414 Nicollet Mall
Minneapolis, MN 55401

**PUBLIC DOCUMENT –
NOT PUBLIC DATA EXCISED**

August 2, 2019

—Via Electronic Filing—

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

RE: PETITION
VALUE OF SOLAR METHODOLOGY
DOCKET NO. E999/M-14-65

Dear Mr. Wolf:

Northern States Power Company, doing business as Xcel Energy, submits the enclosed Petition to the Minnesota Public Utilities Commission requesting a modification to the state's Value of Solar (VOS) methodology.

Portions of Attachment A have been marked as "Not Public" pursuant to Minn. Stat. §13.37, subd. 1(b). This information has been marked as Confidential by the developer, thus we have designated the information as being Not Public.

Pursuant to Minn. Stat. §216.17, subd. 3, we have electronically filed this document with the Minnesota Public Utilities Commission, and copies have been served on the parties on the attached service list. Please contact Nick Paluck at (612) 330-2905 or Nick.Paluck@xcelenergy.com or me at (612) 330-7681 or Lisa.R.Peterson@xcelenergy.com if you have any questions regarding this filing.

Sincerely,

/s/

LISA R. PETERSON
MANAGER, REGULATORY ANALYSIS

Enclosures
c: Service List

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Katie J. Sieben	Chair
Dan Lipschultz	Commissioner
Valerie Means	Commissioner
Matthew Schuerger	Commissioner
John A. Tuma	Commissioner

IN THE MATTER OF ESTABLISHING A DISTRIBUTED SOLAR VALUE METHODOLOGY UNDER MINN. STAT. 216B.164, SUBD. 10 (E) AND (F)

DOCKET NO. E999/M-14-65

PETITION

INTRODUCTION

Northern States Power Company, doing business as Xcel Energy, submits this Petition to the Minnesota Public Utilities Commission requesting a modification to the state's Value of Solar (VOS) methodology.

As discussed in this Petition, there is now substantial evidence that the Company's concerns with the methodology have come to pass. According to the Company's preliminary calculation, the methodology produces a 2020 levelized rate of $.2484 per kWh. This result more than doubles the 2019 rate of $.1109 per kWh, and such an extreme result is unreasonable, unrepresentative, and clearly falls outside of the public interest. By contrast, applying the Company's proposal, the resulting rate is $.1132 per kWh, a stabilizing outcome that provides a modest increase over the prior year's rate.

The volatility in the annual calculation is now an observed phenomenon that requires correction. To formally resolve this concern and to provide a constructive path forward for the annual cycle of rate updates, the Company submits this request to modify one component discussed at pages 34, 35, and 36 of the Department of Commerce's April 10, 2014 *Minnesota Value of Solar: Methodology*.

The Company brings forth its Petition following a series of procedural steps and with significant record development on the topic of the methodology's avoided distribution capacity cost component. These steps include:

- introducing the Company's concern with the potential for inaccuracy and volatility rooted in the methodology,

- demonstrating the potential for volatile mathematical outcomes,
- developing an alternative means of deriving the avoided distribution capacity cost input,
- sharing the alternative concept with stakeholders and seeking input,
- submitting a compliance filing on the alternative concept, and finally,
- observing extreme results in the preliminary calculation of the 2020 rate.

We believe the Commission must act on the Company's proposal in order to ensure the VOS rate is derived from a more representative value and to stabilize the mathematical outcome of the Department's methodology. We understand that many parties, including the Company, are interested in potential modifications to other aspects of the methodology. The Company believes it is reasonable to reopen the full methodology, with a goal of refining it in total by 2021. Recognizing the magnitude of public resources required for such an undertaking, however, the Company believes a full revisitation of the methodology should be reserved for a later phase, and the Commission should directly take up the Company's more narrow and urgent request.

In this Petition, we describe the origins of the statewide VOS, including the Department's methodology and subsequent regulatory actions related to it. We also describe the results of the Company's preliminary calculation of the 2020 VOS rate and the evidence this calculation provides for needed changes to the methodology. Finally, we describe the modification to the Department's methodology the Company believes will deliver stability and increased representativeness to the resulting values.

I. SUMMARY OF FILING

A one-paragraph summary is attached to this filing pursuant to Minn. R. 7829.1300, subp. 1.

II. SERVICE ON OTHER PARTIES

Pursuant to Minn. R. 7829.1300, subp. 2, the Company has served a copy of this filing on the Office of the Attorney General – Antitrust and Utilities Division. A summary of the filing has been served on all parties on the enclosed service lists for Docket Nos. E999/M-14-65 and E002/M-13-867.

III. GENERAL FILING INFORMATION

Pursuant to Minn. R. 7829.1300, subp. 3, the Company provides the following information.

A. Name, Address, and Telephone Number of Utility

Northern States Power Company doing business as:
Xcel Energy
414 Nicollet Mall
Minneapolis, MN 55401
(612) 330-5500

B. Name, Address, and Telephone Number of Utility Attorney

James R. Denniston
Assistant General Counsel
Xcel Energy
414 Nicollet Mall, 401 – 8th Floor
Minneapolis, MN 55401
(612) 215-4656

C. Date of Filing

The date of this filing is August 2, 2019. The Company requests the approval of a modification to the VOS Methodology to take effect upon Commission Order so that it can be applied beginning with the 2020 VOS Vintage Year Bill Credit Rate in the community solar garden program.

D. Statute Controlling Schedule for Processing the Filing

This Petition falls within the definition of a miscellaneous filing under Minn. R. 7829.0100, subp. 11, since no determination of Xcel Energy's general revenue requirement is necessary.

E. Utility Employee Responsible for Filing

Lisa Peterson
Manager, Regulatory Analysis
Xcel Energy
414 Nicollet Mall, 401 – 7th Floor
Minneapolis, MN 55401
(612) 330-7681

IV. MISCELLANEOUS INFORMATION

Pursuant to Minn. R. 7829.0700, the Company requests that the following persons be placed on the Commission's official service list for this proceeding:

James R. Denniston	Lynnette Sweet
Assistant General Counsel	Regulatory Administrator
Xcel Energy	Xcel Energy
414 Nicollet Mall	414 Nicollet Mall
Minneapolis, MN 55401	Minneapolis, MN 55401
james.r.denniston@xcelenergy.com	regulatory.records@xcelenergy.com

Any information requests in this proceeding should be submitted to Ms. Sweet at the Regulatory Records email address above.

V. BACKGROUND

A. The Minnesota Value of Solar Statute

The Legislature delegated the development of the VOS methodology to the Department of Commerce and its annual calculation to the utility. Minn. Stat. § 216B.164 Subd. 10 states at (e) and (h):

> (e) The department must establish the distributed solar value methodology in paragraph (c), clause (1), no later than January 31, 2014. The department must submit the methodology to the commission for approval. The commission must approve, modify with the consent of the department, or disapprove the methodology within 60 days of its submission. When developing the distributed solar value methodology, the department shall consult stakeholders with experience and expertise in power systems, solar energy, and electric utility ratemaking regarding the proposed methodology, underlying assumptions, and preliminary data.
>
> […]
>
> (h) The utility shall recalculate the alternative tariff on an annual cycle, and shall file the recalculated alternative tariff with the commission for approval.

B. Commission Action on Value of Solar

The Department developed the methodology and submitted it for Commission approval on January 31, 2014.[1] The Commission approved the methodology on April 1, 2014 and required the Company to calculate the rate using the approved methodology on an annual basis.[2] No other Minnesota utility is required to file an annual VOS calculation. In its Order, the Commission modified the avoided distribution capacity cost component, requiring that it be set to zero, rather than producing a negative value, if the distribution peak load growth rate was a negative number.[3]

The Commission later ordered the Company to migrate the subscriber purchase price in the community solar gardens program from the Applicable Retail Rate (ARR) to the VOS for new projects.[4] The Company's community solar garden program, the largest such program in the country, is Minnesota's only program with a tariffed VOS rate in effect.

The Commission has made other modifications to the Company's VOS calculation, including in its March 26, 2018 Order, where it required Commission-approved environmental values to be used as inputs[5], and later in its November 16, 2018 Order, where it adopted a 1.5 cent per kWh residential adder for vintage years 2019 and 2020.[6]

The Company believes the Commission can act on the Company's Petition based on the record developed in the community solar gardens proceeding, including the Company's May 1, 2019 Compliance Filing. The Company's May 1 Compliance Filing, included here at Attachment A, describes the origins of the proposed modification to the Department's methodology and this background information is not restated here. The Company is aware that, as of the date of this filing, the Commission has issued a Notice of Extended Comment Period in order to receive

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[1] Minnesota Value of Solar: Methodology. Prepared for the Department of Commerce, Division of Energy Resources by Clean Power Research, January 31, 2014. *In the Matter of Establishing a Distributed Solar Value Methodology under Minn. Stat. § 216B.164, subd. 10 (e) and (f),* Docket No. E999/M-14-65.
[2] Order Approving Distributed Solar Value Methodology, April 1, 2014 and Order Denying Reconsideration May 16, 2014. *In the Matter of Establishing a Distributed Solar Value Methodology under Minn. Stat. § 216B.164, subd. 10 (e) and (f),* Docket No. E999/M-14-65.
[3] See order point 1(b) of the April 1, 2014 Order.
[4] Order Approving Value of Solar rate for Xcel's Solar Garden Program, Clarifying Program Parameters, and Requiring Further Filings, September 6, 2016. Docket No. E002/M-13-867.
[5] Order approving Xcel's Update to the 2018 System-Wide Value of Solar Tariff Rate with Modifications, March 26, 2018. Docket No. E002/M-13-867.
[6] Order Adopting Adder and Setting Reporting Requirements, November 16, 2018. Docket No. E002/M-13-867.

Reply Comments on the Company's Compliance Filing by August 19, 2019.[7] The Company separately Petitions for the change to the methodology to provide an expeditious path for Commission review, but is open to any procedure that enables a timely fix to the matter at hand. The Company believes there is no barrier to adopting methodology changes prior to the end of the calendar year and to enable the annual cadence of rate updates to proceed uninterrupted as anticipated by the Legislature.

C. Consent of the Department of Commerce

The Company understands the modification requested here is made with the consent of the Department, as required by the statute. The Department was supportive of this modification one year ago when reviewing the 2019 VOS calculation. On December 14, 2018, the Department stated,

> With respect to the 2019 system-wide VOS, the Department recommends the Commission adopt Xcel's proposal with the following modification: (1) adopt the use of the proposed avoided distribution cost methodology for calculating the system-wide cost component. Calculate the estimated capacity cost per kW using two historical and three forecasted years of capacity spending and capacity additions.[8]

In its recent Comments on this topic, the Department again recommends that the Commission approve the Company's proposed avoided distribution cost methodology for calculating the VOS.[9] In its evaluation, the Department noted that the Company's proposal reflects the Department's recommendation to use a combination of historical and forecasted distribution capacity additions and costs, rather than just forecasted information as originally proposed. The Department also stated that it did not object to the proposed 50 percent deferral factor. We believe the Department's support for modifying the avoided distribution capacity cost component for two consecutive years establishes the requisite consent for the Commission to modify the methodology.

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[7] Notice of Extended Comment Period. July 23, 2019. Docket No. E002/M-13-867.
[8] Department of Commerce Reply Comments, December 14, 2018. Docket No. E002/M-13-867.
[9] Comments of the Minnesota Department of Commerce, July 19, 2019, Docket No. E002/M-13-867.

VI. 2020 VALUE OF SOLAR

As discussed with solar garden developers, the Department, and others at the Company's July 31, 2019 stakeholder meeting, the Company recently completed its preliminary calculation of the rates for the 2020 vintage. The calculation yields a levelized rate of approximately $.2484 per kWh, or, stated differently, would expose all customers to a purchase price of approximately $248 per MWh for solar garden output. For reference, the levelized rate for the 2019 vintage is approximately $111 per MWh and the levelized cost of utility scale solar is approximately $40 per MWh.[10]

The driver of the substantial increase over 2019 levels is the avoided distribution capacity cost input, the component at the subject of this Petition. Under the current methodology, the input for avoided distribution capacity cost increases from $.0000 (2019) to $.1373 (2020). Therefore, the Commission's consideration of this matter is timely.

As a general matter, the Company believes the avoided distribution capacity costs input should be relatively stable year over year for the System Wide value. As shown in Table 1 below, however, the methodology has not borne out this expectation.

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

The Company will submit its annual calculation of the rate by September 1, 2019 as required by the Commission's March 22, 2019 Order.[11] As the resulting rate would violate the state's prohibition on rates that are unjust, unreasonable, insufficient, or unjustly discriminatory or preferential,[12] the Company will not request Commission approval of the calculation under the current methodology. In the Company's compliance filing we will supply the supporting documentation for the calculation under both methodologies and seek approval of the results under the Company's proposed methodology.

[10] Upper Midwest Integrated Resource Plan 2020-2034, July 1, 2019. Appendix F2, Table 18, Page 24 of 30. Docket No. E002/RP-19-368

[11] Order Approving Xcel's Update to the 2019 System-Wide Value of Solar Tariff Rate with Modifications. March 22, 2019. Docket No. E002/M-13-867.

[12] Minn. Stat. § 216B.23

According to our preliminary calculation, the 2020 result of the methodology proposed in this Petition is $.1132 per kWh (levelized). This rate is a $.0023 increase over 2019. The Company's compliance filing will propose to make this rate effective January 1, 2020. Attachment B to this Petition highlights the Company's proposed Avoided Distribution Capacity Cost Calculation.

VII. PROPOSED METHODOLOGY MODIFICATION

The Company seeks a modification to the VOS methodology that is narrowly tailored to produce avoided distribution cost values that are more representative of the Company's actual avoided costs than those yielded under the current methodology. The Company's proposed modification is provided as Attachment C to this Petition, and addresses the Avoided Distribution Capacity Cost in the Methodology at pages 34-36.

As stated in our May 1, 2019 Compliance Filing:

> 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.
>
> Without further modification, the methodology produces the maximum level of avoided distribution costs as it assumes that all capacity related distribution are avoided. However, since it is not clear if solar could be deployed in specific places on the distribution system or achieve the critical mass such that the distribution projects could be avoided or deferred by the actual solar installed, the Company proposes a 50% reduction factor to share this risk between solar providers and system customers.

It is the Company's expectation that, in addition to producing more representative values, the results under the proposal will also provide increased stability year over year. As the results under the Department's approved methodology yield unreasonable results for 2020, the public interest supports an efficient review and approval of the Company's Petition.

CONCLUSION

We appreciate the Commission's review of the Company's request to modify the Department of Commerce's VOS Methodology. As anticipated by the Company, the current methodology produces unrepresentative and unreasonable results. The Company has developed a narrowly tailored modification to stabilize the rate and yield more representative results. We respectfully request Commission action on this request so as to avoid interruption to the annual rate update as contemplated by the Legislature.

Dated: August 2, 2019

Northern States Power Company

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Katie J. Sieben	Chair
Dan Lipschultz	Commissioner
Valerie Means	Commissioner
Matthew Schuerger	Commissioner
John A. Tuma	Commissioner

IN THE MATTER OF ESTABLISHING A DISTRIBUTED SOLAR VALUE METHODOLOGY UNDER MINN. STAT. 216B.164, SUBD. 10 (E) AND (F)

DOCKET NO. E999/M-14-65

PETITION

SUMMARY OF FILING

Please take notice that on August 2, 2019, Northern States Power Company, doing business as Xcel Energy, submitted a Petition to modify the avoided distribution capacity cost component of the statewide Value of Solar methodology. As currently approved, the methodology produces unreasonable rates, and the Company requests the modification prior to the implementation of the 2020 vintage of the Value of Solar rate.

414 Nicollet Mall
Minneapolis, MN 55401

**PUBLIC DOCUMENT –
NOT PUBLIC DATA HAS BEEN EXCISED**

May 1, 2019

—Via Electronic Filing—

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

RE: COMPLIANCE FILING
COMMUNITY SOLAR GARDENS PROGRAM
DOCKET NO. E002/M-13-867

Dear Mr. Wolf:

Northern States Power Company, doing business as Xcel Energy, submits to the Minnesota Public Utilities Commission the enclosed compliance filing in compliance with the Minnesota Public Utilities Commission's March 22, 2019 ORDER APPROVING XCEL'S UPDATE TO THE 2019 SYSTEM –WIDE VALUE-OF-SOLAR TARIFF RATE WITH MODIFICATIONS. In particular, Order Point 2 which states:

> *2. The Minnesota Department of Commerce and Xcel shall solicit the opinions of the stakeholders regarding Xcel's proposed alternative method for calculating the VOS's avoided distribution cost, and Xcel shall file a more fully developed proposal no later than May 1, 2019.*

Portions of Attachment C have been marked as "Not Public" pursuant to Minn. Stat. §13.37, subd. 1(b). This information has been marked as Confidential by the developer, thus we have designated the information as being Not Public.

Pursuant to Minn. Stat. §216.17, subd. 3, we have electronically filed this document with the Minnesota Public Utilities Commission, and copies have been served on the parties on the attached service list. Please contact Nick Paluck at (612) 330-2905 or Nick.Paluck@xcelenergy.com or me at (612) 330-7681 or Lisa.R.Peterson@xcelenergy.com if you have any questions regarding this filing.

Sincerely,

/s/

LISA R. PETERSON
MANAGER, REGULATORY ANALYSIS

Enclosures
c: Service List

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Katie J. Sieben	Chair
Dan Lipschultz	Commissioner
Valerie Means	Commissioner
Matthew Schuerger	Commissioner
John A. Tuma	Commissioner

IN THE MATTER OF THE PETITION OF NORTHERN STATES POWER COMPANY FOR APPROVAL OF ITS PROPOSED COMMUNITY SOLAR GARDENS PROGRAM

DOCKET NO. E002/M-13-867

COMPLIANCE FILING

OVERVIEW

Northern States Power Company, doing business as Xcel Energy, submits this filing to the Minnesota Public Utilities Commission in compliance with the Commission's March 22, 2019 ORDER APPROVING XCEL'S UPDATE TO THE 2019 SYSTEM –WIDE VALUE-OF-SOLAR TARIFF RATE WITH MODIFICATIONS. The filing is made pursuant to Order Point 2, which states:

> *The Minnesota Department of Commerce and Xcel shall solicit the opinions of the stakeholders regarding Xcel's proposed alternative method for calculating the VOS's avoided distribution cost, and Xcel shall file a more fully developed proposal no later than May 1, 2019.*

We appreciate that the Commission has taken up this issue and asked the Company to address it. In this filing we set forth the background information that precedes the Company's current proposal, including the Company's prior communications with stakeholders regarding the volatility observed in the avoided distribution cost component of the Value of Solar methodology. We describe the alternative methodology proposed by the Company to address the observed volatility in this component. We describe our efforts to solicit stakeholder feedback on the methodology and we summarize the feedback received. Finally, we describe why we believe the Company has proposed a reasonable method for calculating this component.

COMPLIANCE FILING

I. BACKGROUND

On April 1, 2014, the Commission approved the Department of Commerce's proposed Value of Solar methodology.[1] The approved methodology sets forth a means of identifying a value to represent system-wide avoided distribution capacity costs based on actual 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.

A. Observation of the Component Volatility

Prior to the migration of the program from purchase prices under the Applicable Retail Rate to the Value of Solar rate, the Company raised its concerns with volatility of the avoided distribution capacity cost component in the calculation. We stated:[2]

> […T]here is demonstrable volatility in the VOS calculation that we raised as a possibility during the stakeholder input portion of the VOS methodology development but have only been able to recently identify with certainty. The cost per unit growth formula attributes capacity cost to the peak demand growth on the system. The combination of variable customer requirements and weather influences seasonal peak demand and creates volatile growth rates as can be observed in the company's calculations over the last three years.
>
> For example, we can demonstrate that foreseeable and expected range of growth scenarios in annual peak demand could force the levelized avoided distribution capacity component to land anywhere from $0.0000 per KWH to $0.3605+ per KWH. In turn, this variation would then drive a first-year VOS bill credit that could range from 9.95 to 38.90 (when using the 2016 VOS bill credit as the basis for the example) while the actual value of the solar generation to the system remains the same. A weather normalization adjustment alone will not resolve these extreme mathematical results.
>
> This scenario is verified in Attachment G *[ed. note: Attachment G is omitted]* by calculating the 2016 distribution capacity cost value on an 11 year basis where the cost per unit growth is calculated to be $16,792 compared to the negative result based on the methodology's prescribed ten year time frame. That distribution cost per unit growth value ($16,792) compares with the much smaller distribution cost per unit growth values filed of $336 and $928 included in previous Value of Solar calculations in 2014 and 2015, respectively. Figure 2 illustrates how the decrease in peak growth can result in exponentially higher distribution cost per unit growth.

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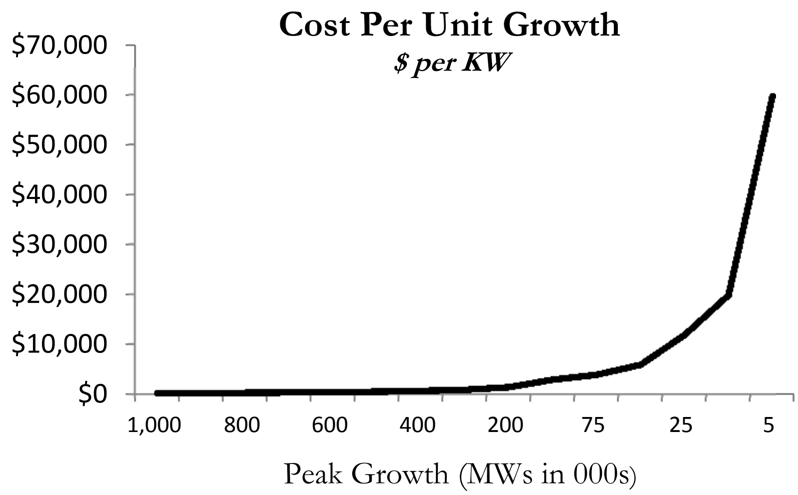
[1] *In the Matter of Establishing a VOS Distributed Solar Value Methodology under Minn. Stat. § 216B.164, subd. 10(3) and (f),* Docket No. E-999/M-14-65.
[2] Comments, April 1, 2016, Docket No. E002/M-13-867.

