieved from <https://www.synapse-energy.com/sites/default/files/ACEEE-Paper-Values-EE-DER.pdf>. See also NY PSC docket 15-E-0751

Overall, although the DRV and LSRV mechanisms achieved a high level of granularity in reflecting avoided distribution costs, they make it difficult for developers to make investment decisions and for utilities to make long-term planning decisions and hence do not provide proper price signals and incentives for the expansion of DERs.

Taking into account these criticisms, the New York Department of Public Service revised the method in April 2019. The updated approach replaced the base value MCOS with existing system-wide marginal cost estimates for energy efficiency (EE) resources, citing similar contributions to the distribution system between DERs and EE resources. Specifically, they take the \$/kW-year marginal cost for EE resources and assign it as \$/kWh to the power generated during the 240 peak summer hours in the afternoons (1 pm to 6 pm) of non-holiday weekdays from June 24 through August 31 each year. The resulting amount is then divided by 12 and provided as a monthly lump-sum credit to monthly bills of DER system owners. This revision reduces the complexity and increases the transparency of the compensation scheme. Spreading the base value across many more peak summer hours instead of just 10 hours seems to address the uncertainty and volatility issues. In addition, DRV values will be updated every two years instead of annually, and the changes are bounded within 5% in either direction. Finally, LSRV will be phased out due to the lack of transparency in its calculation.

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.

We note that in addition to New York, California is also engaging in a multi-year stakeholder process to study approaches for calculating avoided distribution system costs (among other issues) through the California Integrated Distributed Energy Resources (IDER) and Distribution Resource Planning (DRP) Working Groups⁹.

2.3. Lessons from Energy Efficiency Programs

In the Minnesota CIP docket 16-541, on July 1, 2016, DOC cited a 2014 report by the Mendota Group prepared for Xcel Energy's Colorado subsidiary¹⁰ that outlined a number of alternative approaches to calculating avoided transmission and distribution (T&D) costs¹¹. Appendix A of the Mendota Group report and Table 1 below outlines eight alternative methods for calculating avoided T&D costs with associated examples in practice and strengths and weaknesses. We have replicated this table below:

⁹ See <https://drpwg.org/sample-page/drpf/>

¹⁰ <https://mendotagroup.com/wp-content/uploads/2018/01/PSCo-Benchmarking-Avoided-TD-Costs.pdf>

¹¹

<https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7B1B9FAB57-3FD6-483C-92FA-C4C2686710D5%7D&documentTitle=20167-122923-01>

Table 1. Approaches to Calculating Avoided T&D Costs, adopted from Mendota Group

Table 1: Approaches to Calculating Avoided T&D Costs⁷

Method	Brief Description	Examples	Strengths	Weaknesses
System Planning Approach	<ul style="list-style-type: none"> Uses costs and load growth for specific T&D projects based on a system planning study 	<ul style="list-style-type: none"> Vermont Electric Company (2003) - focused on specific transmission upgrade 	<ul style="list-style-type: none"> Potentially more accurate Uses specific project data to develop estimates Forces consideration of DER effects on project-by-project basis 	<ul style="list-style-type: none"> Costly and time consuming May not be appreciably more accurate than other approaches Dependent upon individual projects included in analysis
Mix of Historical and Forecast Information	<ul style="list-style-type: none"> Uses data on historical and forecast T&D investments, determines what's related to load growth, and weighs the historical and forecast contributions 	<ul style="list-style-type: none"> ICF Tool used in the Northeast, Vermont DPS variation 	<ul style="list-style-type: none"> Uses publicly available FERC Form 1 data Easily calculated and updated Uses a form of marginal costs Addresses "lumpiness" of T&D investments Used by multiple other states Relies upon historical as well as forecast information 	<ul style="list-style-type: none"> Assumes it's possible to differentiate amount of T&D investment that corresponds to load growth rather than maintenance, reliability and customer growth Does not incorporate variability associated with time/location differences Can't readily handle low forecast growth
Current Values	<ul style="list-style-type: none"> Develops average cost to serve existing load by dividing each system's net cost 	<ul style="list-style-type: none"> MidAmerican Energy (IA, IL, SD), Commonwealth Edison (IL) 	<ul style="list-style-type: none"> Uses publicly available FERC Form 1 data Easily calculated and updated 	<ul style="list-style-type: none"> May tend to undervalue Does not incorporate variability associated with time/location differences
Rate case marginal cost data with allocators	<ul style="list-style-type: none"> Uses T&D marginal cost of service data from utility rate cases and apply time and locational factors related to weather or specific substation loadings 	<ul style="list-style-type: none"> California IOUs 	<ul style="list-style-type: none"> Uses publicly available data (rate case portion) Uses approach consistent with ratemaking Uses time and location differentiated data Uses marginal cost information 	<ul style="list-style-type: none"> Potentially costly and time consuming May not be appreciably more accurate than other approaches Somewhat assumes use of hourly avoided costs for Generation Requires estimation of investments deferred by EE
Rate case marginal cost data	<ul style="list-style-type: none"> Use T&D marginal cost of service data from most recent rate case 	<ul style="list-style-type: none"> Ameren (MO), PacifiCorp (OR, UT, WA), Nevada Energy, Consolidated Edison (NY) 	<ul style="list-style-type: none"> Uses publicly available data Is approach consistent with ratemaking Uses marginal cost information 	<ul style="list-style-type: none"> May not be appreciably more accurate than other approaches Requires estimation of investments deferred by EE
IRP Method	<ul style="list-style-type: none"> Uses with and without EE runs to determine avoided transmission costs 	<ul style="list-style-type: none"> Tucson Electric Power 	<ul style="list-style-type: none"> Is consistent with integrated resource plan 	<ul style="list-style-type: none"> Is highly dependent on IRP's model ability to calculate transmission costs Requires integrated resource plan Only updated as frequently as resource plan Typically can only provide transmission

Averaging method	<ul style="list-style-type: none"> Take simple average of a selection of similar jurisdictions 	<ul style="list-style-type: none"> Wisconsin Focus on Energy Market Potential Study (used Iowa) Northwest Conservation and Electric Power Plan (used 8 utilities) 	<ul style="list-style-type: none"> Uses publicly available data Very easily calculated 	<ul style="list-style-type: none"> Must pick appropriate proxy utilities for Averaging Not specific to one utility
Simple Method	<ul style="list-style-type: none"> Take representative sample of recent T&D upgrade projects, divide by increased capacity and annualize 	<ul style="list-style-type: none"> Unknown 	<ul style="list-style-type: none"> Very simple Provides real information from specific example Can be done for transmission, distribution and sub-transmission 	<ul style="list-style-type: none"> Project may not be system representative Must still determine what portion of increased capacity relates to load growth

This table provides a helpful framework for developing criteria for evaluating proposed avoided distribution cost estimates. We suggest the following criteria for a proposed methodology building on the evaluations from the “strengths” and “weaknesses” columns of the table:

- Take an approach appreciably more accurate than other approaches
- Incorporate specific project data to develop estimates without being detrimentally dependent on individual projects; incorporates 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
- Incorporate notions of marginality (rather than average) avoided costs
- Address the lumpiness of investments
- Incorporate variability associated with time/location differences

3.1. The Current Method: Unreasonable Because of Discrete Inputs of Peak Load

The current 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 the reliance on just two data points of peak load. We also note that the 2017 and 2018 VOS calculations relied on different datasets of historic peak load than the 2019 and 2020 calculations, as demonstrated in Figure 2. Figure 2 displays how the current method incorporates peak load as the difference between only two data points 10 years apart. The method ignores the changes in peak load in the interim period between the two end points, and we note that for each of the calculations from 2017-2020, the maximum peak load over the full 10-year period was greater between the endpoints than at the endpoints used in the calculations. 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.