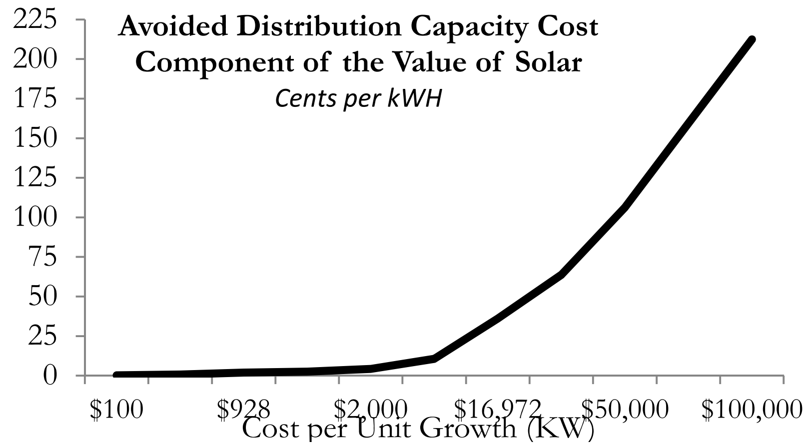
Figure 2.



The second step of the process is to input the distribution cost per unit growth into the Value of Solar model, which then derives the avoided distribution capacity cost. The $16,972 distribution cost per unit growth results in an avoided distribution capacity cost of 36.05 cents per KWH. Figure 3 illustrates the Value of Solar avoided distribution capacity cost that result from a range of distribution cost per unit growth.

At a minimum, the avoided distribution capacity cost should be limited to the actual cost of a KW of capacity and be based on actual avoided costs. At this time, we are uncertain whether we will also experience similar volatility in other VOS components. As shown in the illustration, the methodology as approved has the potential to produce unstable and unsettling results, cause customer confusion, and run counter to the idea that more cost can potentially be avoided in situations where peak demand growth is higher. For these reasons, we believe it is practical to correct for such volatility.

Figure 3.



As indicated above the Company has been concerned about Avoided Distribution Cost Component methodology since the beginning of the Value of Solar stakeholder discussions. At the heart of the Company's concern is the calculation of the Cost per unit growth whereby the current methodology requires utilities to divide the historical capacity-related distribution project costs by the weather normalized peak load growth over the past ten years. More specifically, the Company is concerned in situations where the calculation results in narrowly positive peak demand growth over the ten-year period. This is a valid concern because weather-normalized peak demand varies from year to year and our experience has shown the growth to be negative three of the five years in which the VOS has been calculated. The negative results illustrate the fact that a narrowly positive growth is a plausible result. In fact, in one of those negative growth years, the growth was only narrowly negative (2,997 kW relative to peak demand of 6,161,053 kW). Had the growth instead been positive value of 2,997 kW, the cost per unit growth calculation would have yielded a result $94,857 per kW. Inserting the $94,857 per kW into the table 14 Avoided Distribution Cost of the VOS calculation would have driven an Avoided Distribution cost component of $2.14 per kWh or $2,140 per MWh. This result is not a reasonable, nor is it an accurate reflection of the avoided distribution project costs.

*****

B. Alternate Methodology Introduced

The Company brought its suggestion on a correction to this component to the Department of Commerce. The Department acknowledged in its VOS compliance review letter that declining peak demand growth had produced a zero value for avoided distribution component.[3] On November 14, 2018, the Company and the Department jointly introduced the alternate methodology to the Solar*Rewards

[3] Department of Commerce, October 24, 2018. Docket No. E002/M-13-867.

Community Workgroup in the context of the development of a locational value component to the Value of Solar.[4] This was the subject of a second stakeholder meeting facilitated by the Department on November 30, 2018.

On December 14, 2018, the Department filed Reply Comments reporting on the status of stakeholder discussions to address avoided distribution costs in the methodology, and again summarized the Company's proposal for an alternate methodology.[5] The Department recommended that the Commission adopt the use of the proposed alternative method for calculating avoided distribution costs modified to use two historical and three forecasted years of capacity spending and capacity additions.

II. PROPOSED ALTERNATE METHODOLOGY

The Company appreciates that now, with actual data to validate prior concerns raised about this component, the Commission has asked the Company to revisit the avoided distribution capacity cost component. The Company's alternative proposal aims to improve the accuracy of the methodology while at the same time simplifying the calculation. It does so by dividing the avoided capacity-related distribution project costs by the avoided project capacity.[6]

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.

Without further modification, the methodology produces the maximum level of avoided distribution costs as it assumes that all capacity related distribution are avoided. However, since it is not clear if solar could be deployed in specific places on the distribution system or achieve the critical mass such that the distribution projects could be avoided or deferred by the actual solar installed, the Company proposes a 50% reduction factor to share this risk between solar providers and system customers.

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[4] November 14, 2018 Stakeholder Meeting Minutes, February 19, 2019, Docket No. E002/M-13-867.
[5] Again, these discussions were in the context of considering a location-specific valuation methodology.
[6] We use the terms "deferrable" and "avoidable" interchangeably in the context of this alternate methodology. Both words as used here describe the costs identified for calculating the avoided distribution capacity costs in the VOS methodology.

Without a reduction factor, the Company believes our customers could pay twice for capacity-related distribution projects that are not deferred by the addition of Solar*Rewards Community projects. Therefore this measure appropriately balances the interest of Solar*Reward Community subscribers and our customers who pay for Solar*Reward Community energy.

Had the alternative methodology been approved for the 2019 VOS, the resulting calculation would have been as shown below in Table 1.

Table 1. Alternative Avoided Distribution Capacity Cost per kW

Year	New Dist. Capacity	Capital Cost - Capacity projects	Cost Per kW
	(MW)	($M)	
2016	125.2	$15.932	$127
2017	43.3	$10.270	$237
2018	76.8	$10.280	$134
2019	34.8	$3.945	$113
2020	52.4	$12.765	$244
Total	332.5	$53.192	$160

The data from two years of actual and three years of budgeted capacity-related distribution projects yielded $160 on a cost per kW basis. Applying the 50% deferral factor reduces this figure to $80 per kW. Table 2 details this calculation. Had the Company applied a value of $80 cost per kW into Table 15 of the 2019 VOS, the result would have been a 0.18 cent avoided distribution capacity cost component. This addition would have raised the levelized 2019 VOS from 11.09 to 11.27 cents per kWh.

Table 2. Effective Avoided Distribution Capacity Cost per kW

Distribution Cost per kW	$160
Deferral Reduction Factor	50%
Effective Avoided Distribution Cost per kW	$80

III. STAKEHOLDER OUTREACH AND FEEDBACK

Following the issuance of the Commission's March 22, 2019 Order, the Company provided a detailed summary of the proposed alternate methodology to stakeholders through the distribution list for the Solar*Rewards Community program.[7] To support stakeholders' efforts to understand and evaluate the alternate proposal, the Company included sample calculations for the previous five years applying the proposed methodology to produce the avoided distribution capacity cost component. The Company sought feedback from stakeholders on the alternate methodology in order to consider any feedback prior to making this compliance filing.

On April 9, the Company sent the following message to stakeholders:

> Solar*Rewards Community Stakeholders:
>
> Xcel Energy and the Department of Commerce seek input from Solar*Rewards Community stakeholders on the proposed alternative methodology to define the system-wide avoided distribution cost component of the Value of Solar. The alternative methodology proposal was first introduced at the November 11, 2018 S*RC Stakeholder Implementation Workgroup monthly meeting (see Attachment A for meeting handout), and was also the topic of a stakeholder meeting hosted by the Department of Commerce on November 30, 2018. In initial discussions this approach was considered for the system-wide and locational avoided distribution capacity cost methodologies. However, the current focus is to define a system-wide approach. The methodology for location-specific avoided distribution capacity costs will be discussed at a later date. Also, the initial proposal included 3 planning years; the Department later recommended the addition of 2 historical years in the analysis.
>
> The current methodology has produced volatile avoided distribution capacity cost results in the last five years of calculations, including negative value results in three of the five years where the next step in the methodology then requires a zero value assignment. 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 proposal for the system-wide avoided distribution capacity cost methodology is as follows:
>
> **Methodology timeframe**: Five year average including two years historical and three years of forecast.
>
> **Costs**: Sum of capital costs for all capacity-related distribution projects for all years in methodology timeframe.
>
> **kW**: Sum of capacity increase installed on distribution system through capacity-related distribution projects for all years in methodology timeframe.

[7] The summary excluded the deferral reduction factor.

System-wide Avoided Distribution Capacity Cost ($/kw) =

Cost: capital costs for capacity-related distribution projects over 5 years

divided by

kW: distribution system capacity increases over 5 years

An example of the proposed alternative methodology calculation is shown in Attachment B to this email using data that was available for 2019, and the results for both methodologies are shown below.

Current Method: Peak Growth Based		
VOS Vintage	System Distribution Cost $ per kW	Distribution Component Cents per kWh*
2015	$928	2.28
2016	$0	0.00
2017	$0	0.00
2018	$401	0.82
2019	$0	0.00

Alternative Method: Distribution Project Cost Based		
VOS Vintage	System Distribution Cost $ per kW	Distribution Component Cents per kWh*
2015**	$111	0.23
2016**	$104	0.21
2017**	$120	0.25
2018**	$82	0.17
2019**	$165	0.34
2019***	$160	0.33

*The conversion to kWh is based on the 2018 VOS input values.
** Based on 3 years of planning data
*** Based on 2 years of actual and 3 years of planning data

Please respond to this email with your input by April 16. Xcel Energy will consider all responses in its May 1, 2019 filing as directed by the March 22, 2019 MPUC Order.

Thank you,
Xcel Energy

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The Company includes the Attachments referenced in the email as Attachments A and B to this filing.

The responses received are summarized at Attachment C. Parties provided virtually no substantive feedback on the Company's proposed alternate methodology. Several developers requested the methodology be applied to provide a 2020 avoided distribution component, and the Company responded that the dataset for 2020 will not be available until later in 2019.

Developers declined to provide feedback on the Company's proposal until the 2020 rates are available and the 2019 Legislative Session has concluded. For example, MnSEIA notes that its perspective on the importance of getting this component "absolutely correct" is contingent upon whether administrative control of the program is transferred to the Department of Commerce. MnSEIA is hopeful of an outcome of the Legislative Session that includes a multiyear "averaging" of the VOS, a methodology that is itself based on a 25 year average and then de-escalated to produce individual year values.

Feedback from stakeholders included a suggestion to average the results of the current methodology from the past five years. Table 3 highlights the results of this suggestion as being significantly negative (-39.15 cents per kWh) due to three of the five years exhibiting negative peak growth rates.

Table 3. Current Avoided Distribution Cost Methodology

Current Method: Peak Growth Based		
VOS Vintage	System Distribution Cost per kW	Distribution Component Cents per kWh
2015	$928	2.28
2016	($770)	(1.58)
2017	($94,857)	(193.98)
2018	$401	0.82
2019	($1,610)	(3.29)
5-Year Average	($19,182)	(39.15)

Fresh Energy requested that the Company provide a discussion of how distribution investments are categorized as "capacity-related". The Company provided a response to this previously in Fresh Energy IR 10 in this matter, included here at Attachment D. The Company stated, in relevant part:

> 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.
>
> 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.

*****

Outside of the VOS calculation, the Company does not have a business need to develop a specific category of deferrable capacity-related distribution projects. The identification of deferrable project costs is generally based on the expertise of the distribution personnel with specialized knowledge of the system. Projects that are excluded from the deferrable capacity-related project list include those that are driven by:

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

We are open to working with the Department of Commerce to identify and provide further information if it is helpful to the Department's review of the Company's calculations.

IV. REASONABLENESS OF PROPOSED METHODOLOGY

The alternative avoided distribution cost proposed by the Company leverages actual and budgeted distribution project cost and capacity created for the avoided distribution cost per kW input. If solar projects were sited in optimal locations and sized with respect to the distribution capacity needs of the system, these distribution projects would be the best proxy for the avoided cost known to the Company. However, because solar projects will not always be sited in optimal locations or sized sufficiently to create a material impact, the Company believes that the deferral reduction factor is an appropriate tool to share project deferral risk between Solar*Rewards Community Subscribers and Fuel Clause paying customers. Therefore the Company believes its alternative calculation yields a more accurate result and is fair and reasonable to all VOS stakeholders.

CONCLUSION

We appreciate the Commission's interest in examining the Company's alternate proposal to the avoided distribution capacity cost component of the Value of Solar. While stakeholders were unable to provide input directly to the Company, we are hopeful that the Commission's standard Notice of Comment process may elicit some productive input.

Dated: May 1, 2019

Northern States Power Company

Avoided Distribution Component of the VOS

Current and Alternative System and Location Specific Methodology

Distribution Capacity Value - Dollars per KW

	Current Method: Peak Growth Based					Alternative Method: Cost Based				
VOS Vintage	2015	2016	2017	2018	2019	2015	2016	2017	2018	2019
System Distribution Cost per KW	$928	$0	$0	$401	$0	$111	$104	$120	$82	$165
Planning Area Cost per kW										
Minneapolis				$335	$0	$0	$149	$0	$0	$0
Minnetonka				$307	$13,553	$117	$118	$128	$54	$79
Edina				$261	$0	$0	$0	$53	$78	$74
South East				$115	$350	$104	$100	$97	$66	$185
Maple Grove				$156	$455	$414	$32	$69	$61	$0
Newport				$78	$192	$101	$17	$0	$85	$351
St. Paul				$27	$158	$26	$0	$0	$0	$0
North West				$159	$347	$66	$113	$147	$110	$160
White Bear Lake				$131	$465	$117	$257	$116	$107	$155

Distribution Capacity Value - Cents per kWh

	Current Method: Peak Growth Based					Alternative Method: Cost Based				
VOS Vintage	2015	2016	2017	2018	2019	2015	2016	2017	2018	2019
System Cost per kWh	2.28	0.00	0.00	0.82	0.00	0.23	0.21	0.25	0.17	0.34
Planning Area Cost per kWh										
Minneapolis				0.69	0.00	0.00	0.30	0.00	0.00	0.00
Minnetonka				0.63	27.72	0.24	0.24	0.26	0.11	0.16
Edina				0.53	0.00	0.00	0.00	0.11	0.16	0.15
South East				0.24	0.72	0.21	0.20	0.20	0.13	0.38
Maple Grove				0.32	0.93	0.85	0.06	0.14	0.13	0.00
Newport				0.16	0.39	0.21	0.03	0.00	0.17	0.72
St. Paul				0.06	0.32	0.05	0.00	0.00	0.00	0.00
North West				0.33	0.71	0.13	0.23	0.30	0.23	0.33
White Bear Lake				0.27	0.95	0.24	0.53	0.24	0.22	0.32

VOS Distribution Capacity Cost per kW - Minnetonka Area

A. Estimate the percentage of distribution cost that is deferrable per the VOS methodology

		Planning Area MN Electric Distribution Costs *Nominal*	**Percent Capacity Related**	**Planning Area Capacity Related Project Costs** *Nominal*	**2019 Inflation Adjustment** Inflation Rate 2.25%	**Planning Area Capacity Related Project Cost** *Adjusted for Inflation*
		(a)	(a / b)	(b)	(c)	(c * b) = (d)
1	2020	$0		$0	97.8%	$0
2	2019	$0	#DIV/0!	$0	100.0%	$0
3	2018	$2,499,221	82.6%	$2,064,203	102.3%	$2,110,648
4	2017	$7,448,045	40.7%	$3,030,685	104.6%	$3,168,600
5	2016	$11,765,484	64.2%	$7,550,839	106.9%	$8,072,074
6	2015	$9,296,046	7.3%	$674,232	109.3%	$736,992
7	2014	$4,261,234	-0.3%	($10,919)	111.8%	($12,204)
8	2013	$8,178,480	0.7%	$57,079	114.3%	$65,231
9	2012	$6,717,030	0.0%	$1,639	116.9%	$1,915
10	2011	$5,069,252	24.5%	$1,244,169	119.5%	$1,486,572
	2010-19 Total					$15,629,828

B. Identify Peak Demand Forecast/Historical 10-yr growth rate

		Planning Area Peak Data Minnetonka	**Planning Area KW Growth 2020 vs. 2011**	**Planning Area Average Annual Growth Rate**
1	2020	433,237	1,153	0.03%
2	2019	430,625		
3	2018	424,906		
4	2017	455,233		
5	2016	408,341		
6	2015	377,038		
7	2014	416,977		
8	2013	411,747		
9	2012	424,891		
10	2011	432,084		

C. Calulate Cost per kW Growth 2010-19

Distribution Cost	$15,629,828	(g)	From A
10yrs of kW Growth	1,153	(h)	From B
Cost per kW	$13,553	(i) = (g) / (h)	
Cost per kW (Inserted into Table 15)	$13,553	(j) = (i) unless (i) < 0, then 0	

VOS Distribution Capacity Cost per kW

(A) System actual cost per KWH (sum of planning areas)

Year	New Dist. Capacity	Capital Cost - Capacity projects
	(MW)	($M)
2018	76.800	$10.280
2019	34.800	$3.945
2020	52.400	$12.765
Total	164.000	$26.990
Cost per kW		$165

(B) Planning area actual cost per KW based on Anticipated Capital Capacitiy Related Investments

141 Minneapolis	#DIV/0!	144 SouthEast	$185	151 St. Paul	#DIV/0!
142 Minnetonka	$79	147 Maple Grove	#DIV/0!	154 NorthWest	$160
143 Edina	$74	150 Newport	$351	156 White Bear Lake	$155

141 Minneapolis

Year	New Dist. Capacity	Capital Cost - Capacity projects
	(MW)	($M)
2018	0.000	$0.119
2019	0.000	$0.000
2020	0.000	$0.850
Total	0.000	$0.969
Cost per kW		#DIV/0!

142 Minnetonka

Year	New Dist. Capacity	Capital Cost - Capacity projects
	(MW)	($M)
2018	26.000	$2.064
2019	0.000	$0.000
2020	0.000	$0.000
Total	26.000	$2.064
Cost per kW		$79

143 Edina

Year	New Dist. Capacity	Capital Cost - Capacity projects
	(MW)	($M)
2018	14.300	$1.279
2019	0.000	$0.000
2020	11.900	$0.650
Total	26.2	$1.929
Cost per kW		$74

144 SouthEast

Year	New Dist. Capacity	Capital Cost - Capacity projects
	(MW)	($M)
2018	21.600	$2.298
2019	0.000	$0.200
2020	14.000	$4.100
Total	35.6	$6.598
Cost per kW		$185

147 Maple Grove

Year	New Dist. Capacity	Capital Cost - Capacity projects
	(MW)	($M)
2018	0.000	$0.024
2019	0.000	$0.000
2020	0.000	$0.000
Total	0.0	$0.024
Cost per kW		#DIV/0!

150 Newport

Year	New Dist. Capacity	Capital Cost - Capacity projects
	(MW)	($M)
2018	14.900	$1.131
2019	0.000	$0.200
2020	0.000	$3.900
Total	14.9	$5.231
Cost per kW		$351

151 St. Paul

Year	New Dist. Capacity	Capital Cost - Capacity projects
	(MW)	($M)
2018	0.000	$0.200
2019	0.000	$0.000
2020	0.000	$0.250
Total	0.0	$0.450
Cost per kW		#DIV/0!

154 NorthWest

Year	New Dist. Capacity	Capital Cost - Capacity projects
	(MW)	($M)
2018	0.000	$3.015
2019	34.800	$3.545
2020	12.600	$1.015
Total	47.4	$7.575
Cost per kW		$160

156 White Bear Lake

Year	New Dist. Capacity	Capital Cost - Capacity projects
	(MW)	($M)
2018	0.000	$0.150
2019	0.000	$0.000
2020	13.900	$2.000
Total	13.9	$2.150
Cost per kW		$155

VOS Distribution Capacity Cost per kW

(A) System actual cost per KWH (sum of planning areas)

Year	New Distribution Capacity	Capital Cost - Capacity Related Projects
	(MW)	($M)
2016	125.200	$15.936
2017	43.300	$10.270
2018	76.800	$10.280
2019	34.800	$3.945
2020	52.400	$12.765
Total	332.500	$53.197
Cost per kW		$159.99

(B) Planning area actual cost per KW based on Anticipated Capital Capacitiy Related Investments

141 Minneapolis	#DIV/0!	144 SouthEast	$185	151 St. Paul	#DIV/0!
142 Minnetonka	$79	147 Maple Grove	#DIV/0!	154 NorthWest	$160
143 Edina	$74	150 Newport	$351	156 White Bear Lake	$155

141 Minneapolis

Year	New Dist. Capacity	Capital Cost - Capacity projects
	(MW)	($M)
2018	0.000	$0.119
2019	0.000	$0.000
2020	0.000	$0.850
Total	0.000	$0.969
Cost per kW		#DIV/0!

142 Minnetonka

Year	New Dist. Capacity	Capital Cost - Capacity projects
	(MW)	($M)
2018	26.000	$2.064
2019	0.000	$0.000
2020	0.000	$0.000
Total	26.000	$2.064
Cost per kW		$79

143 Edina

Year	New Dist. Capacity	Capital Cost - Capacity projects
	(MW)	($M)
2018	14.300	$1.279
2019	0.000	$0.000
2020	11.900	$0.650
Total	26.2	$1.929
Cost per kW		$74

144 SouthEast

Year	New Dist. Capacity	Capital Cost - Capacity projects
	(MW)	($M)
2018	21.600	$2.298
2019	0.000	$0.200
2020	14.000	$4.100
Total	35.6	$6.598
Cost per kW		$185

147 Maple Grove

Year	New Dist. Capacity	Capital Cost - Capacity projects
	(MW)	($M)
2018	0.000	$0.024
2019	0.000	$0.000
2020	0.000	$0.000
Total	0.0	$0.024
Cost per kW		#DIV/0!

150 Newport

Year	New Dist. Capacity	Capital Cost - Capacity projects
	(MW)	($M)
2018	14.900	$1.131
2019	0.000	$0.200
2020	0.000	$3.900
Total	14.9	$5.231
Cost per kW		$351

151 St. Paul

Year	New Dist. Capacity	Capital Cost - Capacity projects
	(MW)	($M)
2018	0.000	$0.200
2019	0.000	$0.000
2020	0.000	$0.250
Total	0.0	$0.450
Cost per kW		#DIV/0!