The most recent calculation of the avoided distribution cost under the current method demonstrates how relying on just two data points of peak load can yield volatile results. The fundamental statistical rationale is that the maximum of a distribution (in this case, the maximum of total annual load) has a high variance. Peaks are highly variable from year to year, as demonstrated in Figure 2, and therefore the difference between two peaks is not a statistically reasonable approximation for peak growth rates.

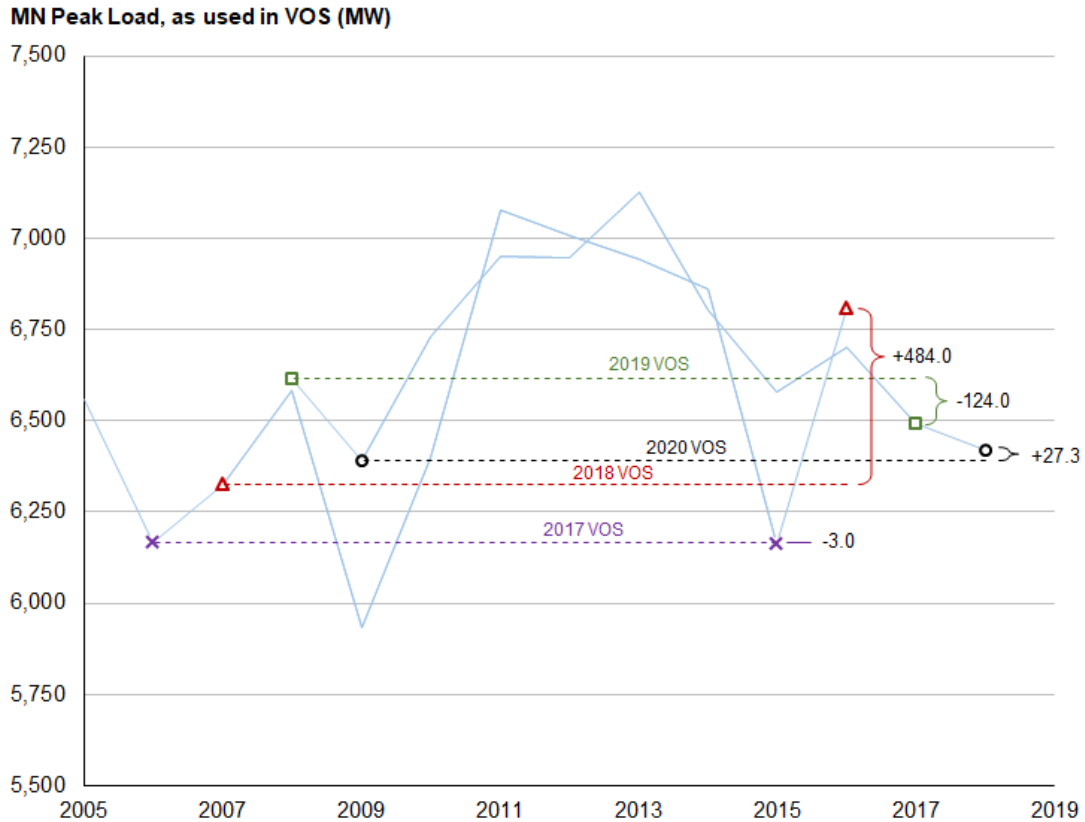


Figure 2. Weather-adjusted peak load, as represented in the Value of Solar calculations for 2017-2020 under the current methodology in Docket 13-867. Peak load varies substantially from year to year, but the current methodology only takes the difference in peak load over a 10-year span as the input to the methodology. Because of the large variability in peak load, this simple difference does not actually represent changes in distribution system needs. The difference in peaks is also highly volatile, and because this difference enters the formula in the denominator, the VOS component is highly volatile. (Note: It is unclear why historic peak load data included in the VOS calculations differs for 2008 - 2016 for the 2019/2020 VOS calculation and the 2017/2018 VOS calculation.)

A more reasonable approach to incorporating notions of peak load growth would be to utilize assumed fixed growth rates, as is done in the Integrated Resource Plan (IRP). Figure 3 below replicates a figure from the 2019 Xcel Energy IRP that shows an average ~0.2% annual peak load growth rate. This growth rate is net of energy efficiency, but it is conceptually unclear if energy efficiency should be included or excluded in the determination of peak load for the purposes of the VOS¹².

¹² It is unclear because future energy efficiency investment is incentivized under the CIP based on its role in reducing marginal system costs but the VOS makes the same assumption about marginality. Only one resource can technically be the marginal resource, but it is unclear whether that should be an energy efficiency resource or a solar resource.

Figure 3-2: Forecasted Peak Load, After Energy Efficiency Adjustments (MW)¹

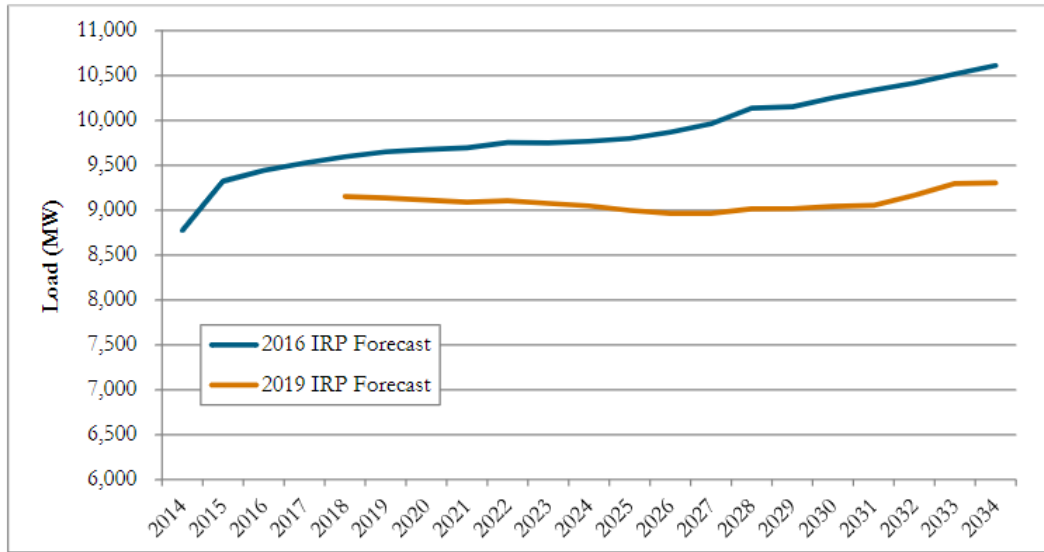


Figure 2. Forecasted peak load, replicated from Xcel Energy’s 2020-2034 Upper Midwest Integrated Resource Plan (IRP). The figure shows that in the most recent IRP (shown in orange), Xcel forecasts average annual growth of peak load of less than 0.2% (after accounting for energy efficiency). This is a significant reduction in peak load compared to the previous IRP forecast (shown in blue).

In addition to the concerns about peak load, there are other concerns about the current methodology that we raise in Table 2. Table 2 applies the evaluation criteria introduced in Section 2.3 to assess the current methodology.

Table 2. Evaluation of the Current Method for Avoided Distribution Costs

Does the method...	2014 Approved 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.

3.2. Xcel Energy’s Proposed Method: An Improvement that Could be Made More Fair and Accurate

Xcel’s proposed method for calculating avoided distribution costs represents a conceptual break from the current method. Rather than relying on peak load growth and total capacity-related investments made historically, the method looks at actual and planned distribution system investments and the associated capacity that those investments support. In this way, Xcel’s proposed methodology represents a conceptual approach similar to that used in the Conservation Improvement Program for avoided distribution costs.