154 NorthWest

Year	New Dist. Capacity	Capital Cost - Capacity projects
	(MW)	($M)
2018	0.000	$3.015
2019	34.800	$3.545
2020	12.600	$1.015
Total	47.4	$7.575
Cost per kW		$160

156 White Bear Lake

Year	New Dist. Capacity	Capital Cost - Capacity projects
	(MW)	($M)
2018	0.000	$0.150
2019	0.000	$0.000
2020	13.900	$2.000
Total	13.9	$2.150
Cost per kW		$155

Organization	Requestor	Response to Request for Comments	Rcvd Date	Response	Response Date
Sunshare	David Amster-Olszewski	Hi Amber, Could you help me understand something. What was the system-wide avoided distribution cost component for the 2019 VOS, and what is the predicted system-wide avoided distribution cost component for the 2020 VOS? It's hard to look at the below request without putting some actual number to it. What is the impact to each of those year's VOS with the current system-wide avoided distribution cost component methodology and what is the impact to each of those year's VOS with the new methodology you propose below? Thank you, David	5-Apr	Hi David, The 2019 avoided distribution cost component is included in the email I sent (I highlighted the number in the email below for easy reference). The 2020 value is not available at this time, however we provide five years of avoided distribution cost history (2015 through 2019, and also in the email below) to provide context for stakeholders on this subject. Thanks! Amber	8-Apr
Novel Energy	Cliff Kaehler	What would the calculations be for 2020? Thanks Cliff	6-Apr	Hi Cliff, The 2020 value is not available at this time; however, we provide five years of avoided distribution cost history (i.e., 2015 through 2019 - included in the email below) to provide context for stakeholders on this subject. Thanks! Amber	8-Apr
Novel Energy	Cliff Kaehler	**[PROTECTED DATA BEGINS** **PROTECTED DATA ENDS]**	8-Apr	Hello, To date we have received several requests to provide the 2020 value for the proposed avoided distribution capacity credit. In order to keep all parties informed, we thought it would be appropriate to send our response to all parties on our Solar*Rewards Community stakeholders list. The 2020 value for the proposed avoided distribution capacity cost methodology is not known at this time, as the source dataset will not be available until the Company's budget is approved this summer. The Company has provided five years of avoided distribution cost history (2015 through 2019) for context on the proposed methodology. The Company will provide the 2020 avoided distribution capacity cost results at the July 31 stakeholder meeting to discuss the 2020 VOS, as well as in our September filing for the 2020 VOS. Thank you, Amber	9-Apr
Sunshare	David Amster-Olszewski	Hi Amber, I think it would be good for the group to at least coalesce around what the 2020 distributed cost component would be, in order to provide meaningful feedback to your query. Because that's in effect what's proposed to be changed. My understanding is that this figure could be calculated at this time, correct? I want to make sure as we consider our feedback we at least have agreement on how that rate would change at least one year forward. Thank you, David	8-Apr	Hello, To date we have received several requests to provide the 2020 value for the proposed avoided distribution capacity credit. In order to keep all parties informed, we thought it would be appropriate to send our response to all parties on our Solar*Rewards Community stakeholders list. The 2020 value for the proposed avoided distribution capacity cost methodology is not known at this time, as the source dataset will not be available until the Company's budget is approved this summer. The Company has provided five years of avoided distribution cost history (2015 through 2019) for context on the proposed methodology. The Company will provide the 2020 avoided distribution capacity cost results at the July 31 stakeholder meeting to discuss the 2020 VOS, as well as in our September filing for the 2020 VOS. Thank you, Amber	9-Apr
Novel Energy	Cliff Kaehler	Our response is the following: We can't really give any input without knowing the 2020 estimated VOS rate. After the stakeholder meeting where that is discussed, we will be prepared to talk through the different options. It's just tough to give an answer without all the necessary information. Hope your week is going well! Thanks Cliff	11-Apr	N/A	N/A
Fresh Energy	Allen Gleckner	Hi Amber – in your May 1 filing, we'd request that Xcel include an explanation of how it determines that distribution investments, both historical and forecasted, are categorized as "capacity-related", including any methodology to make that determination, as well as the amount and classification for investments in the historical and forecast period that are determined to be not capacity-related. It would be helpful to include this as an itemized spreadsheet in an appendix.	16-Apr	Thank you for your response!	16-Apr
Stoel Rives	Sara Bergan	Amber, Thank you for the opportunity to provide input on the Company's proposed alternative method for calculating the VOS avoided distribution cost value. The ability to provide effective feedback, however, is limited by the fact that the 2020 values under the current methodology are still unknown. If the Company is able to provide these numbers after the budget is approved this summer as indicated in your email below, we believe it would be much more efficient to wait until those figures are available and evaluate appropriate modifications at that time when we can all be focused on the same baseline information. Having this discussion now before Xcel is able to project values for 2020 and while the legislature is embroiled in various potentially consequential program changes, seems potentially hasty and premature. It might be different if the delay was much more substantial but in just a few months, the legislative session will have ended and it sounds like Xcel will be able to deliver more accurate 2020 values. If forced to suggest alternatives without the benefit of the 2020 values, the CSG Developer Group would suggest that the avoided distribution capacity cost value simply be averaged over a wide set of years to address the volatility. The group is curious to know, for example, what the average value would be from program inception through and inclusive of the current 2020 values. Likewise the group would be interested in exploring what averaging the VOS rate as a whole over a rolling multi-year period might do to rate stability. Although these and other changes may be worth exploring, it is very hard to recommend constructive changes without focusing on the most applicable set of numbers. Sent on behalf of the CSG Developer Group, Sara Bergan |Attorney STOEL RIVES LLP Direct: (612) 373-8819	16-Apr	N/A	

Organization	Requestor	Response to Request for Comments	Rcvd Date	Response	Response Date
MNSEIA	David Shaffer	The Minnesota Solar Energy Industries Association (MnSEIA) submits the following comments regarding Xcel's April 5th email request soliciting stakeholder feedback on its propose alteration to the Value of Solar (VOS) methodology. In short, MnSEIA opposes Xcel's new methodology. Further details are included below. I. NOW IS NOT THE TIME TO MAKE THIS CHANGE AND THIS PROCEEDING SHOULD BE TEMPORARILY STAYED. At the outset MnSEIA would like to state that there seem to be different ways to calculate this value and that currently we view all options as viable. A change may be necessary at some point, but we are not yet convinced that Xcel's approach comes close at approximating the actual benefit distributed solar brings to Xcel's distribution capacity. There is not yet enough information to help make this decision on how we should change the distribution capacity component. a. The Legislature Is Considering Substantial Changes That May Moot This Issue Entirely, Or Alter MnSEIA's Opinion Of What An Acceptable Distribution Capacity Component Would Be. While MnSEIA appreciates that Xcel is seeking to submit a May 1, 2019 filing to the Commission, pursuant to the March 22, 2019 Order, MnSEIA seeks to convey to Xcel - and hopes Xcel reiterates this to the Commission - that now is an awkward time to discuss this item. While MnSEIA has broad opinions at this time, they are liable to change with the outcome of the legislative session. Currently there are several underlying bills that are bundled into bigger omnibus bills that would really impact our opinions on the need for a change to the distribution capacity component and what the change would look like. Specifically, in the Senate Energy Omnibus bill there is a provision to eliminate the Community Solar Garden program's reliance on the Value of Solar altogether. It would result in a 25MW program cap with a Request for Performance model to determine the actual price to be paid CSG subscribers for the energy and capacity sold to the utility. If this bill were to come to fruition, then this issue is altogether mooted. Similarly on the House side, there is a positive Community Solar Gardens bill that would, among other things, require a three year averaging of the VOS and would put the administration of the VOS methodology in the hands of the Department. If these provisions were to pass, MnSEIA may have a different opinion on how important it is to get this actual variable, which is one of many in the VOS methodology value stack, absolutely correct. More importantly, with a 3 year average in place MnSEIA would even question whether a transition away from the current distribution capacity methodology is even warranted, as the volatility of this component would be substantially reduced through the averaging process. MnSEIA would thus suggest that Xcel file in its May 1, 2019 filing an acknowledgement that the need for transitioning from the current distribution capacity methodology, and how should be done, is heavily dependent on the outcome of this legislative session. Furthermore, we request that any comment period or decision rendered on this topic, should be made only after the legislative session, and any subsequent special sessions, have concluded. b. MnSEIA Believes There Is A Current Lack Of Information Available To Determine Whether There Is A Problem With This VOS Component And To What Extent It Should Be Changed, But That This Information Will Be Available This Summer. At the outset MnSEIA would like to highlight that Xcel has been unwilling or unable to produce an estimate for the 2020 distribution capacity component. This piece of information i important to really address whether a problem exists and to what extent. Xcel seems to suggest that it wants to move away from the current approach to avoid volatility, but the industry is the stakeholder group most impacted by the current approach's volatility since our businesses depend on this rate. But while we are not entirely happy with the current model, it is better than the approach Xcel is devising with the information available. Even a simple 5 year average would be better than Xcel's current proposal. That is to say, if you average the current methodology's distribution component, which was 2.28 Cents per kWh in 2015, 0 Cents per kWh in 2016 and 2017, 0.82 Cents per kWh in 2018 and again 0 Cents per kWh in 2019, then the average value of the price per distribution component is .62 Cents per kWh. However, if Xcel's approach was applied, then the average over the same five years for this component would be .31 cents per kWh. It would be half as much on average. While the Cents per kWh is important and we have spoken to it above, MnSEIA is not advocating for an approach that yields the most money. We do respect a desire for less volatility, if it were to yield similar values. If, for instance, the 2020 Distribution Component came in again at 0 Cents per kWh, then it would lower the average from .62 cents per kWh to .52, which is starting to get closer to the Xcel average. It would also further illustrate that there are boom and bust years to this program because of this particular component. In our November our filed comments included the following statement about this issue: Concurrent with the Commission's consideration of the 2019 VOS is a conversation around the avoided distribution capacity value component and locational value for future gardens. The current 2019 VOS has an effective distribution capacity value of $0. This is a big part of the reason the 2019 VOS dropped 13% in a single year. And it is a strange result, given that Xcel itself has spent $199 million on capacity-related upgrades to its Minnesota distribution system over the past ten years.8 (In other words, Xcel averages almost $20 million per year on capacity related distribution upgrades, but is awarding zero avoided costs savings to 2019-vintage VOS projects.). At the same time, the VOS methodology gives zero value to the $42 million in distribution upgrades that CSG Developers have purchased for the utility (through June 2018), and zero value to the $8.2 million in distribution engineering studies that CSG developers have paid to date – despite the value that both will provide to the distribution system over the next 25 years.1 So our initial understanding of any change to this distribution capacity component is that the methodology would better recognize the value distributed solar brings to Xcel's distribution system. Without the 2020 number it is hard to know whether 1) we are just uncomfortable with an approach that gets closer to that real number, 2) whether Xcel's valuation is reasonable but requires some minor modifications, or 3) whether Xcel's approach actually further devalues a distribution capacity credit that we feel is already woefully inadequate, requiring either a new way to get at this valuation or the retention of the current methodology. Xcel has stated that it intends to release the results for the 2020 distribution capacity component at the July 31, 2019 SRC meeting and to discuss it in their 2020 VOS filing in September. MnSEIA would like to stay Xcel's recommendation to the Commission on this point, or at least stay the comment period, until this number is made available. II. XCEL'S METHODOLOGY IS FLAWED FOR REASONS WE HAVE ALREADY ARTICULATED IN THE NOVEMBER STAKEHOLDER MEETING. At the November stakeholder meeting where MnSEIA, other developer members, Xcel and the Department of Commerce met to discuss how to improve Xcel's distribution capacity component. At that time, Xcel was proposing a 5-year look forward approach to calculating the distribution capacity component as opposed to a partial look forward and look back, as it is doing today. MnSEIA and our members argued that a 25-year look forward makes significantly more sense, as the VOS is used for 25 year contracts. We argued this same point in relation to the current methodology in our November commentary. If Xcel intends to upgrade its distribution system and the addition of a new CSG might delay that upgrade during the CSG's life-span, a garden that is online during the time should receive credit for the cost deferral. MnSEIA and our members further argued that some valuation should be placed on the upgrade costs that developers are paying to improve Xcel's substations and equipment. The counter argument, which we've heard in this meeting and elsewhere, is that the upgrades are only needed because a CSG is being added to the grid. The crux of the argument is that the upgrades would otherwise not be made. Certainly this is true at times - but it is not true in all cases. Take for instance when Xcel will have to upgrade an old transformer that is close to where the CSG is to be added. If the developer were to add a new transformer to interconnect their garden, then Xcel would save money on a piece of equipment it knows it will need to upgrade shortly. This is a clear cost savings for the utility and its ratepayers, but it is not included in the current VOS methodology nor is it included in the proposed methodology. Presumably upgrades like this have occurred somewhat frequently with over 500MW of interconnected gardens. We do have additional challenges with Xcel's distribution capacity component, but because our initial challenges with Xcel's methodology were not further considered, we intend to share those only during a formal PUC comment period. -- David Shaffer Executive Director MNSEIA	16-Apr	N/A	

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☐ **Public Document – Trade Secret Data Excised**
☒ **Public Document**

Xcel Energy			
Docket No.:	E002/M-13-867		
Response To:	Fresh Energy	Information Request No.	10
Requestor:	Allen Gleckner		
Date Received:	October 12, 2017		

Question:

Re: VOS Compliance Filing, Attachment B – Distribution Capacity Cost:

Regarding the "location-specific" distribution capacity cost calculations

a) Please describe how Xcel developed the nine distribution planning areas, including how this process complies with the Value of Solar Methodology's direction that "The distribution cost VOS should be calculated for each distribution planning area, defined as the minimum area in which capacity needs cannot be met by transferring loads internally from one circuit to another."[1]

b) Please explain how Xcel determined the percentage of planning area investment that is "capacity-related". Is this method consistent with the class cost of serve study provided in the most recent rate case?

c) For the "system-wide" distribution capacity cost component, the historical 10-year peak demand growth rate (in kw) is calculated for the years 2007-2016. For the distribution capacity cost component for the nine planning areas, the historical 10-year peak demand growth rate (in kw) is calculated for the years 2010-2019, where 2018 and 2019 are estimates. Please explain why Xcel is using different date ranges for determining historical 10-year peak growth.

[1] At 36.

<u>Response:</u>

a) The Value of Solar calculations were based on the distribution planning areas which are generally defined geographically and have been in place for 20+ years. The distribution planning areas align with our service center areas for the most part but there are some variances. Service center areas are defined geographically and have engineering, design, construction and other resources assigned to them. The distribution planning areas are defined by substation and some substation feeders will cross over more than one service center area. Given that most of our territory can transfer load from one circuit to another, defining distribution planning areas as the minimum area in which capacity needs cannot be met by transferring loads would not result in additional planning areas. In addition, costs more granular than the areas provided are not available.

b) As can be found by referring to the live copy of Attachment B – 2018 Distribution Capacity Values that was submitted with our October 2nd filing in this docket, the percentages referenced in the question are calculated by dividing the Capacity Related Project Cost (column F) by Total Distribution project costs (column D). This formula is represented generally at the top of the percentage calculation column. To find the cell inputs for each specific percentage, its formula can be found by clicking on the Excel cell containing the percentage.

   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.

   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.

c) The Company interpreted the Department's methodology as requiring different date ranges for the two methodologies. On page 34 of the Department's methodology for system wide avoided costs, it refers to using actual data from each of the last 10 years. Then, on page 37 of the Department's methodology for location specific avoided costs, it refers to using budgetary engineering cost estimates for the planning horizon. Our planning horizon is three years. The Company communicated the guidance employed in calculating the system-wide and location-specific distribution values in the Company's cover letter of the 2018 VOS submission. Below is the excerpt from our cover letter of the 2018 VOS submission.

Selected text from the Company's 2018 VOS cover letter:

Attachment B contains the calculation of the avoided distribution capacity, including location-specific avoided costs per ordering point 4 of the Commission's September 6, 2016 Order in this docket. The company employs historical cost and peak demand data for the system-wide method and uses a combination of historical and forecast cost and peak demand data to comply with the location-specific method as indicated by the methodology. To create the location-specific avoided distribution cost the Company employed the following references from the VOS Methodology.

From page 36 of the Department's VOS Methodology[2]:

System-wide Avoided Costs
"Cost per unit growth ($ per KW) is calculated by taking all of the total deferrable cost for each year adjusting for inflation, and dividing by the KW increase in peak annual load over the 10 years"

Location-Specific Avoided Costs
"When calculating the location-specific costs, the calculation should follow the same method of the system-wide avoided cost method, but use local technical and cost data.

- "The distribution cost VOS should be calculated for each distribution planning area…"
- "Anticipated capital costs should be evaluated based on capacity related investments only (as above) using budgetary engineering cost estimates…"

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[2] Docket No. E999/M-14-65; IN THE MATTER OF ESTABLISHING A DISTRIBUTED SOLAR VALUE METHODOLOGY UNDER MINN. STAT.§ 216B.164, SUBD. 10 (E) AND (F); Minnesota Value of Solar: Methodology (Department); April 2, 2014.

Preparer: Meghan Tisdell/Nick Paluck
Title: Senior Engineer/Rate Consultant
Department: System Planning Minnesota/Regulatory Analysis
Telephone: 763.493.1850/612.330.2905
Date: October 23, 2017

CERTIFICATE OF SERVICE

I, Jim Erickson, hereby certify that I have this day served copies of the foregoing document on the attached list of persons.

xx by depositing a true and correct copy thereof, properly enveloped with postage paid in the United States mail at Minneapolis, Minnesota