While we believe Xcel’s proposal to be a significant conceptual improvement to the current method (primarily because it does not rely on peak load growth and instead relies on actual and planned costs), there is still room for improvement. This improvement can be identified by re-examining some of the untestable assumptions and opaque data sources relied on in the proposed method. As other commenters have identified, the use of a 50% reduction factor is an untestable assumption that warrants additional justification. Further, the identification of some distribution system investments as capacity-related could

be made more transparent. Finally, the choice of a limited number of historic and forecast years seems arbitrary and additional sensitivity could be conducted to limit the volatility of the resultant values from year to year. We provide an evaluation of Xcel Energy’s alternative methodology in Table 3.

Table 3. Evaluation of Xcel’s Alternative Method for Avoided Distribution Costs

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.
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Potential improvements to Xcel Energy’s methodology could also be made by seeking greater consistency with other Minnesota dockets. We highlight three dockets, Xcel Energy’s Integrated Distribution Plan (IDP) (docket 18-251), Conservation Improvement Program (CIP) (dockets 16-541, 16-115, and 18-783), and Integrated Resource Plan (IRP) (docket 19-368) where consideration of avoiding distribution costs is deliberated. This comparison is done to highlight the ways in which avoided distribution costs are considered internally at the utility and how they are considered with external programs such as CIP.

In its IDP, Xcel Energy considers avoided distribution costs mostly in potential non-wires alternative procurements^{13,14}. Its distribution budget is “an ongoing and iterative process” composed within 5-year cycles. Xcel Energy acknowledges 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. For now, the utility considers that NWAs are best suited for deferring specific capacity-related distribution investments as they occur. Each NWA must be rated against traditional capacity solutions through a “cost/benefit basis” to be judged as sufficiently cost-competitive. The PUC ordered Xcel to provide more granular information at the distribution for its next IDP update in 2019.¹⁵

Within its IDP, Xcel Energy also notes its efforts through CIP to allocate energy efficiency impacts to each distribution substation and feeder on a proportional basis of percentage of system load share. A summer peak analysis determines if specific projects can be deferred, and then using that deferral value, the cost/benefit of particular technologies are judged to be cost effective through CIP.¹⁶ The utility’s discrete method of calculating avoided T&D was selected by the Department of Commerce over its continuous method.

Xcel Energy’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 Energy’s prior avoided transmission and distribution costs of \$36.23/kW-

¹³
<https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={D0117164-0000-C716-B2CA-4BE90B5EF708}&documentTitle=20187-144590-01>

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<https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={E098D466-0000-C319-8EF6-08D47888D999}&documentTitle=201811-147534-01>

¹⁵
<https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={5072FC6B-0000-C715-8B8F-F971D67B302B}&documentTitle=20197-154416-01>

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<https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7BD0549A5D-0000-CE15-BEF1-9B48DB00A554%7D&documentTitle=20177-134393-01>

year for 2017.¹⁷ Each of the current and prior avoided costs were determined on a system-wide basis, as energy efficiency was judged to be broadly implemented enough to result in a single value even though specific avoided T&D costs were acknowledged but not calculated.¹⁸

In both the CIP dockets and its current IRP, Xcel Energy seems to determine that geo-targeted demand-side management is the best solution to avoiding distribution investments. In the IRP, in particular, the utility says that demand response can help defer both systemwide and specific distribution investments.¹⁹ In the IRP's appendix G2, a utility-commissioned Brattle report uses CIP-adapted avoided T&D cost numbers to judge demand response's ability to avoid T&D costs. The utility also states it is also working with the Center for Energy and Environment to pilot a geotargeting study aimed at increasing residential demand response to defer distribution upgrades.

The differences between the dockets shows organizational change (and some barriers) within the electricity sector and opportunities for learning across these proceedings. There are also discrepancies in the values of avoided distribution costs between these dockets. For instance, within the IRP and IDP, values of geo-targeted avoided costs for distribution upgrades appear to be determined internally at the utility and/or forthcoming in upcoming filings. With CIP, those numbers and calculations are more transparent. Despite the increased transparency of CIP, in all cases between these dockets, complete visibility into the state of the distribution system is limited.

Some commenters in the dockets have suggested linking these proceedings in a more formal way. Other commenters, including those from the state, have suggested more opportunities for learning across these initiatives. At the least, with an understanding that grid modernization is a slow-moving and developing process, we suggest increased transparency and collaboration between these different planning processes can create a more uniform vision of the differentiated value of DERs to the public.

3.3. A New Proposed Method: De-Averaging to Add Locational Differentiation that is Fair and Reasonable

The estimation of avoided distribution costs is inherently uncertain. Any methodology may yield estimates that are unreasonable. Xcel's proposed methodology has the potential to yield unreasonable results if there are idiosyncratic periods with higher (or lower) distribution system investments. As described above, one approach to reducing the probability of unreasonable results is to average over longer periods of historical and forecasted costs. However, the probability of yielding at least one unreasonable cost is multiplied when the same methodology is repeated independently in multiple jurisdictions. This is exactly what could happen in the proposed methodology's approach to calculating

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<https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={09A3CF6C-CC72-42A1-A867-E449BAC71BAF}&documentTitle=20162-118355-02>

¹⁸

<https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7B4E448E54-2E17-4890-9067-10534F918A48%7D&documentTitle=20169-124805-01>

¹⁹

<https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7B10FBAE6B-0000-C040-8C1D-CC55491FE76D%7D&documentTitle=20197-154051-03>

spatially disaggregated estimates. The potential for the current methodology to yield at least one unreasonable spatially disaggregated result is explained with statistical reasoning in Box 1.

Box 1. How the “Multiple Comparisons Problem” can create unreasonable results

The proposed methodology independently estimates the avoided distribution costs in nine planning areas. Each estimate is based on data unique to each planning area and a similar set of assumptions about the relationship between past investments and future avoided costs. This approach amounts to multiple independent avoided distribution cost estimates in each planning area. Theoretically, this increases the precision of each individual estimate (because deferred distribution costs should not have a material impact on distribution costs in other planning areas, it follows that the avoided distribution costs in one planning area should only be based on information from that one planning area—although there may be marginal spillover effects around planning area boundaries). However, independent estimates of avoided distribution costs raise the specter of yielding occasional severe outliers in individual planning areas.

To illustrate, suppose that the current methodology imperfectly estimates true avoided distribution costs due to random statistical noise due to the difficulty in estimating avoided distribution costs. Incorrectly high estimates can yield an unreasonably high public cost (e.g. by directing solar investment to areas where more generation isn’t needed—or not directing solar investment to the areas where it is most needed—and therefore requiring new distribution system upgrades at a cost borne by all ratepayers). Again, for illustration, suppose that unreasonable high public costs are produced by a methodology in 5% of cases. In other words, when the methodology is applied in a single planning area, an unreasonably erroneous estimate would only occur in 5% of cases. Yet if this methodology is applied independently in 10 planning areas, the probability that at least one estimate would be unreasonably high would be 40% ($1 - (1 - 0.05)^{10}$). This general phenomenon is known in statistics as the “Multiple Comparisons Problem.”

Stated simply, as the number of independent forecasts increases, the more likely it is that there will be forecasts that exhibit an undesired level of statistical noise. This statistical problem is relevant in this context because just a single unreasonable statistical mis-forecast can yield an avoided distribution cost estimate that would drive too much development in a single planning area at the detriment of other valuable development opportunities. This exact outcome is manifest in the estimates of the current method which show avoided distribution costs in the Minnetonka planning area of 27.72 cents per kWh. The Minnetonka value is 39-times greater than the median of the nine planning areas. This phenomenon is apparent to a lesser--but potentially still important--degree in the proposed alternative methodology. The alternative method gives an estimate for the Newport planning area that is 4.5-times greater than the median of the nine planning areas. Is a factor of 450% above the median for an entire planning area’s avoided distribution cost reasonable? Perhaps, but more information on whether this is a realistic degree of variability across Xcel’s planning areas is difficult to discern without further justification. Protecting the public interest should imply directly interrogating whether or not this degree of variability is in fact “reasonable.”