xx electronic filing

Docket No. E002/M-13-867

Dated this 1st day of May 2019

/s/

____

Jim Erickson
Regulatory Administrator

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Ross	Abbey	ross.abbey@us-solar.com	United States Solar Corp.	100 North 6th St Ste 222C Minneapolis, MN 55403	Electronic Service	No	OFF_SL_13-867_Official
Michael	Allen	michael.allen@allenergysolar.com	All Energy Solar	721 W 26th st Suite 211 Minneapolis, Minnesota 55405	Electronic Service	No	OFF_SL_13-867_Official
David	Amster Olzweski	david@mysunshare.com	SunShare, LLC	1151 Bannock St Denver, CO 80204-8020	Electronic Service	No	OFF_SL_13-867_Official
Sara	Baldwin Auck	sarab@irecusa.org	Interstate Renewable Energy Council, Inc.	PO Box 1156 Latham, NY 12110	Electronic Service	No	OFF_SL_13-867_Official
Laura	Beaton	beaton@smwlaw.com	Shute, Mihaly & Weinberger LLP	396 Hayes Street San Francisco, CA 94102	Electronic Service	No	OFF_SL_13-867_Official
Kenneth	Bradley	kbradley1965@gmail.com		2837 Emerson Ave S Apt CW112 Minneapolis, MN 55408	Electronic Service	No	OFF_SL_13-867_Official
Michael J.	Bull	mbull@mncee.org	Center for Energy and Environment	212 Third Ave N Ste 560 Minneapolis, MN 55401	Electronic Service	No	OFF_SL_13-867_Official
Jessica	Burdette	jessica.burdette@state.mn.us	Department of Commerce	85 7th Place East Suite 500 St. Paul, MN 55101	Electronic Service	No	OFF_SL_13-867_Official
Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1800 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_13-867_Official
Arthur	Crowell	Crowell.arthur@yahoo.com	A Work of Art Solar	14333 Orchard Rd. Minnetonka, MN 55345	Electronic Service	No	OFF_SL_13-867_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Timothy	DenHerder Thomas	timothy@cooperativeenergyfutures.com	Cooperative Energy Futures	3500 Bloomington Ave. S Minneapolis, MN 55407	Electronic Service	No	OFF_SL_13-867_Official
James	Denniston	james.r.denniston@xcelenergy.com	Xcel Energy Services, Inc.	414 Nicollet Mall, Fifth Floor Minneapolis, MN 55401	Electronic Service	No	OFF_SL_13-867_Official
Ian	Dobson	residential.utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	Yes	OFF_SL_13-867_Official
Jason	Edens	jason@rreal.org	Rural Renewable Energy Alliance	3963 8th Street SW Backus, MN 55435	Electronic Service	No	OFF_SL_13-867_Official
Betsy	Engelking	betsy@geronimoenergy.com	Geronimo Energy	7650 Edinborough Way Suite 725 Edina, MN 55435	Electronic Service	No	OFF_SL_13-867_Official
John	Farrell	jfarrell@ilsr.org	Institute for Local Self-Reliance	1313 5th St SE #303 Minneapolis, MN 55414	Electronic Service	No	OFF_SL_13-867_Official
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 280 Saint Paul, MN 551012198	Electronic Service	No	OFF_SL_13-867_Official
Matthew D.	Forsgren	mforsgren@greeneespel.com	GREENE ESPEL PLLP	222 S. Ninth Street, Suite 2200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_13-867_Official
Nathan	Franzen	nathan@geronimoenergy.com	Geronimo Energy	7650 Edinborough Way Suite 725 Edina, MN 55435	Electronic Service	No	OFF_SL_13-867_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Hal	Galvin	halgalvin@comcast.net	Provectus Energy Development llc	1936 Kenwood Parkway Minneapolis, MN 55405	Electronic Service	No	OFF_SL_13-867_Official
Allen	Gleckner	gleckner@fresh-energy.org	Fresh Energy	408 St. Peter Street Ste 220 Saint Paul, Minnesota 55102	Electronic Service	No	OFF_SL_13-867_Official
Sean	Gosiewski	sean@afors.org	Alliance for Sustainability	2801 21st Ave S Ste 100 Minneapolis, MN 55407	Electronic Service	No	OFF_SL_13-867_Official
Todd J.	Guerrero	todd.guerrero@kutakrock.com	Kutak Rock LLP	Suite 1750 220 South Sixth Street Minneapolis, MN 554021425	Electronic Service	No	OFF_SL_13-867_Official
Timothy	Gulden	info@winonarenewableenergy.com	Winona Renewable Energy, LLC	1449 Ridgewood Dr Winona, MN 55987	Electronic Service	No	OFF_SL_13-867_Official
Duane	Hebert	duane.hebert@novelenergy.biz	Novel Energy Solutions	1628 2nd Ave SE Rochester, MN 55904	Electronic Service	No	OFF_SL_13-867_Official
Kimberly	Hellwig	kimberly.hellwig@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_13-867_Official
Jan	Hubbard	jan.hubbard@comcast.net		7730 Mississippi Lane Brooklyn Park, MN 55444	Electronic Service	No	OFF_SL_13-867_Official
John S.	Jaffray	jjaffray@jjrpower.com	JJR Power	350 Highway 7 Suite 236 Excelsior, MN 55331	Electronic Service	No	OFF_SL_13-867_Official
Linda	Jensen	linda.s.jensen@ag.state.mn.us	Office of the Attorney General-DOC	1800 BRM Tower 445 Minnesota Street St. Paul, MN 551012134	Electronic Service	No	OFF_SL_13-867_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Julie	Jorgensen	juliejorgensen@greenmarksolar.com	Greenmark Solar	4630 Quebec Ave N New Hope, MN 55428-4973	Electronic Service	No	OFF_SL_13-867_Official
Ralph	Kaehler	ralph.kaehler@novelenergy.biz		N/A	Electronic Service	No	OFF_SL_13-867_Official
Michael	Kampmeyer	mkampmeyer@a-e-group.com	AEG Group, LLC	260 Salem Church Road Sunfish Lake, Minnesota 55118	Electronic Service	No	OFF_SL_13-867_Official
Brad	Klein	bklein@elpc.org	Environmental Law & Policy Center	35 E. Wacker Drive, Suite 1600 Suite 1600 Chicago, IL 60601	Electronic Service	No	OFF_SL_13-867_Official
Aaron	Knoll	aknoll@greeneespel.com	Greene Espel PLLP	222 South Ninth Street Suite 2200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_13-867_Official
Jon	Kramer	sundialjon@gmail.com	Sundial Solar	3209 W 76th St Edina, MN 55435	Electronic Service	No	OFF_SL_13-867_Official
Michael	Krause	michaelkrause61@yahoo.com	Kandiyo Consulting, LLC	433 S 7th Street Suite 2025 Minneapolis, Minnesota 55415	Electronic Service	No	OFF_SL_13-867_Official
Dean	Leischow	dean@sunrisenrg.com	Sunrise Energy Ventures	315 Manitoba Ave Wayzata, MN 55391	Electronic Service	No	OFF_SL_13-867_Official
Thomas	Melone	Thomas.Melone@AllcoUS.com	Minnesota Go Solar LLC	222 South 9th Street Suite 1600 Minneapolis, Minnesota 55120	Electronic Service	No	OFF_SL_13-867_Official
Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP	33 South Sixth St Ste 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_13-867_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Rolf	Nordstrom	rnordstrom@gpisd.net	Great Plains Institute	2801 21ST AVE S STE 220 Minneapolis, MN 55407-1229	Electronic Service	No	OFF_SL_13-867_Official
Jeff	O'Neill	jeff.oneill@ci.monticello.mn.us	City of Monticello	505 Walnut Street Suite 1 Monticelllo, Minnesota 55362	Electronic Service	No	OFF_SL_13-867_Official
Eric	Pasi	ericp@ips-solar.com	IPS Solar	2670 Patton Rd Roseville, MN 55113	Electronic Service	No	OFF_SL_13-867_Official
Dan	Patry	dpatry@sunedison.com	SunEdison	600 Clipper Drive Belmont, CA 94002	Electronic Service	No	OFF_SL_13-867_Official
Jeffrey C	Paulson	jeff.jcplaw@comcast.net	Paulson Law Office, Ltd.	4445 W 77th Street Suite 224 Edina, MN 55435	Electronic Service	No	OFF_SL_13-867_Official
Joyce	Peppin	joyce@mrea.org	Minnesota Rural Electric Association	11640 73rd Ave N Maple Grove, MN 55369	Electronic Service	No	OFF_SL_13-867_Official
David	Shaffer	shaff081@gmail.com	Minnesota Solar Energy Industries Project	1005 Fairmount Ave Saint Paul, MN 55105	Electronic Service	No	OFF_SL_13-867_Official
Doug	Shoemaker	dougs@charter.net	Minnesota Renewable Energy	2928 5th Ave S Minneapolis, MN 55408	Electronic Service	No	OFF_SL_13-867_Official
Eric	Swanson	eswanson@winthrop.com	Winthrop & Weinstine	225 S 6th St Ste 3500 Capella Tower Minneapolis, MN 554024629	Electronic Service	No	OFF_SL_13-867_Official
Thomas P.	Sweeney III	tom.sweeney@easycleanenergy.com	Clean Energy Collective	P O Box 1828 Boulder, CO 80306-1828	Electronic Service	No	OFF_SL_13-867_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Lynnette	Sweet	Regulatory.records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	No	OFF_SL_13-867_Official
Anna	Tobin	atobin@greeneespel.com	Greene Espel PLLP	222 South Ninth Street Suite 2200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_13-867_Official
Pat	Treseler	pat.jcplaw@comcast.net	Paulson Law Office LTD	4445 W 77th Street Suite 224 Edina, MN 55435	Electronic Service	No	OFF_SL_13-867_Official
Daniel P	Wolf	dan.wolf@state.mn.us	Public Utilities Commission	121 7th Place East Suite 350 St. Paul, MN 551012147	Electronic Service	Yes	OFF_SL_13-867_Official

VOS Distribution Capacity Cost per kW

Year	New Dist. Capacity	Capital Cost - Capacity projects
	(MW)	($M)
2017	43.3	$10.270
2018	26.0	$7.812
2019	72.8	$5.862
2020	71.0	$15.380
2021	75.9	$16.000
Total	289.0	$55.324
Cost per kW		$191.43

Distibution Capacity Cost per kW	$191.43
Deferral Reduction Factor	50%
Avoided Distibution Capacity Cost per kW	$95.72

Minnesota Value of Solar: Methodology

Minnesota Department of Commerce,

Division of Energy Resources

APRIL 1, 2014*

*reformatted on April 9, 2014

Prepared by:

Clean Power Research

http://www.cleanpower.com/

Principal Investigators

Benjamin L. Norris
Morgan C. Putnam
Thomas E. Hoff

Prepared for:

Minnesota Department of Commerce,
Division of Energy Resources

Mike Rothman, Commissioner
Bill Grant, Deputy Commissioner
Matt Schuerger, Technical Advisor
Lise Trudeau, Project Manager
651-539-1861
lise.trudeau@state.mn.us

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Executive Summary

Minnesota passed legislation[1] in 2013 that allows Investor-Owned Utilities (IOUs) to apply to the Public Utility Commission (PUC) for a Value of Solar (VOS) tariff as an alternative to net metering, and as a rate identified for community solar gardens. The Department of Commerce (Commerce) was assigned the responsibility of developing and submitting a methodology for calculating the VOS tariff to the PUC by January 31, 2014. Utilities adopting the VOS will be required to follow this methodology when calculating the VOS tariff. Commerce selected Clean Power Research (CPR) to support the process of developing the methodology, and additionally held four public workshops to develop, present, and receive feedback.

The 2013 legislation specifically mandated that the VOS legislation take into account the following values of distributed PV: energy and its delivery; generation capacity; transmission capacity; transmission and distribution line losses; and environmental value. The legislation also mandated a method of implementation, whereby solar customers will be billed for their gross electricity consumption under their applicable tariff, and will receive a VOS credit for their gross solar electricity production.

The present document provides the methodology to be used by participating utilities. It is based on the enabling statute, stakeholder input, and guidance from Commerce. It includes a detailed example calculation for each step of the calculation.

Key aspects of the methodology include:

- A standard PV rating convention
- Methods for creating an hourly PV production time-series, representing the aggregate output of all PV systems in the service territory per unit capacity corresponding to the output of a PV resource on the margin
- Requirements for calculating the electricity losses of the transmission and distribution systems
- Methods for performing technical calculations for avoided energy, effective generation capacity and effective distribution capacity
- Economic methods for calculating each value component (e.g., avoided fuel cost, capacity cost, etc.)
- Requirements for summarizing input data and final calculations in order to facilitate PUC and stakeholder review

Application of the methodology results in the creation of two tables: the VOS Data Table (a table of utility-specific input assumptions) and the VOS Calculation Table (a table of utility-specific total value of

[1] MN Laws 2013, Chapter 85 HF 729, Article 9, Section 10.

solar). Together these two tables ensure transparency and facilitate understanding among stakeholders and regulators.

The VOS Calculation Table is illustrated in Figure ES-1. The table shows each value component and how the gross economic value of each component is converted into a distributed solar value. The process uses a component-specific load match factor (where applicable) and a component-specific loss savings factor. The values are then summed to yield the 25-year levelized value.

Figure ES-1. VOS Calculation Table: economic value, load match, loss savings and distributed PV value.

25 Year Levelized Value	Economic Value ($/kWh)	x	Load Match (No Losses) (%)	x	(1 +	Distributed Loss Savings (%)	)	=	Distributed PV Value ($/kWh)
Avoided Fuel Cost	E1					DLS-Energy			V1
Avoided Plant O&M - Fixed	E2		ELCC			DLS-ELCC			V2
Avoided Plant O&M - Variable	E3					DLS-Energy			V3
Avoided Gen Capacity Cost	E4		ELCC			DLS-ELCC			V4
Avoided Reserve Capacity Cost	E5		ELCC			DLS-ELCC			V5
Avoided Trans. Capacity Cost	E6		ELCC			DLS-ELCC			V6
Avoided Dist. Capacity Cost	E7		PLR			DLS-PLR			V7
Avoided Environmental Cost	E8					DLS-Energy			V8
Avoided Voltage Control Cost									
Solar Integration Cost									
									Lev. VOS

As a final step, the methodology calls for the conversion of the 25-year levelized value to an equivalent inflation-adjusted credit. The utility would then use the first year value as the credit for solar customers, and would adjust each year using the latest Consumer Price Index (CPI) data.

Contents

Introduction

Background

Minnesota passed legislation[2] in 2013 that allows Investor-Owned Utilities (IOUs) to apply to the Public Utility Commission (PUC) for a Value of Solar (VOS) tariff as an alternative to net metering, and as a rate identified for community solar gardens. The Department of Commerce (Commerce) was assigned the responsibility of developing and submitting a methodology for calculating the VOS tariff to the PUC by January 31, 2014. Utilities adopting the VOS will be required to follow this methodology when calculating the VOS rate. Commerce selected Clean Power Research (CPR) to support the process of developing the methodology, and additionally held four public workshops to develop, present, and receive feedback.

The present document provides the VOS methodology to be used by participating utilities. It is based on the enabling statute, stakeholder input and guidance from Commerce.

Purpose

The State of Minnesota has identified a VOS tariff as a potential replacement for the existing Net Energy Metering (NEM) policy that currently regulates the compensation of home and business owners for electricity production from PV systems. As such, the adopted VOS legislation is not an incentive for distributed PV, nor is it intended to eliminate or prevent current or future incentive programs.

While NEM effectively values PV-generated electricity at the customer retail rate, a VOS tariff seeks to quantify the value of distributed PV electricity. If the VOS is set correctly, it will account for the real value of the PV-generated electricity, and the utility and its ratepayers would be indifferent to whether the electricity is supplied from customer-owned PV or from comparable conventional means. Thus, a VOS tariff eliminates the NEM cross-subsidization concerns. Furthermore, a well-constructed VOS tariff could provide market signals for the adoption of technologies that significantly enhance the value of electricity from PV, such as advanced inverters that can assist the grid with voltage regulation.

VOS Calculation Table Overview

The VOS is the sum of several distinct value components, each calculated separately using procedures defined in this methodology. As illustrated in Figure 1, the calculation includes a gross component value, a component-dependent load-match factor (as applicable for capacity related values) and a component-dependent Loss Savings Factor.

[2] MN Laws 2013, Chapter 85 HF 729, Article 9, Section 10.

For example, the avoided fuel cost does not have a load match factor because it is not dependent upon performance at the highest hours (fuel costs are avoided during all PV operating hours). Avoided fuel cost does have a Loss Savings Factor, however, accounting for loss savings in both transmission and distribution systems. On the other hand, the Avoided Distribution Capacity Cost has an important Load Match Factor (shown as Peak Load Reduction, or 'PLR') and a Loss Savings Factor that only accounts for distribution (not transmission) loss savings.

Gross Values, Distributed PV Values, and the summed VOS shown in Figure 1 are all 25-year levelized values denominated in dollars per kWh.

Figure 1. Illustration of the VOS Calculation Table

25 Year Levelized Value	Economic Value ($/kWh)	x	Load Match (No Losses) (%)	x	(1 +	Distributed Loss Savings (%)	)	=	Distributed PV Value ($/kWh)
Avoided Fuel Cost	E1					DLS-Energy			V1
Avoided Plant O&M - Fixed	E2		ELCC			DLS-ELCC			V2
Avoided Plant O&M - Variable	E3					DLS-Energy			V3
Avoided Gen Capacity Cost	E4		ELCC			DLS-ELCC			V4
Avoided Reserve Capacity Cost	E5		ELCC			DLS-ELCC			V5
Avoided Trans. Capacity Cost	E6		ELCC			DLS-ELCC			V6
Avoided Dist. Capacity Cost	E7		PLR			DLS-PLR			V7
Avoided Environmental Cost	E8					DLS-Energy			V8
Avoided Voltage Control Cost									
Solar Integration Cost									
									Lev. VOS

VOS Rate Implementation

Separation of Usage and Production

Minnesota's VOS legislation mandates that, if a VOS tariff is approved, solar customers will be billed for all usage under their existing applicable tariff, and will receive a VOS credit for their gross solar energy production. Separating usage (charges) from production (credits) simplifies the rate process for several reasons:

- Customers will be billed for all usage. Energy derived from the PV systems will not be used to offset ("net") usage prior to calculating charges. This will ensure that utility infrastructure costs will be recovered by the utilities as designed in the applicable retail tariff.
- The utility will provide all energy consumed by the customer. Standby charges for customers with on-site PV systems are not permitted under a VOS rate.
- The rates for usage can be adjusted in future ratemaking.

VOS Components

The definition and selection of VOS components were based on the following considerations:

- Components corresponding to minimum statutory requirements are included. These account for the "value of energy and its delivery, generation capacity, transmission capacity, transmission and distribution line losses, and environmental value."
- Non-required components were selected only if they were based on known and measurable evidence of the cost or benefit of solar operation to the utility.
- Environmental costs are included as a required component, and are based on existing Minnesota and federal externality costs.
- Avoided fuel costs are based on long-term risk-free fuel supply contracts. This value implicitly includes both the avoided cost of fuel, as well as the avoided cost of price volatility risk that is otherwise passed from the utility to customers through fuel price adjustments.
- Credit for systems installed at high value locations (identified in the legislation as an option) is included as an option for the utility. It is not a separate VOS component but rather is implemented using a location-specific distribution capacity value (the component most affected by location). This is addressed in the Distribution Capacity Cost section.
- Voltage control and solar integration (a cost) are kept as "placeholder" components for future years. Methodologies are not provided, but these components may be developed for the future. Voltage control benefits are anticipated but will first require implementation of recent changes to national interconnection standards. Solar integration costs are expected to be small, but possibly measureable. Further research will be required on this topic.

Table 1 presents the VOS components selected by Commerce and the cost basis for each component. Table 2 presents the VOS components that were considered but not selected by Commerce. Selections were made based on requirements and guidance in the enabling statute, and were informed by stakeholder comments (including those from Minnesota utilities; local and national solar and environmental organizations; local solar manufacturers and installers; and private parties) and workshop discussions. Stakeholders participated in four public workshops and provided comments through workshop panels, workshop Q&A sessions and written comments.

Table 1. VOS components included in methodology.

Value Component	Basis	Legislative Guidance	Notes
Avoided Fuel Cost	Energy market costs (portion attributed to fuel)	Required (energy)	Includes cost of long-term price risk
Avoided Plant O&M Cost	Energy market costs (portion attributed to O&M)	Required (energy)	
Avoided Generation Capacity Cost	Capital cost of generation to meet peak load	Required (capacity)	
Avoided Reserve Capacity Cost	Capital cost of generation to meet planning margins and ensure reliability	Required (capacity)	
Avoided Transmission Capacity Cost	Capital cost of transmission	Required (transmission capacity)	
Avoided Distribution Capacity Cost	Capital cost of distribution	Required (delivery)	
Avoided Environmental Cost	Externality costs	Required (environmental)	
Voltage Control	Cost to regulate distribution (future inverter designs)		Future (TBD)
Integration Cost[3]	Added cost to regulate system frequency with variable solar		Future (TBD)

[3] This is not a value, but a cost. It would reduce the VOS rate if included.

Table 2. VOS components not included in methodology.

Value Component	Basis	Legislative Guidance	Notes
Credit for Local Manufacturing/ Assembly	Local tax revenue tied to net solar jobs	Optional (identified in legislation)	
Market Price Reduction	Cost of wholesale power reduced in response to reduction in demand		
Disaster Recovery	Cost to restore local economy (requires energy storage and islanding inverters)		

Solar Penetration

Solar penetration refers to the total installed capacity of PV on the grid, generally expressed as a percentage of the grid's total load. The level of solar penetration on the grid is important because it affects the calculation of the Effective Load Carrying Capability (ELCC) and Peak Load Reduction (PLR) load-match factors (described later).

In the methodology, the near-term level of PV penetration is used. This is done so that the capacity-related value components will reflect the near-term level of PV penetration on the grid. However, the change in PV penetration level will be accounted for in the annual adjustment to the VOS. To the extent that PV penetration increases, future VOS rates will reflect higher PV penetration levels.

Marginal Fuel

This methodology assumes that PV displaces natural gas during PV operating hours. This is consistent with current and projected MISO market experience. During some hours of the year, other fuels (such as coal) may be the fuel on the margin. In these cases, natural gas displacement is a simplifying assumption that is not expected to materially impact the calculated VOS tariff. However, if future analysis indicates that the assumption is not warranted, then the methodology may be modified accordingly. For example, by changing the methodology to include displacement of coal production, avoided fuel costs may decrease and avoided environmental costs may increase.

Economic Analysis Period

In evaluating the value of a distributed PV resource, the economic analysis period is set at 25 years, the assumed useful service life of the PV system[4]. The methodology includes PV degradation effects as described later.

Annual VOS Tariff Update

Each year, a new VOS tariff would be calculated using current data, and the new resulting VOS rate would be applicable to all customers entering the tariff during the year. Changes such as increased or decreased fuel prices and modified hourly utility load profiles due to higher solar penetration will be incorporated into each new annual calculation.

Customers who have already entered into the tariff in a previous year will not be affected by this annual adjustment. However, customers who have entered into a tariff in prior years will see their Value of Solar rates adjusted for the previous year's inflation rate as described later.

Commerce may also update the methodology to use the best available practices, as necessary.

Transparency Elements

The methodology incorporates two tables that are to be included in a utility's application to the Minnesota PUC for the use of a VOS tariff. These tables are designed to improve transparency and facilitate understanding among stakeholders and regulators.

- **VOS Data Table.** This table provides a utility-specific defined list of the key input assumptions that go into the VOS tariff calculation. This table is described in more detail later.
- **VOS Calculation Table.** This table includes the list of value components and their gross values, their load-match factors, their Loss Savings Factors, and the computation of the total levelized value.

Glossary

A glossary is provided at the end of this document defining some of the key terms used throughout this document.

[4] NREL: Solar Resource Analysis and High-Penetration PV Potential (April 2010). http://www.nrel.gov/docs/fy10osti/47956.pdf

Methodology: Assumptions

Fixed Assumptions

Table 3 and Table 4 present fixed assumptions, common to all utilities and incorporated into this methodology, that are to be applied to the calculation of 2014 VOS tariffs. These may be updated by Commerce in future years as necessary when performing the annual VOS update. Table 4 is described in more detail in the Avoided Environmental Cost subsection. Table terms can be found in the Glossary.

The general escalation rate is calculated as the average annual inflation rate over the last 25 years. The methodology uses the U.S. Bureau of Labor Statistics' Urban Consumer Price Index (CPI) data.

To retrieve Urban CPI data follow these steps:

1. Go to the U.S. Bureau of Labor Statistics's Top Picks for Consumer Price Index – All Urban Consumers[5]

2. Select " U.S. All items, 1982-84=100 - CUUR0000SA0". Click the "Retrieve Data" button near the bottom of the page.

3. Across from "Change Output Options", change the "from" and "to" years to capture the last 25 years of annual average CPI data. For example, a VOS rate calculated in 2014 would enter 1998 ("from" year) and 2013 ("to" year). Click on "go" to generate the data for this time period.

4. Select the annual average CPI numbers for the first and last year of the 25 year period. These numbers are under the "Annual" column. For example, the 1988 annual CPI factor is 118.3, and the 2013 factor is 232.957.

5. Use the annual CPI factors in equation (1) to calculate the 25 year average annual inflation rate.

$$25yrAvgAnnualInflation = \left(\frac{AnnualAvg_{year(-1)}\ UCPI}{AnnualAvg_{year(-26)}\ UCPI}\right)^{1/(25)} - 1 \qquad (1)$$

$$25yrAvgAnnualInflation = \left(\frac{AnnualAvg_{2013}\ UCPI}{AnnualAvg_{1998}\ UCPI}\right)^{1/(25)} - 1 = \left[\left(\frac{232.957}{118.300}\right)^{1/25} - 1\right] = 2.75\% \qquad (2)$$

[5] CPI data can currently be found at: http://data.bls.gov/cgi-bin/surveymost?cu

Table 3. Fixed assumptions used in Methodology's Example VOS calculations

Guaranteed NG Fuel Prices						
Year				**Environmental Externalities**		
2014	$3.93	$ per MMBtu		Environmental discount rate (nominal)	5.83%	per year
2015	$4.12	$ per MMBtu		Environmental costs	(shown in separate table)	
2016	$4.25	$ per MMBtu				
2017	$4.36	$ per MMBtu		**Economic Assumptions**		
2018	$4.50	$ per MMBtu		General escalation rate	2.75%	per year
2019	$4.73	$ per MMBtu				
2020	$5.01	$ per MMBtu				
2021	$5.33	$ per MMBtu		**Treasury Yields**		
2022	$5.67	$ per MMBtu		1 Year	0.13%	
2023	$6.02	$ per MMBtu		2 Year	0.29%	
2024	$6.39	$ per MMBtu		3 Year	0.48%	
2025	$6.77	$ per MMBtu		5 Year	1.01%	
				7 Year	1.53%	
PV Assumptions				10 Year	2.14%	
PV degradation rate	0.50%	per year		20 Year	2.92%	
PV life	25	years		30 Year	3.27%	

Table 4. Environmental externality costs by year.

Year	Analysis Year	CO_2 Cost ($/MMBtu)	PM10 Cost ($/MMBtu)	CO Cost ($/MMBtu)	NO_x Cost ($/MMBtu)	Pb Cost ($/MMBtu)	Total Cost ($/MMBtu)
2014	0	1.939	0.069	0.000	0.013	0.000	2.022
2015	1	2.046	0.071	0.000	0.013	0.000	2.131
2016	2	2.158	0.073	0.000	0.014	0.000	2.245
2017	3	2.274	0.075	0.000	0.014	0.000	2.363
2018	4	2.395	0.077	0.000	0.015	0.000	2.487
2019	5	2.521	0.079	0.000	0.015	0.000	2.615
2020	6	2.652	0.082	0.000	0.015	0.000	2.749
2021	7	2.788	0.084	0.000	0.016	0.000	2.888
2022	8	2.930	0.086	0.000	0.016	0.000	3.032
2023	9	3.077	0.089	0.000	0.017	0.000	3.182
2024	10	3.230	0.091	0.000	0.017	0.000	3.338
2025	11	3.390	0.093	0.000	0.018	0.000	3.501
2026	12	3.555	0.096	0.000	0.018	0.000	3.669
2027	13	3.653	0.099	0.000	0.019	0.000	3.770
2028	14	3.830	0.101	0.000	0.019	0.000	3.950
2029	15	4.014	0.104	0.000	0.020	0.000	4.138
2030	16	4.205	0.107	0.000	0.020	0.000	4.332
2031	17	4.404	0.110	0.000	0.021	0.000	4.534
2032	18	4.610	0.113	0.000	0.021	0.000	4.744
2033	19	4.824	0.116	0.000	0.022	0.000	4.962
2034	20	5.047	0.119	0.000	0.023	0.000	5.189
2035	21	5.278	0.123	0.000	0.023	0.000	5.424
2036	22	5.518	0.126	0.000	0.024	0.000	5.668
2037	23	5.768	0.129	0.000	0.024	0.000	5.922
2038	24	6.027	0.133	0.000	0.025	0.000	6.185

See explanation in the Avoided Environmental Cost section.

Utility-Specific Assumptions and Calculations

Some assumptions and calculations are unique to each utility. These include economic assumptions (such as discount rate) and technical calculations (such as ELCC). Utility-specific assumptions and calculations are determined by the utility, and are included in the VOS Data Table, a required transparency element.

The utility-specific calculations (such as capacity-related transmission capital cost) are determined using the methods described in this methodology.

An example VOS Data Table, showing the parameters to be included in the utility filing for the VOS tariff, is shown in Table 5. This table includes values that are given for example only. These example values carry forward in the example calculations.

Table 5. VOS Data Table (EXAMPLE DATA) — required format showing example parameters used in the example calculations.

	Input Data	Units
Economic Factors		
Start Year for VOS applicability	2014	
Discount rate (WACC)	8.00%	per year
Load Match Analysis (see calculation method)		
ELCC (no loss)	40%	% of rating
PLR (no loss)	30%	% of rating
Loss Savings – Energy	8%	% of PV output
Loss Savings – PLR	5%	% of PV output
Loss Savings – ELCC	9%	% of PV output
PV Energy (see calculation method)		
First year annual energy	1800	kWh per kW-AC
Transmission (see calculation method)		
Capacity-related transmission capital cost	$33	$ per kW-yr

	Input Data	Units
Power Generation		
Peaking CT, simple cycle		
Installed cost	900	$/kW
Heat rate	9,500	BTU/kWh
Intermediate peaking CCGT		
Installed cost	1,200	$/kW
Heat rate	6,500	BTU/kWh
Other		
Solar-weighted heat rate (see calc. method)	8000	BTU per kWh
Fuel Price Overhead	$0.50	$ per MMBtu
Generation life	50	years
Heat rate degradation	0.100%	per year
O&M cost (first Year) - Fixed	$5.00	per kW-yr
O&M cost (first Year) - Variable	$0.0010	$ per kWh
O&M cost escalation rate	2.00%	per year
Reserve planning margin	15%	
Distribution		
Capacity-related distribution capital cost	$200	$ per kW
Distribution capital cost escalation	2.00%	per year
Peak load	5000	MW
Peak load growth rate	1.00%	per year

Methodology: Technical Analysis

Load Analysis Period

The VOS methodology requires that a number of technical parameters (PV energy production, effective load carrying capability (ELCC) and peak load reduction (PLR) load-match factors, and electricity-loss factors) be calculated over a fixed period of time in order to account for day-to-day variations and seasonal effects, such as changes in solar radiation. For this reason, the load analysis period must cover a period of at least one year.

The data may start on any day of the year, and multiple years may be included, as long as all included years are contiguous and each included year is a complete one-year period. For example, valid load analysis periods may be 1/1/2012 0:00 to 12/31/2012 23:00 or 11/1/2010 0:00 to 10/31/2013 23:00.

Three types of time series data are required to perform the technical analysis:

- **Hourly Generation Load:** the hourly utility load over the Load Analysis Period. This is the sum of utility generation and import power needed to meet all customer load.
- **Hourly Distribution Load:** the hourly distribution load over the Load Analysis Period. The distribution load is the power entering the distribution system from the transmission system (i.e., generation load minus transmission losses).
- **Hourly PV Fleet Production:** the hourly PV Fleet production over the Load Analysis Period. The PV fleet production is the aggregate generation of all of the PV systems in the PV fleet.

All three types of data must be provided as synchronized, time-stamped hourly values of average power over the same period, and corresponding to the same hourly intervals. Data must be available for every hour of the Load Analysis Period.

PV data using Typical Meteorological Year data is not time synchronized with time series production data, so it should not be used as the basis for PV production.

Data that is not in one-hour intervals must be converted to hourly data (for example, 15-minute meter data would have to be combined to obtain 1-hour data). Also, data values that represent energy must be converted to average power.

If data is missing or deemed erroneous for any time period less than or equal to 24 hours, the values corresponding to that period may be replaced with an equal number of values from the same time interval on the previous or next day if it contains valid data. This data replacement method may be used provided that it does not materially affect the results.

PV Energy Production

PV System Rating Convention

The methodology uses a rating convention for PV capacity based on AC delivered energy (not DC), taking into account losses internal to the PV system. A PV system rated output is calculated by multiplying the number of modules by the module PTC rating[6] [as listed by the California Energy Commission (CEC)[7]] to account for module de-rate effects. The result is then multiplied by the CEC-listed inverter efficiency rating[8] to account for inverter efficiency, and the result is multiplied by a loss factor to account for internal PV array losses (wiring losses, module mismatch and other losses).

If no CEC module PTC rating is available, the module PTC rating should be calculated as 0.90 times the module STC rating[9]. If no CEC inverter efficiency rating is available, an inverter efficiency of 0.95 should be used. If no measured or design loss factor is available, 0.85 should be used.

To summarize: [10]

Rating (kW-AC) = [Module Quantity] x [Module PTC rating (kW)] x [Inverter Efficiency Rating] x [Loss Factor]

Hourly PV Fleet Production

Hourly PV Fleet Production can be obtained using any one of the following three options:

1. Utility Fleet - Metered Production. Fleet production data can be created by combining actual metered production data for every PV system in the utility service territory, provided that there are a sufficient number of systems[11] installed to accurately derive a correct representation of aggregate PV production. Such metered data is to be gross PV output on the AC side of the

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[6] PTC refers to PVUSA Test Conditions, which were developed to test and compare PV systems as part of the PVUSA (Photovoltaics for Utility Scale Applications) project. PTC are 1,000 Watts per square meter solar irradiance, 20 degrees C air temperature, and wind speed of 1 meter per second at 10 meters above ground level. PV manufacturers use Standard Test Conditions, or STC, to rate their PV products.
[7] CEC module PTC ratings for most modules can be found at: http://www.gosolarcalifornia.ca.gov/equipment/pv_modules.php
[8] CEC inverter efficiency ratings for most inverters can be found at: http://www.gosolarcalifornia.ca.gov/equipment/inverters.php
[9] PV manufacturers use Standard Test Conditions, or STC, to rate their PV products. STC are 1,000 Watts per square meter solar irradiance, 25 degrees C cell temperature, air mass equal to 1.5, and ASTM G173-03 standard spectrum.
[10] In some cases, this equation will have to be adapted to account for multiple module types and/or inverters. In such cases, the rating of each subsystem can be calculated independently and then added.
[11] A sufficient number of systems has been achieved when adding a single system of random orientation, tilt, tracking characteristics, and capacity (within reason) does not materially change the observed hourly PV Fleet Shape (see next subsection of PV Fleet Shape definition).

system, but before local customer loads are subtracted (i.e., PV must be separately metered from load). Metered data from individual systems is then aggregated by summing the measured output for all systems for each one-hour period. For example, if system A has an average power of 4.5 kW-AC from 11:00 AM to 12:00 PM, and system B has an average power of 2.3 kW-AC from 11:00 AM to 12:00 PM, the combined average power for 11:00 AM to 12:00 PM would be 6.8 kW-AC.

2. Utility Fleet, Simulated Production. If metered data is not available, the aggregate output of all distributed PV systems in the utility service territory can be modeled using PV system technical specifications and hourly irradiance and temperature data. These systems must be deployed in sufficient numbers to accurately derive a correct representation of aggregate PV production. Modeling must take into account the system's location and each array's tracking capability (fixed, single-axis or dual-axis tracking), orientation (tilt and azimuth), module PTC ratings, inverter efficiency and power ratings, other loss factors and the effect of temperature on module output. Technical specifications for each system must be available to enable such modeling. Modeling must also make use of location-specific, time-correlated, measured or satellite-derived plane of array irradiance data. Ideally, the software will also support modeling of solar obstructions.

   - To make use of this option, detailed system specifications for every PV system in the utility's service territory must be obtained. At a minimum, system specifications must include:
     - Location (latitude and longitude)
     - System component ratings (e.g., module ratings an inverter ratings)
     - Tilt and azimuth angles
     - Tracking type (if applicable)
   - After simulating the power production for each system for each hour in the Load Analysis Period, power production must be aggregated by summing the power values for all systems for each one-hour period. For example, if system A has an average power of 4.5 kW-AC from 11:00 AM to 12:00 PM, and system B has an average power of 2.3 kW-AC from 11:00 AM to 12:00 PM, the combined average power for 11:00 AM to 12:00 PM would be 6.8 kW-AC.

3. Expected Fleet, Simulated Production. If neither metered production data nor detailed PV system specifications are available, a diverse set of PV resources can be estimated by simulating groups of systems at major load centers in the utility's service territory with some assumed fleet configuration. To use this method, one or more of the largest load centers in the utility service territory may be used. If a single load center accounts for a high percentage of the utility's total load, a single location will suffice. If there are several large load centers in the territory, groups of systems can be created at each location with capacities proportional to the load in that area.

   - For each location, simulate multiple systems, each rated in proportion to the expected capacity, with azimuth and tilt angles such as the list of systems presented in Table 6. Note that the list of system configurations should represent the expected fleet composition. No method is explicitly provided to determine the expected fleet composition; however, a utility could analyze the fleet composition of PV fleets outside of its territory.

Table 6. (EXAMPLE) Azimuth and tilt angles

System	Azimuth	Tilt	% Capacity
1	90	20	3.5
2	135	15	3.0
3	135	30	6.5
4	180	0	6.0
5	180	15	16.0
6	180	25	22.5
7	180	35	18.0
8	235	15	8.5
9	235	30	9.0
10	270	20	7.0

- Simulate each of the PV systems for each hour in the Load Analysis Period. Aggregate power production for the systems is obtained by summing the power values for each one-hour period. For example, if system A has an average power of 4.5 kW-AC from 11:00 AM to 12:00 PM, and system B has an average power of 2.3 kW-AC from 11:00 AM to 12:00 PM, the combined average power for 11:00 AM to 12:00 PM would be 6.8 kW-AC.
- If the utility elects to perform a location-specific analysis for the Avoided Distribution Capacity Costs, then it should also take into account what the geographical distribution of the expected PV fleet would be. Again, this could be done by analyzing a PV fleet composition outside of the utility's territory. An alternative method that would be acceptable is to distribute the expected PV fleet across major load centers. Thereby assuming that PV capacity is likely to be added where significant load (and customer density) already exists.
- Regardless of location count and location weighting, the total fleet rating is taken as the sum of the individual system ratings.

PV Fleet Shape

Regardless of which of the three methods is selected for obtaining the Hourly PV Fleet production, the next step is divide each hour's value by the PV Fleet's aggregate AC rating to obtain the PV Fleet Shape. The units of the PV Fleet Shape are kWh per hour per kW-AC (or, equivalently, average kW per kW-AC).

Marginal PV Resource

The PV Fleet Shape is hourly production of a Marginal PV Resource having a rating of 1 kW-AC.

Annual Avoided Energy

Annual Avoided Energy (kWh per kW-AC per year) is the sum of the hourly PV Fleet Shape across all hours of the Load Analysis Period, divided by the numbers of years in the Load Analysis Period. The result is the annual output of the Marginal PV Resource.

$$Annual\ Avoided\ Energy\ (kWh) = \frac{\sum Hourly\ PV\ Fleet\ Production_h}{NumberOfYearsInLoadAnalysisPeriod} \qquad (3)$$

- Defined in this way, the Annual Avoided Energy does not include the effects of loss savings. As described in the Loss Analysis subsection, however, it will have to be calculated for the two loss cases (with losses and without losses).

Load-Match Factors

Capacity-related benefits are time dependent, so it is necessary to evaluate the effectiveness of PV in supporting loads during the critical peak hours. Two different measures of effective capacity are used:

- Effective Load Carrying Capability (ELCC)
- Peak Load Reduction (PLR)

Near term PV penetration levels are used in the calculation of the ELCC and PLR values so that the capacity-related value components will reflect the near term level of PV penetration on the grid. However, the ELCC and PLR will be re-calculated during the annual VOS adjustment and thus reflect any increase in future PV Penetration Levels.

Effective Load Carrying Capability (ELCC)

The Effective Load Carrying Capability (ELCC) is the measure of the effective capacity for distributed PV that can be applied to the avoided generation capacity costs, the avoided reserve capacity costs, the avoided generation fixed O&M costs, and the avoided transmission capacity costs (see Figure 1).

Using current MISO rules for non-wind variable generation (MISO BPM-011, Section 4.2.2.4, page 35)[12]: the ELCC will be calculated from the PV Fleet Shape for hours ending 2pm, 3pm, and 4pm Central Standard Time during June, July, and August over the most recent three years. If three years of data are unavailable, MISO requires “a minimum of 30 consecutive days of historical data during June, July, or August” for the hours ending 2pm, 3pm and 4pm Central Standard Time.

The ELCC is calculated by averaging the PV Fleet Shape over the specified hours, and then dividing by the rating of the Marginal PV Resource (1 kW-AC), which results in a percentage value. Additionally, the ELCC must be calculated for the two loss cases (with and without T&D losses, as described in the Loss Analysis subsection).

Peak Load Reduction (PLR)

The PLR is defined as the maximum distribution load over the Load Analysis Period (without the Marginal PV Resource) minus the maximum distribution load over the Load Analysis Period (with the Marginal PV Resource). The distribution load is the power entering the distribution system from the transmission system (i.e., generation load minus transmission losses). In calculating the PLR, it is not sufficient to limit modeling to the peak hour. All hours over the Load Analysis Period must be included in the calculation. This is because the reduced peak load may not occur in the same hour as the original peak load.

The PLR is calculated as follows. First, determine the maximum Hourly Distribution Load (D1) over the Load Analysis Period. Next, create a second hourly distribution load time series by subtracting the effect of the Marginal PV Resource, i.e., by evaluating what the new distribution load would be each hour given the PV Fleet Shape. Next, determine the maximum load in the second time series (D2). Finally, calculate the PLR by subtracting D2 from D1.

In other words, the PLR represents the capability of the Marginal PV Resource to reduce the peak distribution load over the Load Analysis Period. PLR is expressed in kW per kW-AC.

Additionally, the PLR must be calculated for the two loss cases (with distribution losses and without distribution losses, as described in the Loss Analysis subsection).

[12] https://www.misoenergy.org/Library/BusinessPracticesManuals/Pages/BusinessPracticesManuals.aspx

Loss Savings Analysis

In order to calculate the required Loss Savings Factors on a marginal basis as described below, it will be necessary to calculate ELCC, PLR and Annual Avoided Energy each twice. They should be calculated first by *including* the effects of avoided marginal losses, and second by *excluding* them. For example, the ELCC would first be calculated by including avoided transmission and distribution losses, and then re-calculated assuming no losses, i.e., as if the Marginal PV Resource was a central (not distributed) resource.

The calculations should observe the following

Table 7. Losses to be considered.

Technical Parameter	Loss Savings Considered
Avoided Annual Energy	Avoided transmission and distribution losses for every hour of the load analysis period.
ELCC	Avoided transmission and distribution losses during the MISO defined hours.
PLR	Avoided distribution losses (not transmission) at peak.

When calculating avoided marginal losses, the analysis must satisfy the following requirements:

1. Avoided losses are to be calculated on an hourly basis over the Load Analysis Period. The avoided losses are to be calculated based on the generation (and import) power during the hour and the expected output of the Marginal PV Resource during the hour.

2. Avoided losses in the transmission system and distribution systems are to be evaluated separately using distinct loss factors based on the most recent study data available.

3. Avoided losses should be calculated on a marginal basis. The marginal avoided losses are the difference in hourly losses between the case without the Marginal PV Resource, and the case with the Marginal PV Resource. Avoided average hourly losses are not calculated. For example, if the Marginal PV Resource were to produce 1 kW of power for an hour in which total customer load is 1000 kW, then the avoided losses would be the calculated losses at 1000 kW of customer load minus the calculated losses at 999 kW of load.

4. Distribution losses should be based on the power entering the distribution system, after transmission losses.

5. Avoided transmission losses should take into account not only the marginal PV generation, but also the avoided marginal distribution losses.

6. Calculations of avoided losses should not include no-load losses (e.g., corona, leakage current). Only load-related losses should be included.

7. Calculations of avoided losses in any hour should take into account the non-linear relationship between losses and load (load-related losses are proportional to the square of the load, assuming constant voltage). For example, the total load-related losses during an hour with a load of 2X would be approximately 4 times the total load-related losses during an hour with a load of only X.

Loss Savings Factors

The Energy Loss Savings Factor (as a percentage) is defined for use within the VOS Calculation Table:

$$Annual\ Avoided\ Energy_{WithLosses} = Annual\ Avoided\ Energy_{WithoutLosses}\left(1 + Loss\ Savings_{Energy}\right) \quad (4)$$

Equation 5 is then rearranged to solve for the Energy Loss Savings Factor:

$$Loss\ Savings_{Energy} = \frac{Annual\ Avoided\ Energy_{WithLosses}}{Annual\ Avoided\ Energy_{WithoutLosses}} - 1 \quad (5)$$

Similarly, the PLR Loss Savings Factor is defined as:

$$Loss\ Savings_{PLR} = \frac{PLR_{WithLosses}}{PLR_{WithoutLosses}} - 1 \quad (6)$$

and the ELCC Loss Savings Factor is defined as:

$$Loss\ Savings_{ELCC} = \frac{ELCC_{WithLosses}}{ELCC_{WithoutLosses}} - 1 \quad (7)$$

Methodology: Economic Analysis

The following subsections provide a methodology for performing the economic calculations to derive gross values in $/kWh for each of the VOS components. These gross component values will then be entered into the VOS Calculation Table, which is the second of the two key transparency elements.

Important Note: The economic analysis is initially performed as if PV was centrally-located (without loss-saving benefits of distributed location) and with output perfectly correlated to load. Real-world adjustments are made later in the final VOS summation by including the results of the loss savings and load match analyses.

Discount Factors

By convention, the analysis year 0 corresponds to the year in which the VOS tariff will begin. As an example, if a VOS was done in 2013 for customers entering a VOS tariff between January 1, 2014 and December 31, 2014, then year 0 would be 2014, year 1 would be 2015, and so on.

For each year *i*, a discount factor is given by

$$DiscountFactor_i = \frac{1}{(1 + DiscountRate)^i} \quad (8)$$

The *DiscountRate* is the utility Weighted Average Cost of Capital.

Similarly, a risk-free discount factor is given by:

$$RiskFreeDiscountFactor_i = \frac{1}{(1 + RiskFreeDiscountRate)^i} \quad (9)$$

The *RiskFreeDiscountRate* is based on the yields of current Treasury securities[13] of 1, 2, 3, 5, 7, 10, 20, and 30 year maturation dates. The *RiskFreeDiscountRate* is used once in the calculation of the Avoided Fuel Costs.

Finally, an environmental discount factor is given by:

$$EnvironmentalDiscountFactor_i = \frac{1}{(1 + EnvironmentalDiscountRate)^i} \quad (10)$$

[13] See http://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?data=yield

The *EnvironmentalDiscountRate* is based on the 3% *real* discount rate that has been determined to be an appropriate societal discount rate for future environmental benefits.[14] As the methodology requires a nominal discount rate, this 3% *real* discount rate is converted into its equivalent 5.61% nominal discount rate as follows:[15]

$$NominalDiscountRate = (1 + RealDiscountRate) \times (1 + GeneralEscalationRate) - 1 \tag{11}$$

The *EnvironmentalDiscountRate* is used once in the calculation of the Avoided Environmental Costs.