With this in mind, we propose a new method to create locationally specific differentiation in the avoided distribution cost estimate. Our proposal is based on the methodology developed in New York to first

calculate a system-wide average avoided distribution cost and then to apply a set of multipliers that “de-average” the system-wide avoided cost estimate to locationally specific values. Our proposed method has three steps:

Step 1: Estimate total system avoided distribution cost

The first step of this approach calculates the system-wide avoided distribution cost. This step can be accomplished through the cost-based approach that Xcel Energy has proposed, although the modifications raised in other comments and the questions we raise in Section 3.2 should also be considered.

Step 2: Establish location-specific multipliers (de-averaging weights)

The second step of this approach is to establish geographic units (such as planning areas) and create weights that correspond to the relative potential for solar installed in the geographic unit to avoid distribution system costs. These weights could take as inputs location-specific variables, such as:

- Peak load growth
- Anticipated load growth (e.g. from anticipated beneficial electrification, large public/private energy-consuming projects--such as the Light Rail expansion or housing developments)
- Anticipated generation growth, particularly other distributed energy resources with similar generation profiles as projects under the VOS (e.g. rooftop solar)
- Demand profiles (incorporated in the weights in a sophisticated manner or through specific peak load reduction (PLR) factors)

We do not propose a specific methodology for calculating location-specific multipliers; however, once developed, it would be possible to set some constraints around the multipliers so that they remain reasonable (for example, multipliers could be constrained to be between 0.5 and 2). Multipliers could also be smoothed over time through moving averages.

Multipliers would then be multiplied by the system-wide average to de-average the avoided distribution cost component to yield location-specific tariffs.

Step 3 (optional): True-up avoided distribution cost bill credits to equal total cost

By creating locationally differentiated weights, the intention would be to appropriately reward solar development that takes place in areas with greater VOS tariffs. If the locational incentive is great enough, development may shift significantly to areas with higher tariffs. Therefore, the realized average avoided distribution cost component may not equal the ex-ante estimated average that formed the basis of the tariff. This could be addressed by trueing up the distribution cost components of the tariff to equal the ex-ante total. This complexity may not be necessary if the total bill credit uncertainty is not significant.

The key advantage of this proposed methodology is that it avoids the possibility of individual unreasonable avoided cost estimates. A single system-wide average forms the basis of all location-specific tariffs and regulators would be able to set limits on the degree of spread between the multipliers so that no one location is subject to an unreasonably high or low tariff. This approach would also allow for more dynamic management of the program by allowing continuous refinement of the size of the geographic units over which tariffs are differentiated (i.e. future iterations could introduce differentiation within planning areas). This approach also separates the analytic exercise of estimating total avoided

distribution costs (and the associated issues described in Section 3.2) from the analytic task of incorporating locational differentiation. Table 4 provides an evaluation of our proposed methodology.

Table 4. Evaluation of Our Proposed Method for Avoided Distribution Costs

Does the method...	Our Proposed Method
... take an approach appreciably more accurate than other approaches?	Can be equivalently accurate to other methodologies for total system avoided distribution costs. Location-specific avoided costs may be more or less accurate due to the less direct approach to incorporating historic data but a possibility to incorporate a wider range of forward-looking information.
... incorporate specific project data to develop estimates without being detrimentally dependent on individual projects; incorporate forecast information together with historic data?	Can incorporate specific project data in the multipliers and can avoid dependence on individual projects by developing procedures to smooth over anomalies.
... utilize publicly available data (e.g. from FERC Form 1)	Flexible. Multipliers could be developed based on publicly available data while total system avoided distribution costs could rely on proprietary data.
... allow for easy calculation and updating; maintain consistency with ratemaking and integrated resource planning	Multipliers can be incrementally updated to increase (or decrease) sophistication to balance accuracy with close-enough simplicity. Not necessarily consistent with other proceedings but multipliers can be informed by other proceedings that develop location-differentiated distribution-system cost information.
... incorporate notions of marginality (rather than average) avoided costs	Possible to include notions of marginality in development of multipliers. Marginality can be reinforced through the application of the optional third step to true-up total avoided distribution costs to reward more distributed deployment.
... address the lumpiness of investments	Multipliers can address lumpiness by intentionally constraining variability
... incorporate variability associated with time/location differences	Locational variation can be established flexibly through the multipliers. Time variation can be incorporated through multipliers that take into account differentiation in peak load reduction (PLR).