PV degradation is accounted for in the economic calculations by reductions of the annual PV production in future years. As such, the PV production in kWh per kW-AC for the marginal PV resource in year I is given by:

$$PVProduction_i = PVProduction_0 \times (1 - \mathrm{PVDegradationRate})^i \tag{12}$$

where PVDegradationRate is the annual rate of PV degradation, assumed to be 0.5% per year – the standard PV module warranty guarantees a maximum of 0.5% power degradation per annum. $PVProduction_0$ is the Annual Avoided Energy for the Marginal PV Resource.

PV capacity in year *i* for the Marginal PV Resource, taking into account degradation, equals:

$$PVCapacity_i = (1 - \mathrm{PVDegradationRate})^i \tag{13}$$

Avoided Fuel Cost

Avoided fuel costs are based on long-term, risk-free fuel supply contracts. This value implicitly includes both the avoided cost of fuel as well as the avoided cost of price volatility risk that is otherwise passed from the utility to customers through fuel price adjustments.

PV displaces energy generated from the marginal unit, so it avoids the cost of fuel associated with this generation. Furthermore, the PV system is assumed to have a service life of 25 years, so the uncertainty in fuel price fluctuations is also eliminated over this period. For this reason, the avoided fuel cost must take into account the fuel as if it were purchased under a guaranteed, long term contract.

[14] http://www.epa.gov/oms/climate/regulations/scc-tsd.pdf
[15] http://en.wikipedia.org/wiki/Nominal_interest_rate

The methodology provides for three options to accomplish this:

- **Futures Market.** This option is described in detail below, and is based on the NYMEX NG futures with a fixed escalation for years beyond the 12-year trading period.
- **Long Term Price Quotation.** This option is identical to the above option, except the input pricing data is based on an actual price quotation from an AA-rated NG supplier to lock in prices for the 25-year guaranteed period.
- **Utility-guaranteed Price.** This is the 25-year fuel price that is guaranteed by the utilities. Tariffs using the utility guaranteed price will include a mechanism for removing the usage fuel adjustment charges and provide fixed prices over the term.

Table 8 presents the calculation of the economic value of avoided fuel costs.

For the Futures Market option, Guaranteed NG prices are calculated as follows. Prices for the first 12 years are based on NYMEX natural gas futures quotes. These quotes are published daily by the CME Group.[16]

Guaranteed NG prices are calculated by following these steps:

1. First, monthly prices are determined by averaging the 30 days of NYMEX prices for each month, starting with the most recent 30 daily prices and then repeating the same 30-day averaging for every other contract month of the 12 year period. If a utility calculating a VOS rate does not have historical daily NYMEX prices already collected internally they can obtain this data by recording quotes for 30 days. The timing of the data collection should be accounted for in planning the VOS rate calculation.

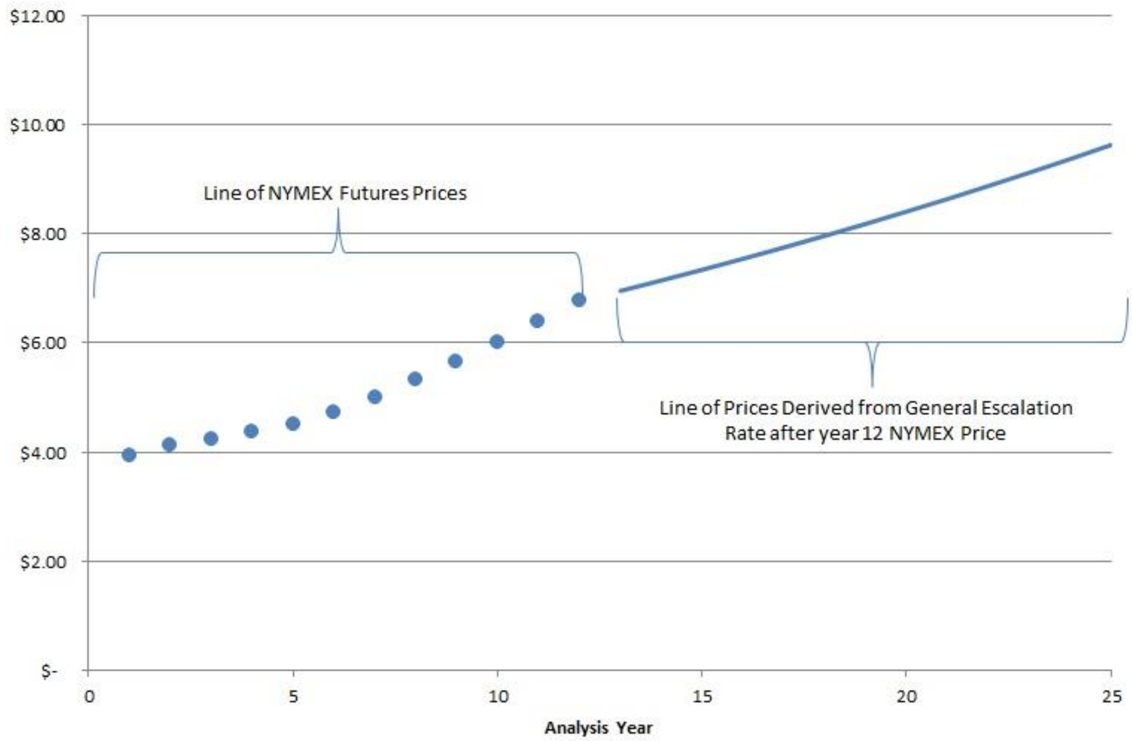
2. Then, the monthly prices are averaged to give a 12-month average in $ per MMBtu, resulting in the first 12 annual prices in the set of 25 annual prices. Prices for years beyond this NYMEX limit are calculated by applying the general escalation rate. An assumed fuel price overhead amount, escalated by year using the general escalation rate, is added to the fuel price to give the burnertip fuel price.

3. Prices for years 13 through 25 are calculated by escalating the year 12 annual average NYMEX quote by the general escalation rate annually for each year.

The guaranteed fuel prices for the methodology's example calculation are shown in figure 2 below.

[16] CME Group's Natural Gas (Henry Hub) Physical Futures Quotes can be found at: http://www.cmegroup.com/trading/energy/natural-gas/natural-gas.html.

Figure 2. (EXAMPLE) Guaranteed Fuel Prices



The first-year solar-weighted heat rate is calculated as follows:

$$SolarWeighedHeatRate_0 = \frac{\sum HeatRate_j \times FleetProduction_j}{\sum FleetProduction_j} \quad (14)$$

where the summation is over all hours *j* of the load analysis period, *HeatRate* is the actual heat rate of the plant on the margin, and *FleetProduction* is the Fleet Production Shape time series.

The solar-weighted heat rate for future years is calculated as:

$$SolarWeighedHeatRate_i = SolarWeighedHeatRate_0 \times (1 + \text{HeatRateDegradationRate})^i \quad (15)$$

The utility price in year *i* is:

$$UtilityPrice_i = \frac{BurnertipFuelPrice_i \times SolarWeighedHeatRate_i}{10^6} \quad (16)$$

where the burnertip price is in $ per MMBtu and the heat rate is in Btu per kWh.

Utility cost is the product of the utility price and the per unit PV production. These costs are then discounted using the risk free discount rate and summed for all years. A risk-free discount rate (fitted to the US Treasury yields shown in Table 3) has been selected to account for the fact that there is no risk in the avoided fuel cost.

The VOS price (shown in red in Table 8) is the levelized amount that results in the same discounted amount as the utility price for the Avoided Fuel Cost component.

Table 8. (EXAMPLE) Economic Value of Avoided Fuel Costs.

Year	Guaranteed NG Price ($/MMBtu)	Burnertip NG Price ($/MMBtu)	Heat Rate (Btu/kWh)	Prices Utility ($/kWh)	Prices VOS ($/kWh)	p.u. PV Production (kWh)	Costs Utility ($)	Costs VOS ($)	Discount Factor (risk free)	Disc. Costs Utility ($)	Disc. Costs VOS ($)
2014	$3.93	$4.43	8000	$0.035	$0.056	1,800	$64	$101	1.000	$64	$101
2015	$4.12	$4.64	8008	$0.037	$0.056	1,791	$67	$100	0.999	$66	$100
2016	$4.25	$4.77	8016	$0.038	$0.056	1,782	$68	$100	0.994	$68	$99
2017	$4.36	$4.90	8024	$0.039	$0.056	1,773	$70	$99	0.986	$69	$98
2018	$4.50	$5.05	8032	$0.041	$0.056	1,764	$72	$99	0.971	$70	$96
2019	$4.73	$5.30	8040	$0.043	$0.056	1,755	$75	$98	0.951	$71	$94
2020	$5.01	$5.60	8048	$0.045	$0.056	1,747	$79	$98	0.927	$73	$91
2021	$5.33	$5.94	8056	$0.048	$0.056	1,738	$83	$97	0.899	$75	$88
2022	$5.67	$6.29	8064	$0.051	$0.056	1,729	$88	$97	0.872	$76	$85
2023	$6.02	$6.66	8072	$0.054	$0.056	1,721	$92	$96	0.842	$78	$81
2024	$6.39	$7.04	8080	$0.057	$0.056	1,712	$97	$96	0.809	$79	$78
2025	$6.77	$7.44	8088	$0.060	$0.056	1,703	$103	$96	0.786	$81	$75
2026	$6.95	$7.64	8097	$0.062	$0.056	1,695	$105	$95	0.762	$80	$72
2027	$7.14	$7.86	8105	$0.064	$0.056	1,686	$107	$95	0.737	$79	$70
2028	$7.34	$8.07	8113	$0.065	$0.056	1,678	$110	$94	0.713	$78	$67
2029	$7.54	$8.29	8121	$0.067	$0.056	1,670	$112	$94	0.688	$77	$64
2030	$7.75	$8.52	8129	$0.069	$0.056	1,661	$115	$93	0.663	$76	$62
2031	$7.96	$8.76	8137	$0.071	$0.056	1,653	$118	$93	0.637	$75	$59
2032	$8.18	$9.00	8145	$0.073	$0.056	1,645	$121	$92	0.612	$74	$56
2033	$8.41	$9.24	8153	$0.075	$0.056	1,636	$123	$92	0.587	$72	$54
2034	$8.64	$9.50	8162	$0.078	$0.056	1,628	$126	$91	0.563	$71	$51
2035	$8.88	$9.76	8170	$0.080	$0.056	1,620	$129	$91	0.543	$70	$49
2036	$9.12	$10.03	8178	$0.082	$0.056	1,612	$132	$90	0.523	$69	$47
2037	$9.37	$10.30	8186	$0.084	$0.056	1,604	$135	$90	0.504	$68	$45
2038	$9.63	$10.59	8194	$0.087	$0.056	1,596	$138	$89	0.485	$67	$43
							Validation: Present Value			**$1,826**	**$1,826**

Avoided Plant O&M – Fixed

Economic value calculations for fixed plant O&M are presented in Table 9. The first year fixed value is escalated at the O&M escalation rate for future years.

Similarly, PV capacity has an initial value of one during the first year because it is applicable to PV systems installed in the first year. Note that effective capacity (load matching) is handled separately, and this table represents the "ideal" resource, as if PV were able to receive the same capacity credit as a fully dispatchable technology.

The utility cost is the fixed O&M cost times the PV capacity divided by the utility capacity. Utility prices are the cost divided by the PV production. Costs are discounted using the utility discount factor and are summed for all years.

The VOS component value is calculated as before such that the discounted total is equal to the discounted utility cost.

Table 9. (EXAMPLE) Economic value of avoided plant O&M – fixed

				Prices			Costs			Disc. Costs	
Year	O&M Fixed	Utility Capacity	PV Capacity	Utility	VOS	p.u. PV Production	Utility	VOS	Discount Factor	Utility	VOS
	($/kW)	(p.u.)	(kW)	($/kWh)	($/kWh)	(kWh)	($)	($)		($)	($)
2014	$5.00	1.000	1.000	$0.003	$0.003	1800	$5	$6	1.000	$5	$6
2015	$5.11	0.999	0.995	$0.003	$0.003	1791	$5	$6	0.926	$5	$6
2016	$5.21	0.998	0.990	$0.003	$0.003	1782	$5	$6	0.857	$4	$5
2017	$5.32	0.997	0.985	$0.003	$0.003	1773	$5	$6	0.794	$4	$5
2018	$5.43	0.996	0.980	$0.003	$0.003	1764	$5	$6	0.735	$4	$4
2019	$5.55	0.995	0.975	$0.003	$0.003	1755	$5	$6	0.681	$4	$4
2020	$5.66	0.994	0.970	$0.003	$0.003	1747	$6	$6	0.630	$3	$4
2021	$5.78	0.993	0.966	$0.003	$0.003	1738	$6	$6	0.583	$3	$3
2022	$5.91	0.992	0.961	$0.003	$0.003	1729	$6	$6	0.540	$3	$3
2023	$6.03	0.991	0.956	$0.003	$0.003	1721	$6	$6	0.500	$3	$3
2024	$6.16	0.990	0.951	$0.003	$0.003	1712	$6	$6	0.463	$3	$3
2025	$6.29	0.989	0.946	$0.004	$0.003	1703	$6	$6	0.429	$3	$2
2026	$6.42	0.988	0.942	$0.004	$0.003	1695	$6	$6	0.397	$2	$2
2027	$6.55	0.987	0.937	$0.004	$0.003	1686	$6	$6	0.368	$2	$2
2028	$6.69	0.986	0.932	$0.004	$0.003	1678	$6	$6	0.340	$2	$2
2029	$6.83	0.985	0.928	$0.004	$0.003	1670	$6	$6	0.315	$2	$2
2030	$6.97	0.984	0.923	$0.004	$0.003	1661	$7	$6	0.292	$2	$2
2031	$7.12	0.983	0.918	$0.004	$0.003	1653	$7	$6	0.270	$2	$1
2032	$7.27	0.982	0.914	$0.004	$0.003	1645	$7	$5	0.250	$2	$1
2033	$7.42	0.981	0.909	$0.004	$0.003	1636	$7	$5	0.232	$2	$1
2034	$7.58	0.980	0.905	$0.004	$0.003	1628	$7	$5	0.215	$2	$1
2035	$7.74	0.979	0.900	$0.004	$0.003	1620	$7	$5	0.199	$1	$1
2036	$7.90	0.978	0.896	$0.004	$0.003	1612	$7	$5	0.184	$1	$1
2037	$8.07	0.977	0.891	$0.005	$0.003	1604	$7	$5	0.170	$1	$1
2038	$8.24	0.976	0.887	$0.005	$0.003	1596	$7	$5	0.158	$1	$1
							Validation: Present Value			**$67**	**$67**

Avoided Plant O&M – Variable

An example calculation of avoided plant O&M is displayed in Table 10. Utility prices are given in the VOS Data Table, escalated each year by the O&M escalation rate. As before, the per unit PV production is shown with annual degradation taken into account. The utility cost is the product of the utility price and the per unit production, and these costs are discounted. The VOS price of variable O&M is the levelized value resulting in the same total discounted cost.

Table 10. (EXAMPLE) Economic value of avoided plant O&M – variable.

	Prices			Costs			Disc. Costs	
Year	Utility	VOS	p.u. PV Production	Utility	VOS	Discount Factor	Utility	VOS
	($/kWh)	($/kWh)	(kWh)	($)	($)		($)	($)
2014	$0.001	$0.001	1,800	$2	$2	1.000	$2	$2
2015	$0.001	$0.001	1,791	$2	$2	0.926	$2	$2
2016	$0.001	$0.001	1,782	$2	$2	0.857	$2	$2
2017	$0.001	$0.001	1,773	$2	$2	0.794	$1	$2
2018	$0.001	$0.001	1,764	$2	$2	0.735	$1	$2
2019	$0.001	$0.001	1,755	$2	$2	0.681	$1	$1
2020	$0.001	$0.001	1,747	$2	$2	0.630	$1	$1
2021	$0.001	$0.001	1,738	$2	$2	0.583	$1	$1
2022	$0.001	$0.001	1,729	$2	$2	0.540	$1	$1
2023	$0.001	$0.001	1,721	$2	$2	0.500	$1	$1
2024	$0.001	$0.001	1,712	$2	$2	0.463	$1	$1
2025	$0.001	$0.001	1,703	$2	$2	0.429	$1	$1
2026	$0.001	$0.001	1,695	$2	$2	0.397	$1	$1
2027	$0.001	$0.001	1,686	$2	$2	0.368	$1	$1
2028	$0.001	$0.001	1,678	$2	$2	0.340	$1	$1
2029	$0.001	$0.001	1,670	$2	$2	0.315	$1	$1
2030	$0.001	$0.001	1,661	$2	$2	0.292	$1	$1
2031	$0.001	$0.001	1,653	$2	$2	0.270	$1	$1
2032	$0.001	$0.001	1,645	$2	$2	0.250	$1	$0
2033	$0.001	$0.001	1,636	$2	$2	0.232	$1	$0
2034	$0.001	$0.001	1,628	$2	$2	0.215	$1	$0
2035	$0.002	$0.001	1,620	$2	$2	0.199	$0	$0
2036	$0.002	$0.001	1,612	$2	$2	0.184	$0	$0
2037	$0.002	$0.001	1,604	$3	$2	0.170	$0	$0
2038	$0.002	$0.001	1,596	$3	$2	0.158	$0	$0

Validation: Present Value	$24	$24

Avoided Generation Capacity Cost

The solar-weighted capacity cost is based on the installed capital cost of a peaking combustion turbine and the installed capital cost of a combined cycle gas turbine, interpolated based on heat rate:

$$Cost = Cost_{CCGT} + (HeatRate_{PV} - HeatRate_{CCGT}) \times \frac{Cost_{CT} - Cost_{CCGT}}{HeatRate_{CT} - HeatRate_{CCGT}} \qquad (17)$$

Where $HeatRate_{PV}$ is the solar-weighted heat rate calculated in equation (14).

Using equation (17) with the CT/CCGT heat rates and costs from the example VOS Data Table, we calculated a solar-weighted capacity cost of $1,050 per kW. In the example, the amortized cost is $86 per kW-yr.

Table 11 illustrates how utility costs are calculated by taking into account the degrading heat rate of the marginal unit and PV. For example, in year 2015, the utility cost is $86 per kW-yr x 0.999 / 0.995 to give $85 for each unit of effective PV capacity. Utility prices are back-calculated for reference from the per unit PV production. Again, the VOS price is selected to give the same total discounted cost as the utility costs for the Generation Capacity Cost component.

Table 11. (EXAMPLE) Economic value of avoided generation capacity cost.

				Prices			Costs			Disc. Costs	
Year	Capacity Cost	Utility Capacity	PV Capacity	Utility	VOS	p.u. PV Production	Utility	VOS	Discount Factor	Utility	VOS
	($/kW-yr)	(p.u.)	(kW)	($/kWh)	($/kWh)	(kWh)	($)	($)		($)	($)
2014	$86	1.000	1.000	$0.048	$0.048	1800	$86	$87	1.000	$86	$87
2015	$86	0.999	0.995	$0.048	$0.048	1791	$85	$86	0.926	$79	$80
2016	$86	0.998	0.990	$0.048	$0.048	1782	$85	$86	0.857	$73	$73
2017	$86	0.997	0.985	$0.048	$0.048	1773	$85	$85	0.794	$67	$68
2018	$86	0.996	0.980	$0.048	$0.048	1764	$84	$85	0.735	$62	$62
2019	$86	0.995	0.975	$0.048	$0.048	1755	$84	$84	0.681	$57	$57
2020	$86	0.994	0.970	$0.048	$0.048	1747	$84	$84	0.630	$53	$53
2021	$86	0.993	0.966	$0.048	$0.048	1738	$83	$84	0.583	$49	$49
2022	$86	0.992	0.961	$0.048	$0.048	1729	$83	$83	0.540	$45	$45
2023	$86	0.991	0.956	$0.048	$0.048	1721	$83	$83	0.500	$41	$41
2024	$86	0.990	0.951	$0.048	$0.048	1712	$82	$82	0.463	$38	$38
2025	$86	0.989	0.946	$0.048	$0.048	1703	$82	$82	0.429	$35	$35
2026	$86	0.988	0.942	$0.048	$0.048	1695	$82	$81	0.397	$32	$32
2027	$86	0.987	0.937	$0.048	$0.048	1686	$81	$81	0.368	$30	$30
2028	$86	0.986	0.932	$0.048	$0.048	1678	$81	$81	0.340	$28	$27
2029	$86	0.985	0.928	$0.048	$0.048	1670	$81	$80	0.315	$25	$25
2030	$86	0.984	0.923	$0.048	$0.048	1661	$80	$80	0.292	$23	$23
2031	$86	0.983	0.918	$0.049	$0.048	1653	$80	$79	0.270	$22	$21
2032	$86	0.982	0.914	$0.049	$0.048	1645	$80	$79	0.250	$20	$20
2033	$86	0.981	0.909	$0.049	$0.048	1636	$80	$79	0.232	$18	$18
2034	$86	0.980	0.905	$0.049	$0.048	1628	$79	$78	0.215	$17	$17
2035	$86	0.979	0.900	$0.049	$0.048	1620	$79	$78	0.199	$16	$15
2036	$86	0.978	0.896	$0.049	$0.048	1612	$79	$77	0.184	$14	$14
2037	$86	0.977	0.891	$0.049	$0.048	1604	$78	$77	0.170	$13	$13
2038	$86	0.976	0.887	$0.049	$0.048	1596	$78	$77	0.158	$12	$12
							Validation: Present Value			**$958**	**$958**

Avoided Reserve Capacity Cost

An example of the calculation of avoided reserve capacity cost is shown in Table 12. This is identical to the generation capacity cost calculation, except utility costs are multiplied by the reserve capacity margin. In the example, the reserve capacity margin is 15%, so the utility cost for 2014 is calculated as $86 per unit effective capacity x 15% = $13. The rest of the calculation is identical to the capacity cost calculation.

Avoided Transmission Capacity Cost

Avoided transmission costs are calculated the same way as avoided generation costs except in two ways. First, transmission capacity is assumed not to degrade over time (PV degradation is still accounted for). Second, avoided transmission capacity costs are calculated based on the utility's 5-year average MISO OATT Schedule 9 charge in Start Year USD, e.g., in 2014 USD if year one of the VOS tariff was 2014. Table 13 shows the example calculation.

Table 12. (EXAMPLE) Economic value of avoided reserve capacity cost.

Year	Capacity Cost	Gen. Capacity	PV Capacity	Prices Utility	Prices VOS	p.u. PV Production	Costs Utility	Costs VOS	Discount Factor	Disc. Costs Utility	Disc. Costs VOS
	($/kW-yr)	(p.u.)	(kW)	($/kWh)	($/kWh)	(kWh)	($)	($)		($)	($)
2014	$86	1.000	1.000	$0.007	$0.007	1800	$13	$13	1.000	$13	$13
2015	$86	0.999	0.999	$0.007	$0.007	1791	$13	$13	0.926	$12	$12
2016	$86	0.998	0.994	$0.007	$0.007	1782	$13	$13	0.857	$11	$11
2017	$86	0.997	0.986	$0.007	$0.007	1773	$13	$13	0.794	$10	$10
2018	$86	0.996	0.971	$0.007	$0.007	1764	$13	$13	0.735	$9	$9
2019	$86	0.995	0.951	$0.007	$0.007	1755	$13	$13	0.681	$9	$9
2020	$86	0.994	0.927	$0.007	$0.007	1747	$13	$13	0.630	$8	$8
2021	$86	0.993	0.899	$0.007	$0.007	1738	$13	$13	0.583	$7	$7
2022	$86	0.992	0.872	$0.007	$0.007	1729	$12	$12	0.540	$7	$7
2023	$86	0.991	0.842	$0.007	$0.007	1721	$12	$12	0.500	$6	$6
2024	$86	0.990	0.809	$0.007	$0.007	1712	$12	$12	0.463	$6	$6
2025	$86	0.989	0.786	$0.007	$0.007	1703	$12	$12	0.429	$5	$5
2026	$86	0.988	0.762	$0.007	$0.007	1695	$12	$12	0.397	$5	$5
2027	$86	0.987	0.737	$0.007	$0.007	1686	$12	$12	0.368	$4	$4
2028	$86	0.986	0.713	$0.007	$0.007	1678	$12	$12	0.340	$4	$4
2029	$86	0.985	0.688	$0.007	$0.007	1670	$12	$12	0.315	$4	$4
2030	$86	0.984	0.663	$0.007	$0.007	1661	$12	$12	0.292	$4	$3
2031	$86	0.983	0.637	$0.007	$0.007	1653	$12	$12	0.270	$3	$3
2032	$86	0.982	0.612	$0.007	$0.007	1645	$12	$12	0.250	$3	$3
2033	$86	0.981	0.587	$0.007	$0.007	1636	$12	$12	0.232	$3	$3
2034	$86	0.980	0.563	$0.007	$0.007	1628	$12	$12	0.215	$3	$3
2035	$86	0.979	0.543	$0.007	$0.007	1620	$12	$12	0.199	$2	$2
2036	$86	0.978	0.523	$0.007	$0.007	1612	$12	$12	0.184	$2	$2
2037	$86	0.977	0.504	$0.007	$0.007	1604	$12	$12	0.170	$2	$2
2038	$86	0.976	0.485	$0.007	$0.007	1596	$12	$12	0.158	$2	$2
							Validation: Present Value			**$144**	**$144**

Table 13. (EXAMPLE) Economic value of avoided transmission capacity cost.

Year	Capacity Cost ($/kW-yr)	Trans. Capacity (p.u.)	PV Capacity (kW)	Prices: Utility ($/kWh)	Prices: VOS ($/kWh)	p.u. PV Production (kWh)	Costs: Utility ($)	Costs: VOS ($)	Discount Factor	Disc. Costs: Utility ($)	Disc. Costs: VOS ($)
2014	$33	1.000	1.000	$0.018	$0.018	1800	$33	$33	1.000	$33	$33
2015	$33	1.000	0.995	$0.018	$0.018	1791	$33	$33	0.926	$30	$30
2016	$33	1.000	0.990	$0.018	$0.018	1782	$33	$33	0.857	$28	$28
2017	$33	1.000	0.985	$0.018	$0.018	1773	$33	$33	0.794	$26	$26
2018	$33	1.000	0.980	$0.018	$0.018	1764	$32	$32	0.735	$24	$24
2019	$33	1.000	0.975	$0.018	$0.018	1755	$32	$32	0.681	$22	$22
2020	$33	1.000	0.970	$0.018	$0.018	1747	$32	$32	0.630	$20	$20
2021	$33	1.000	0.966	$0.018	$0.018	1738	$32	$32	0.583	$19	$19
2022	$33	1.000	0.961	$0.018	$0.018	1729	$32	$32	0.540	$17	$17
2023	$33	1.000	0.956	$0.018	$0.018	1721	$32	$32	0.500	$16	$16
2024	$33	1.000	0.951	$0.018	$0.018	1712	$31	$31	0.463	$15	$15
2025	$33	1.000	0.946	$0.018	$0.018	1703	$31	$31	0.429	$13	$13
2026	$33	1.000	0.942	$0.018	$0.018	1695	$31	$31	0.397	$12	$12
2027	$33	1.000	0.937	$0.018	$0.018	1686	$31	$31	0.368	$11	$11
2028	$33	1.000	0.932	$0.018	$0.018	1678	$31	$31	0.340	$10	$10
2029	$33	1.000	0.928	$0.018	$0.018	1670	$31	$31	0.315	$10	$10
2030	$33	1.000	0.923	$0.018	$0.018	1661	$30	$30	0.292	$9	$9
2031	$33	1.000	0.918	$0.018	$0.018	1653	$30	$30	0.270	$8	$8
2032	$33	1.000	0.914	$0.018	$0.018	1645	$30	$30	0.250	$8	$8
2033	$33	1.000	0.909	$0.018	$0.018	1636	$30	$30	0.232	$7	$7
2034	$33	1.000	0.905	$0.018	$0.018	1628	$30	$30	0.215	$6	$6
2035	$33	1.000	0.900	$0.018	$0.018	1620	$30	$30	0.199	$6	$6
2036	$33	1.000	0.896	$0.018	$0.018	1612	$30	$30	0.184	$5	$5
2037	$33	1.000	0.891	$0.018	$0.018	1604	$29	$29	0.170	$5	$5
2038	$33	1.000	0.887	$0.018	$0.018	1596	$29	$29	0.158	$5	$5
							Validation: Present Value			**$365**	**$365**

Avoided Distribution Capacity Cost

Avoided distribution capacity costs may be calculated in either of two ways:

- **System-wide Avoided Costs**. These are calculated using utility-wide costs and lead to a VOS rate that is "averaged" and applicable to all solar customers. This method is described below in the methodology.

- **Location-specific Avoided Costs**. These are calculated using location-specific capacity-related project costs and associated capacity additions , growth rates, etc., andwhich lead to location-specific VOS rates. This method provides the utility with a means for offering a higher-value VOS rate in areas where capacity is most needed (areas of highest value). The details of this method are site specific and not included in the methodology, however they are to be implemented in accordance with the requirements set for the below.

System-wide Avoided Costs

System--wide costs are determined using actual data from each of the last two10 years and forecasted budget data for each of the next three future years.peak growth rates are based on the utility's estimated future growth over the next 15 years. The data shall consist of capacity-related distribution capacity costs and associated capacity additions these projects provide. The costs and growth rate must be taken over the same time period because the historical investments must be tied to the growth associated with those investments.

All capacity-related costs for each year for FERC accounts 360, 361, 362, 365, 366, and 367 should be included. These costs, however, should be adjusted to consider only capacity-related amounts. As such, the capacity- related percentages shown in Table 14 will be utility specific.

The distribution capacity cost per kW should be calculated by dividing the capacity-related distribution project costs by the associated capacity additions and then multiplying the total by the deferral factor. For example, if the distribution capacity project costs totaled $40 million and those projects make 100 MWs of capacity available then the distribution cost per kW is calculated as follows: $40,000,000 divided by 100,000 kW and then multiplied by 50% or $200 per kW.

$$\text{Cost per kW} = \text{Capacity Cost} / \text{Capacity Additions} \times \text{Deferral Factor} \qquad (18)$$

Table 14. (EXAMPLE) Determination of deferrable costs.

Account	Account Name	Additions ($) [A]	Retirements ($) [R]	Net Additions ($) = [A] - [R]	Capacity Related?	Deferrable ($)
	DISTRIBUTION PLANT					
360	Land and Land Rights	13,931,928	233,588	13,698,340	100%	13,698,340
361	Structures and Improvements	35,910,551	279,744	35,630,807	100%	35,630,807
362	Station Equipment	478,389,052	20,808,913	457,580,139	100%	457,580,139
363	Storage Battery Equipment					
364	Poles, Towers, and Fixtures	310,476,864	9,489,470	300,987,394		
365	Overhead Conductors and Devices	349,818,997	22,090,380	327,728,617	25%	81,932,154
366	Underground Conduit	210,115,953	10,512,018	199,603,935	25%	49,900,984
367	Underground Conductors and Devices	902,527,963	32,232,966	870,294,997	25%	217,573,749
368	Line Transformers	389,984,149	19,941,075	370,043,074		
369	Services	267,451,206	5,014,559	262,436,647		
370	Meters	118,461,196	4,371,827	114,089,369		
371	Installations on Customer Premises	22,705,193		22,705,193		
372	Leased Property on Customer Premises					
373	Street Lighting and Signal Systems	53,413,993	3,022,447	50,391,546		
374	Asset Retirement Costs for Distribution Plant	15,474,098	2,432,400	13,041,698		
TOTAL		3,168,661,143	130,429,387	3,038,231,756		$856,316,173

Cost per unit growth ($ per kW) is calculated by taking all of the total deferrable cost for each year, adjusting for inflation, and dividing by the kW increase in peak annual load over the 10 years.

Future growth in peak load is based on the utility's estimated future growth over the next 15 years. It is calculated using the ratio of peak loads of the fifteenth year (year 15) and the peak load from the first year (year 1):

$$GrowthRate = (P_{15} / P_1)^{1/14} \quad (18)$$

If the resulting growth rate is zero or negative (before adding solar PV), set the avoided distribution capacity to zero.

A sample economic value calculation is presented in Table 15. The distribution cost for the first year ($200 per kW in the example) is taken from the analysis of historical and forecasted distribution cost, and estimated growth associated capacity and deferral factor as described above. This cost is escalated each year using the rate in the VOS Data Table.

For each future year, the amount of new distribution capacity is calculated based on the growth rate, and this is multiplied by the cost per kW to get the cost for the year. The total discounted cost is calculated ($149M) and amortized over the 25 years.

PV is assumed to be installed in sufficient capacity to allow this investment stream to be deferred for one year. The total discounted cost of the deferred time series is calculated ($140M) and amortized.

Utility costs are calculated using the difference between the amortized costs of the conventional plan and the amortized cost of the deferred plan. For example, the utility cost for 2022 is ($14M - $13M)/54MW x 1000 W/kW = $14 per effective kW of PV. As before, utility prices are back-calculated using PV production, and the VOS component rate is calculated such that the total discounted amount equals the discounted utility cost.

Location-specific Avoided Costs

As an alternative to system-wide costs for distribution, location-specific costs may be used. When calculating location-specific costs, the calculation should follow the same method of the system-wide avoided cost method, but use local capacity additionstechnical and cost data. The calculation should satisfy the following requirements:

- The distribution cost VOS should be calculated for each distribution planning area, defined as the minimum area in which capacity needs cannot be met by transferring loads internally from one circuit to another.
- Distribution loads (the sum of all relevant feeders), peak load growth rates and capital costs and associated project capacity should be based on the distribution planning area.

- Local Fleet Production Shapes may be used, if desired. Alternatively, the system-level Fleet Production Shape may be used.
- Anticipated capital costs should be evaluated based on capacity related investments only (as above) using budgetary engineering cost estimates. ~~All anticipated capital investments in the planning area should be included. Planned capital investments should be assumed to meet capacity requirements for the number of years defined by the amount of new capacity added (in MW) divided by the local growth rate (MW per year). Beyond this time period, which is beyond the planning horizon, new capacity investments should be assumed each year using the system-wide method.~~
- Planning areas for which engineering cost estimates are not available may be combined, and the VOS calculated using the system-wide method.

Table 15. (EXAMPLE) Economic value of avoided distribution capacity cost, system-wide.

		Conventional Distribution Planning				Deferred Distribution Planning			
Year	Distribution Cost	New Dist. Capacity	Capital Cost	Disc. Capital Cost	Amortized	Def. Dist. Capacity	Def. Capital Cost	Disc. Capital Cost	Amortized
	($/kW)	(MW)	($M)	($M)	$M/yr	(MW)	($M)	($M)	$M/yr
2014	$200	50	$10	$10	$14				$13
2015	$204	50	$10	$9	$14	50	$10	$9	$13
2016	$208	51	$11	$9	$14	50	$10	$9	$13
2017	$212	51	$11	$9	$14	51	$11	$9	$13
2018	$216	52	$11	$8	$14	51	$11	$8	$13
2019	$221	52	$11	$8	$14	52	$11	$8	$13
2020	$225	53	$12	$7	$14	52	$12	$7	$13
2021	$230	53	$12	$7	$14	53	$12	$7	$13
2022	$234	54	$13	$7	$14	53	$12	$7	$13
2023	$239	54	$13	$6	$14	54	$13	$6	$13
2024	$244	55	$13	$6	$14	54	$13	$6	$13
2025	$249	55	$14	$6	$14	55	$14	$6	$13
2026	$254	56	$14	$6	$14	55	$14	$6	$13
2027	$259	56	$15	$5	$14	56	$14	$5	$13
2028	$264	57	$15	$5	$14	56	$15	$5	$13
2029	$269	57	$15	$5	$14	57	$15	$5	$13
2030	$275	58	$16	$5	$14	57	$16	$5	$13
2031	$280	59	$16	$4	$14	58	$16	$4	$13
2032	$286	59	$17	$4	$14	59	$17	$4	$13
2033	$291	60	$17	$4	$14	59	$17	$4	$13
2034	$297	60	$18	$4	$14	60	$18	$4	$13
2035	$303	61	$18	$4	$14	60	$18	$4	$13
2036	$309	62	$19	$4	$14	61	$19	$3	$13
2037	$315	62	$20	$3	$14	62	$19	$3	$13
2038	$322	63	$20	$3	$14	62	$20	$3	$13
2039	$328					63	$21	$3	
				$149				$140	

CONTINUED Table 15. (EXAMPLE) Economic value of avoided distribution capacity cost, system-wide.

		Costs			Disc. Costs		Prices	
Year	p.u. PV Production	Utility	VOS	Discount Factor	Utility	VOS	Utility	VOS
	(kWh)	($)	($)		($)	($)	($/kWh)	($/kWh)
2014	1800	$16	$15	1.000	$16	$15	$0.009	$0.008
2015	1791	$15	$15	0.926	$14	$14	$0.009	$0.008
2016	1782	$15	$15	0.857	$13	$13	$0.009	$0.008
2017	1773	$15	$15	0.794	$12	$12	$0.009	$0.008
2018	1764	$15	$15	0.735	$11	$11	$0.009	$0.008
2019	1755	$15	$15	0.681	$10	$10	$0.008	$0.008
2020	1747	$15	$15	0.630	$9	$9	$0.008	$0.008
2021	1738	$15	$15	0.583	$9	$8	$0.008	$0.008
2022	1729	$14	$14	0.540	$8	$8	$0.008	$0.008
2023	1721	$14	$14	0.500	$7	$7	$0.008	$0.008
2024	1712	$14	$14	0.463	$7	$7	$0.008	$0.008
2025	1703	$14	$14	0.429	$6	$6	$0.008	$0.008
2026	1695	$14	$14	0.397	$6	$6	$0.008	$0.008
2027	1686	$14	$14	0.368	$5	$5	$0.008	$0.008
2028	1678	$14	$14	0.340	$5	$5	$0.008	$0.008
2029	1670	$13	$14	0.315	$4	$4	$0.008	$0.008
2030	1661	$13	$14	0.292	$4	$4	$0.008	$0.008
2031	1653	$13	$14	0.270	$4	$4	$0.008	$0.008
2032	1645	$13	$14	0.250	$3	$3	$0.008	$0.008
2033	1636	$13	$14	0.232	$3	$3	$0.008	$0.008
2034	1628	$13	$14	0.215	$3	$3	$0.008	$0.008
2035	1620	$13	$14	0.199	$3	$3	$0.008	$0.008
2036	1612	$13	$13	0.184	$2	$2	$0.008	$0.008
2037	1604	$12	$13	0.170	$2	$2	$0.008	$0.008
2038	1596	$12	$13	0.158	$2	$2	$0.008	$0.008
2039								

Validation: Present Value	**$166**	**$166**

Avoided Environmental Cost

Environmental costs are included as a required component and are based on existing Minnesota and federal externality costs. CO_2 and non-CO_2 natural gas emissions factors (lb per MM BTU of natural gas) are from the EPA[17] and NaturalGas.org.[18] Avoided environmental costs are based on the federal social cost of CO_2 emissions[19] plus the Minnesota PUC-established externality costs for non-CO_2 emissions.[20]

The externality cost of CO_2 emissions shown in Table 4 are calculated as follows. The Social Cost of Carbon (CO_2) values for each year through 2050 are published in 2007 dollars per metric ton.[21] These costs are adjusted for inflation (converted to current dollars), converted to dollars per short ton, and then converted to cost per unit fuel consumption using the assumed values in Table 16.

For example, the CO_2 externality cost for 2020 (3.0% discount rate, average) is $43 per metric ton of CO_2 emissions in 2007 dollars. This is converted to current dollars by multiplying by a CPI adjustment factor; for 2014, the CPI adjustment factor is of 1.13.[22] The resulting CO_2 costs per metric ton in current dollars are then converted to dollars per short ton by dividing by 1.102. Finally, the costs are escalated using the general escalation rate of 2.75% per year to give $54.76 per ton. The $54.76 per ton of CO_2 is then divided by 2000 pounds per ton and multiplied by 117.0 pounds of CO_2 per MMBtu = $3.204 per MMBtu in 2020 dollars.

Table 16. Natural Gas Emissions.

	NG Emissions (lb/MMBtu)
PM_{10}	0.007
CO	0.04
NO_X	0.092
Pb	0.00
CO_2	117.0

[17] http://www.epa.gov/climatechange/ghgemissions/ind-assumptions.html and http://www.epa.gov/ttnchie1/ap42/
[18] http://www.naturalgas.org/environment/naturalgas.asp
[19] See http://www.epa.gov/climatechange/EPAactivities/economics/scc.html, technical support document appendix, May 2013.
[20] "Notice of Updated Environmental Externality Values," issued June 5, 2013, PUC docket numbers E-999/CI-93-583 and E-999/CI-00-1636.
[21] The annual Social Cost of Carbon values are listed in table A1 of the Social Cost of Carbon Technical Support Document. The Technical Support Document can be found at: http://www.whitehouse.gov/sites/default/files/omb/assets/inforeg/technical-update-social-cost-of-carbon-for-regulator-impact-analysis.pdf.
[22] The CPI adjustment factor can be calculated through the Bureau of Labor Statistics CPI inflation calculator. The calculator can be found at: http://data.bls.gov/cgi-bin/cpicalc.pl.

Pollutants other than CO_2 are calculated using the Minnesota externality costs using the following method. Externality costs are calculated as the midpoint of the low and high values for the urban scenario, adjusted to current dollars, and converted to a fuel-based value using Table 16. Each utility may select the set of non-CO_2 externality values that is most appropriate for their service territory (e.g. urban or metropolitan fringe or rural).

For the example, MN PUC's published 2012 urban externality values for PM10 are $6,291 per ton (low case) and $9,056 per ton (high case). These are averaged to be ($6291+$9056)/2 = $7674 per ton of PM10 emissions. For 2020, these are escalated using the general escalation rate of 2.75% per year to $9,533 per ton. The $9,533 per ton of PM10 is then divided by 2000 pounds per ton and multiplied by 0.007 pounds of PM10 per MMBtu to arrive at a PM10 externality cost of $0.033 per MMBtu. Similar calculations are done for the other pollutants.

In the example shown in Table 17, the environmental cost is the sum of the costs of all pollutants. For example, in 2020, the total cost of $3.287 per MMBtu corresponds to the 2020 total cost in Table 4. This cost is multiplied by the heat rate for the year (see Avoided Fuel Cost calculation) and divided by 10^6 (to convert Btus to MMBtus), which results in the environmental cost in dollars per kWh for each year. The remainder of the calculation follows the same method as the avoided variable O&M costs but using the environmental discount factor (see Discount Factors for a description of the environmental discount factor and its calculation).

Avoided Voltage Control Cost

This is reserved for future updates to the methodology.

Solar Integration Cost

This is reserved for future updates to the methodology.

Table 17. (EXAMPLE) Economic value of avoided environmental cost.