4. Open Questions

The complexity of establishing a VOS begs the question, “Is this framework worth it?”

Our impression is that the PUC, Xcel Energy, and other stakeholders have spent a disproportionate amount of time and effort establishing the VOS relative to the scope of the electricity system and customers affected by solar investments under the VOS to date. We acknowledge other complementary frameworks to prudently bring new energy resources online, such as running competitive procurements and running programmatic solicitations for fixed quantities of resources.^{20,21}

Looking to the long-run transition of the energy system, however, the complexity of the VOS (and other such avoided cost calculations) may be necessary to create an environment for distributed resources to be deployed in a manner that recognizes the full system-value these resources can provide.

The VOS acts as a boundary object--a point of negotiation and a neutral incentive--for third-party investment on the grid.²² Negotiating the complexity of the VOS is a problem that is inherent to other boundary objects that are integral to other distributed energy resource proceedings, such as CIP, the IDP, and the IRP. Complexity is necessary, however, especially for distributed resources that are to be deployed in an electricity system where even the smallest resources, if deployed over and over, can have ripple effects throughout the system.

As noted before, we recognize that the VOS is not the only domain in which the complexity of valuing DERs arises. Several key dockets before the PUC grapple with the same fundamental issues. CIP has long-established procedures for recognizing the system impact of end-use energy efficiency measures (e.g. the cost tests for CIP include methodologies for estimating avoided distribution and transmission costs attributable to efficiency measures). The IDP and IRP processes both take a systems-level perspective on investment planning and seek to model how DERs affect the value of alternative investment strategies (e.g. the IRP establishes effective load carrying capacities for DERs so that their system-value can be compared to dispatchable centralized generation resources). These dockets also touch on issues related to concepts that are related to the value that solar provides but that are excluded in

²⁰ While introducing a bidding process for developers could lower costs in the short run, the level of the cap set is an unprincipled approach for our state’s energy system in the long run because the cap is not based on the value of the resource to the system. The cap 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.

²¹ New York Public Service Commission staff. (Dec. 12, 2018.) Whitepaper Regarding Future Value Stack Compensation, Including for Avoided Distribution Costs. Case 15-E-0751. Retrieved from: <http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B5DE69B8A-D3FB-44BA-95C0-7B4EB4FFCAAF%7D>

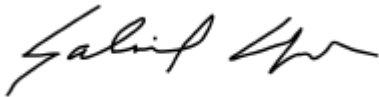
²² Carlile, P. R. (2002). A pragmatic view of knowledge and boundaries: Boundary objects in new product development. *Organization science*, 13(4), 442-455.

the current VOS, such as reliability, resiliency, avoided distribution O&M, voltage support, and power quality support. Other studies have attempted to quantify these values.²³

Given its potential impact in shaping a large amount of third-party investment in DERs, and its potential for linking together distinct proceedings, the VOS deserves specific attention. In our view, it is “worth it” to spend significant deliberative energy on continuously refining the VOS and other price signals so that investment in DERs can grow to meet system needs in a way that can be most beneficial to the public in the short- and long-run.

Thank you for this opportunity to comment. If you have any questions regarding the information or opinions provided in this filing, please contact me at 612-626-3292 or gabechan@umn.edu.

Sincerely,



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²³ ICF. (May 2018). Review of Recent Cost-Benefit Studies Related to Net Metering and Distributed Solar. Prepared for: The U.S. Department of Energy. Retrieved from https://www.icf.com/-/media/files/icf/reports/2019/icf-nem-meta-analysis_formatted-final_revised-1-17-193.pdf