Year	Env. Cost	Heat Rate	Prices		p.u. PV	Costs		Discount	Disc. Costs	
			Utility	VOS	Production	Utility	VOS	Factor	Utility	VOS
	($/MMBtu)	(Btu/kWh)	($/kWh)	($/kWh)	(kWh)	($)	($)		($)	($)
2014	2.022	8000	$0.016	$0.027	1,800	$29	$48	1.000	$29	$48
2015	2.131	8008	$0.017	$0.027	1,791	$31	$48	0.945	$29	$45
2016	2.245	8016	$0.018	$0.027	1,782	$32	$47	0.893	$29	$42
2017	2.363	8024	$0.019	$0.027	1,773	$34	$47	0.844	$28	$40
2018	2.487	8032	$0.020	$0.027	1,764	$35	$47	0.797	$28	$37
2019	2.615	8040	$0.021	$0.027	1,755	$37	$47	0.753	$28	$35
2020	2.749	8048	$0.022	$0.027	1,747	$39	$46	0.712	$28	$33
2021	2.888	8056	$0.023	$0.027	1,738	$40	$46	0.673	$27	$31
2022	3.032	8064	$0.024	$0.027	1,729	$42	$46	0.636	$27	$29
2023	3.182	8072	$0.026	$0.027	1,721	$44	$46	0.601	$27	$27
2024	3.338	8080	$0.027	$0.027	1,712	$46	$46	0.567	$26	$26
2025	3.501	8088	$0.028	$0.027	1,703	$48	$45	0.536	$26	$24
2026	3.669	8097	$0.030	$0.027	1,695	$50	$45	0.507	$26	$23
2027	3.770	8105	$0.031	$0.027	1,686	$52	$45	0.479	$25	$21
2028	3.950	8113	$0.032	$0.027	1,678	$54	$45	0.452	$24	$20
2029	4.138	8121	$0.034	$0.027	1,670	$56	$44	0.427	$24	$19
2030	4.332	8129	$0.035	$0.027	1,661	$59	$44	0.404	$24	$18
2031	4.534	8137	$0.037	$0.027	1,653	$61	$44	0.382	$23	$17
2032	4.744	8145	$0.039	$0.027	1,645	$64	$44	0.361	$23	$16
2033	4.962	8153	$0.040	$0.027	1,636	$66	$44	0.341	$23	$15
2034	5.189	8162	$0.042	$0.027	1,628	$69	$43	0.322	$22	$14
2035	5.424	8170	$0.044	$0.027	1,620	$72	$43	0.304	$22	$13
2036	5.668	8178	$0.046	$0.027	1,612	$75	$43	0.287	$21	$12
2037	5.922	8186	$0.048	$0.027	1,604	$78	$43	0.272	$21	$12
2038	6.185	8194	$0.051	$0.027	1,596	$81	$42	0.257	$21	$11
						Validation: Present Value			**$629**	**$629**

VOS Example Calculation

The gross economic value, load match, distributed loss savings factor, and distributed PV value are combined in the required VOS Levelized Calculation Chart. An example is presented in Figure 2 using the assumptions made for the example calculation. Actual VOS results will differ from those shown in the example, but utilities will include in their application a VOS Levelized Calculation Chart in the same format. For completeness, Figure 3 (not required of the utilities) is presented showing graphically the relative importance of the components in the example.

Figure 3. (EXAMPLE) VOS Levelized Calculation Chart (Required).

25 Year Levelized Value	Economic Value ($/kWh)	Load Match (No Losses) (%)	Distributed Loss Savings (%)	Distributed PV Value ($/kWh)
Avoided Fuel Cost	$0.056		8%	$0.061
Avoided Plant O&M - Fixed	$0.003	40%	9%	$0.001
Avoided Plant O&M - Variable	$0.001		8%	$0.001
Avoided Gen Capacity Cost	$0.048	40%	9%	$0.021
Avoided Reserve Capacity Cost	$0.007	40%	9%	$0.003
Avoided Trans. Capacity Cost	$0.018	40%	9%	$0.008
Avoided Dist. Capacity Cost	$0.008	30%	5%	$0.003
Avoided Environmental Cost	$0.027		8%	$0.029
Avoided Voltage Control Cost				
Solar Integration Cost				
				$0.127

Having calculated the levelized VOS credit, an inflation-adjusted VOS can then be found. An EXAMPLE inflation-adjusted VOS is provided in Figure 5 by using the general escalation rate as the annual inflation rate for all years of the analysis period. Both the inflation-adjusted VOS and the levelized VOS in Figure 5 represent the same long-term value. The methodology requires that the inflation-adjusted (real) VOS be used and updated annually to account for the current year's inflation rate.

To calculate the inflation-adjusted VOS for the first year, the products of the levelized VOS, PV production and the discount factor are summed for each year of the analysis period and then divided by the sum of the products of the escalation factor, PV production, and the discount factor for each year of the analysis period, as shown below in Equation (17).

Figure 4. (EXAMPLE) Levelized value components.

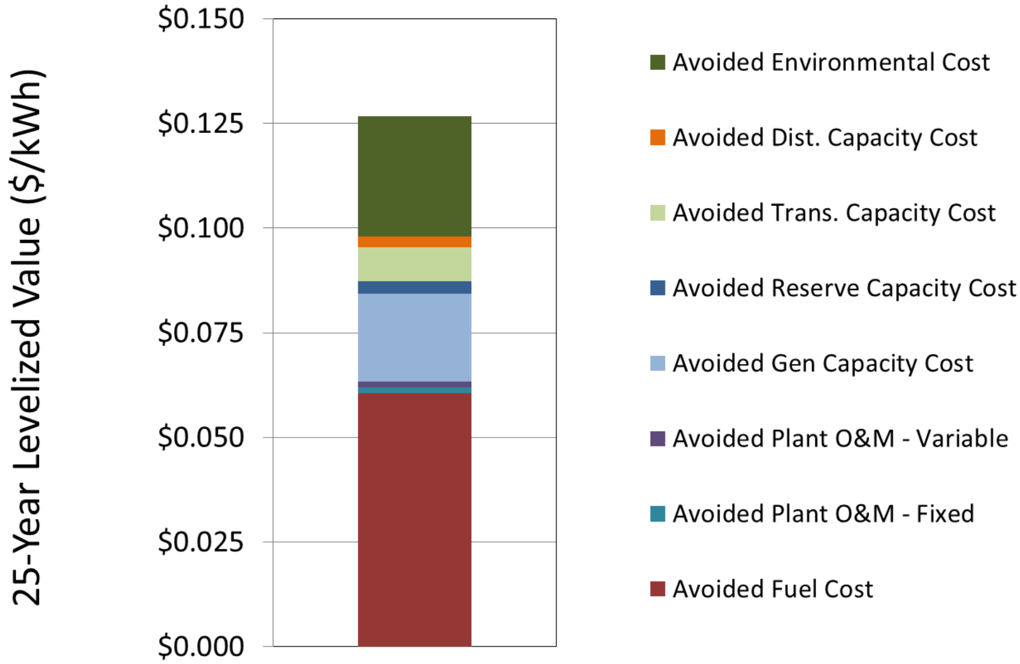
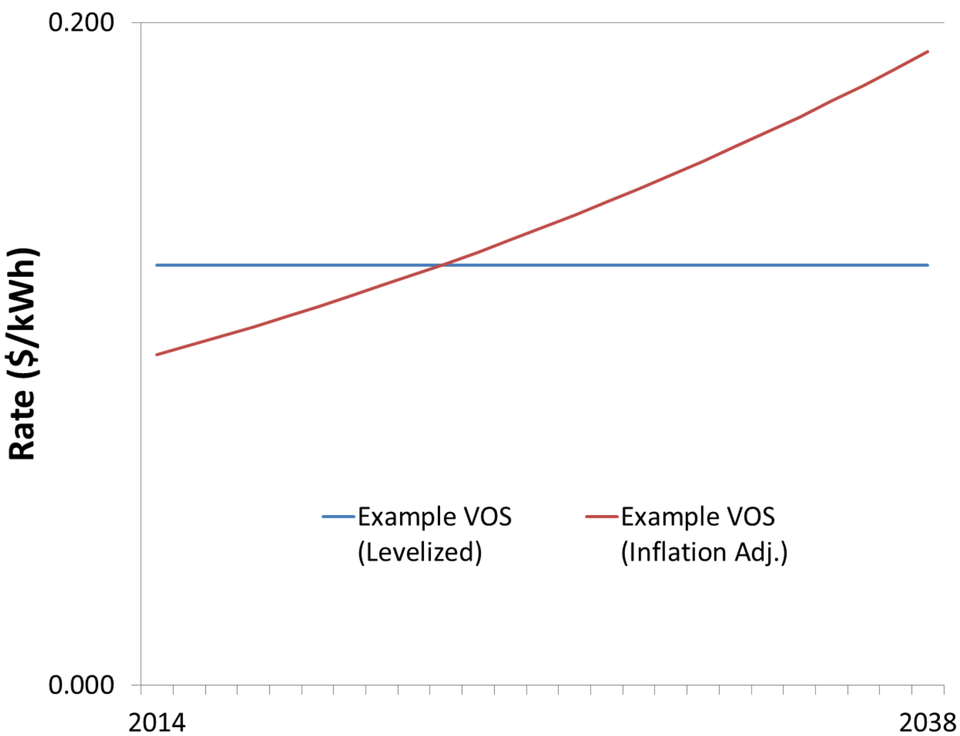


Figure5. (EXAMPLE) Inflation-Adjusted VOS.



$$InflationAdjustedVOS_{Year0}\left(\frac{\$}{kWh}\right) = \frac{\sum_i LevelizedVOS \times PVProduction_i \times DiscountFactor_i}{\sum_i EscalationFactor_i \times PVProduction_i \times DiscountFactor_i} \quad (19)$$

Once the first-year inflation-adjusted VOS is calculated, the value will then be updated on an annual basis in accordance with the observed inflation-rate. Table 18 provides the calculation of the EXAMPLE inflation-adjusted VOS shown in Figure 5. In this EXAMPLE, the inflation rate in future years is set equal to the general escalation rate of 2.75%.

Table 18. (EXAMPLE) Calculation of inflation-adjusted VOS.

Year	Discount Factor	Escalation Factor	Example VOS (Levelized)	Disc.	Example VOS (Inflation Adj.)	Disc.
2014	1.000	1.000	0.127	0.127	0.100	0.100
2015	0.926	1.027	0.127	0.117	0.102	0.095
2016	0.857	1.056	0.127	0.109	0.105	0.090
2017	0.794	1.085	0.127	0.101	0.108	0.086
2018	0.735	1.115	0.127	0.093	0.111	0.082
2019	0.681	1.145	0.127	0.086	0.114	0.078
2020	0.630	1.177	0.127	0.080	0.117	0.074
2021	0.583	1.209	0.127	0.074	0.121	0.070
2022	0.540	1.242	0.127	0.068	0.124	0.067
2023	0.500	1.276	0.127	0.063	0.127	0.064
2024	0.463	1.311	0.127	0.059	0.131	0.061
2025	0.429	1.347	0.127	0.054	0.134	0.058
2026	0.397	1.384	0.127	0.050	0.138	0.055
2027	0.368	1.422	0.127	0.047	0.142	0.052
2028	0.340	1.462	0.127	0.043	0.146	0.050
2029	0.315	1.502	0.127	0.040	0.150	0.047
2030	0.292	1.543	0.127	0.037	0.154	0.045
2031	0.270	1.585	0.127	0.034	0.158	0.043
2032	0.250	1.629	0.127	0.032	0.162	0.041
2033	0.232	1.674	0.127	0.029	0.167	0.039
2034	0.215	1.720	0.127	0.027	0.172	0.037
2035	0.199	1.767	0.127	0.025	0.176	0.035
2036	0.184	1.815	0.127	0.023	0.181	0.033
2037	0.170	1.865	0.127	0.022	0.186	0.032
2038	0.158	1.917	0.127	0.020	0.191	0.030
				1.461		1.461

Glossary

Table 19. Input data definitions

Input Data	Used in Methodology Section	Definition
Annual Energy	PV Energy Production	The annual PV production (kWh per year) per Marginal PV Resource (initially 1 kW-AC) in the first year (before any PV degradation) of the marginal PV resource. This is calculated in the Annual Energy section of PV Energy Production and used in the Equipment Degradation section.
Capacity-related distribution capital cost	Avoided Distribution Capacity Cost	This is described more fully in the Avoided Distribution Capacity Cost section.
Capacity-related transmission capital cost	Avoided Transmission Capacity Cost	The cost per kW of new construction of transmission, including lines, towers, insulators, transmission substations, etc. Only capacity-related costs should be included.
Discount rate (WACC)	Multiple	The utility's weighted average cost of capital, including interest on bonds and shareholder return.
Distribution capital cost escalation	Avoided Distribution Capacity Cost	Used to calculate future distribution costs.
ELCC (no loss), PLR (no loss)	Load Match Factors	The "Effective Load Carrying Capability" and the "Peak Load Reduction" of a PV resource expressed as percentages of rated capacity (kW-AC). These are described more fully in the Load Match section.
Environmental Costs	Avoided Environmental Cost	The costs required to calculate environmental impacts of conventional generation. These are described more fully in the Avoided Environmental Cost section

Input Data	Used in Methodology Section	Definition
Environmental Discount Rate	Avoided Environmental Cost	The societal discount rate used to calculate the present value of future environmental costs.
Fuel Price Overhead	Avoided Fuel Cost	The difference in cost of fuel as delivered to the plant and the cost of fuel as available in market prices. This cost reflects transmission, delivery, and taxes.
General escalation rate	Avoided Environmental Cost, Example Results	The annual escalation rate corresponding to the most recent 25 years of CPI index data[23], used to convert constant dollar environmental costs into current dollars and to translate levelized VOS into inflation-adjusted VOS.
Generation Capacity Degradation	Avoided Generation Capacity Cost	The percentage decrease in the generation capacity per year
Generation Life	Avoided Generation Capacity Cost	The assumed service life of new generation assets.
Guaranteed NG Fuel Prices	Avoided Fuel Cost	The annual average prices to be used when the utility elects to use the Futures Market option. These are not applicable when the utility elects to use options other than the Futures Market option. They are calculated as the annual average of monthly NYMEX NG futures[24].
Heat rate degradation	Avoided Generation Capacity Cost	The percentage increase in the heat rate (BTU per kWh) per year

[23] www.bls.gov.

[24] See for example http://futures.tradingcharts.com/marketquotes/NG.html.

Input Data	Used in Methodology Section	Definition
Installed cost and heat rate for CT and CCGT	Avoided Generation Capacity Cost	The capital costs for these units (including all construction costs, land, ad valorem taxes, etc.) and their heat rates.
Loss Savings (Energy, PLR, and ELCC)	Loss Savings Analysis	The additional savings associated with Energy, PRL and ELCC, expressed as a percentage. These are described more fully in the Loss Savings section.
O&M cost escalation rate	Avoided Plant O&M – Fixed, Avoided Plant O&M – Variable	Used to calculate future O&M costs.
O&M fixed costs	Avoided Plant O&M – Fixed	The costs to operate and maintain the plant that are not dependent on the amount of energy generated.
O&M variable costs	Avoided Plant O&M – Variable	The costs to operate and maintain the plant (excluding fuel costs) that are dependent on the amount of energy generated.
Peak Load	Avoided Distribution Capacity Cost	The utility peak load as expected in the VOS start year.
Peak load growth rate	Avoided Distribution Capacity Cost	This is described more fully in the Avoided Distribution Capacity Cost section.
PV Degradation	Equipment Degradation Factors	The reduction in percent per year of PV capacity and PV energy due to degradation of the modules. The value of 0.5 percent is the median value of 2000 observed degradation rates.[25]

[25] D. Jordan and S. Kurtz, "Photovoltaic Degradation Rates – An Analytical Review," NREL, June 2012.

Input Data	Used in Methodology Section	Definition
PV Life	Multiple	The assumed service life of PV. This value is also used to define the study period for which avoided costs are determined and the period over which the VOS rate would apply.
Reserve planning margin	Avoided Reserve Capacity Cost	The planning margin required to ensure reliability.
Solar-weighted heat rate	Avoided Fuel Costs	This is described in the described in the Avoided Fuel Costs section.
Start Year for VOS applicability	Multiple	This is the first year in which the VOS would apply and the first year for which avoided costs are calculated.
Transmission capital cost escalation	Avoided Transmission Capacity Cost	Used to adjust costs for future capital investments.
Transmission life	Avoided Transmission Capacity Cost	The assumed service life of new transmission assets.
Treasury Yields	Escalation and Discount Rates	Yields for U.S. Treasuries, used as the basis of the risk-free discount rate calculation.[26]
Years until new transmission capacity is needed	Avoided Transmission Capacity Cost	This is used to test whether avoided costs for a given analysis year should be calculated and included.

[26] See http://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?data=yield

Certificate of Service

I, Jim Erickson, hereby certify that I have this day served copies of the foregoing document on the attached list of persons.

xx by depositing a true and correct copy thereof, properly enveloped with postage paid in the United States mail at Minneapolis, Minnesota

xx electronic filing

Docket No. **E999/M-14-65**
E002/M-13-867

Dated this 2nd day of August 2019

/s/

____
Jim Erickson
Regulatory Administrator

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Michael	Allen	michael.allen@allenergysolar.com	All Energy Solar	721 W 26th st Suite 211 Minneapolis, Minnesota 55405	Electronic Service	No	SPL_SL_14-65_Interested Parties
Christopher	Anderson	canderson@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022191	Electronic Service	No	SPL_SL_14-65_Interested Parties
Mara	Ascheman	mara.k.ascheman@xcelenergy.com	Xcel Energy	414 Nicollet Mall Fl 5 Minneapolis, MN 55401	Electronic Service	No	SPL_SL_14-65_Interested Parties
John	Aune	johna@bluehorizonsolar.com	Blue Horizon Energy	171 Cheshire Ln Ste 500 Plymouth, MN 55441	Electronic Service	No	SPL_SL_14-65_Interested Parties
Kenneth	Baker	Ken.Baker@walmart.com	Wal-Mart Stores, Inc.	2001 SE 10th St. Bentonville, AR 72716-5530	Electronic Service	No	SPL_SL_14-65_Interested Parties
Gail	Baranko	gail.baranko@xcelenergy.com	Xcel Energy	414 Nicollet Mall7th Floor Minneapolis, MN 55401	Electronic Service	No	SPL_SL_14-65_Interested Parties
Peter	Beithon	pbeithon@otpco.com	Otter Tail Power Company	P.O. Box 496 215 South Cascade Street Fergus Falls, MN 565380496	Electronic Service	No	SPL_SL_14-65_Interested Parties
Sara	Bergan	sebergan@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	SPL_SL_14-65_Interested Parties
James J.	Bertrand	james.bertrand@stinson.com	STINSON LLP	50 S 6th St Ste 2600 Minneapolis, MN 55402	Electronic Service	No	SPL_SL_14-65_Interested Parties
Derek	Bertsch	derek.bertsch@mrenergy.com	Missouri River Energy Services	3724 West Avera Drive PO Box 88920 Sioux Falls, SD 57109-8920	Electronic Service	No	SPL_SL_14-65_Interested Parties

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Thor	Bjork	Thor.S.Bjork@xcelenergy.com	Xcel Energy	414 Nicollet Mall Minneapolis, MN 55401	Electronic Service	No	SPL_SL_14-65_Interested Parties
Kenneth	Bradley	kbradley1965@gmail.com		2837 Emerson Ave S Apt CW112 Minneapolis, MN 55408	Electronic Service	No	SPL_SL_14-65_Interested Parties
Jon	Brekke	jbrekke@grenergy.com	Great River Energy	12300 Elm Creek Boulevard Maple Grove, MN 553694718	Electronic Service	No	SPL_SL_14-65_Interested Parties
Mark B.	Bring	mbring@otpco.com	Otter Tail Power Company	215 South Cascade Street PO Box 496 Fergus Falls, MN 565380496	Electronic Service	No	SPL_SL_14-65_Interested Parties
Christina	Brusven	cbrusven@fredlaw.com	Fredrikson Byron	200 S 6th St Ste 4000 Minneapolis, MN 554021425	Electronic Service	No	SPL_SL_14-65_Interested Parties
Michael J.	Bull	mbull@mncee.org	Center for Energy and Environment	212 Third Ave N Ste 560 Minneapolis, MN 55401	Electronic Service	No	SPL_SL_14-65_Interested Parties
Jessica	Burdette	jessica.burdette@state.mn.us	Department of Commerce	85 7th Place East Suite 500 St. Paul, MN 55101	Electronic Service	No	SPL_SL_14-65_Interested Parties
Douglas M.	Carnival	dmc@mcgrannshea.com	McGrann Shea Carnival Straughn & Lamb	N/A	Electronic Service	No	SPL_SL_14-65_Interested Parties
Steve W.	Chriss	Stephen.chriss@walmart.com	Wal-Mart	2001 SE 10th St. Bentonville, AR 72716-5530	Electronic Service	No	SPL_SL_14-65_Interested Parties
Kenneth A.	Colburn	kcolburn@symbioticstrategies.com	Symbiotic Strategies, LLC	26 Winton Road Meredith, NH 32535413	Electronic Service	No	SPL_SL_14-65_Interested Parties

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1800 St. Paul, MN 55101	Electronic Service	Yes	SPL_SL_14-65_Interested Parties
George	Crocker	gwillc@nawo.org	North American Water Office	PO Box 174 Lake Elmo, MN 55042	Electronic Service	No	SPL_SL_14-65_Interested Parties
Carrie	Cullen Hitt	N/A	Solar Energy Industries Association	505 9th St. NW, Suite 800 Washington, DC 20004	Paper Service	No	SPL_SL_14-65_Interested Parties
David	Dahlberg	davedahlberg@nweco.com	Northwestern Wisconsin Electric Company	P.O. Box 9 104 South Pine Street Grantsburg, WI 548400009	Electronic Service	No	SPL_SL_14-65_Interested Parties
Lisa	Daniels	lisadaniels@windustry.org	Windustry	201 Ridgewood Ave Minneapolis, MN 55403	Electronic Service	No	SPL_SL_14-65_Interested Parties
Chris	Davis	christopher.davis@state.mn.us	Department of Commerce	Suite 280 85 Seventh Place East St. Paul, MN 551012198	Electronic Service	No	SPL_SL_14-65_Interested Parties
James	Denniston	james.r.denniston@xcelenergy.com	Xcel Energy Services, Inc.	414 Nicollet Mall, Fifth Floor Minneapolis, MN 55401	Electronic Service	No	SPL_SL_14-65_Interested Parties
Curt	Dieren	curt.dieren@dgr.com	L&O Power Cooperative	1302 S Union St Rock Rapids, IA 51246	Electronic Service	No	SPL_SL_14-65_Interested Parties
Ian	Dobson	residential.utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	Yes	SPL_SL_14-65_Interested Parties

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Brian	Draxten	bhdraxten@otpco.com	Otter Tail Power Company	P.O. Box 496 215 South Cascade Street Fergus Falls, MN 565380498	Electronic Service	No	SPL_SL_14-65_Interested Parties
Kristen	Eide Tollefson	healingsystems69@gmail.com	R-CURE	28477 N Lake Ave Frontenac, MN 55026-1044	Electronic Service	No	SPL_SL_14-65_Interested Parties
Rebecca	Eilers	rebecca.d.eilers@xcelenergy.com	Xcel Energy	414 Nicollet Mall - 401 7th Floor Minneapolis, MN 55401	Electronic Service	No	SPL_SL_14-65_Interested Parties
Betsy	Engelking	betsy@geronimoenergy.com	Geronimo Energy	7650 Edinborough Way Suite 725 Edina, MN 55435	Electronic Service	No	SPL_SL_14-65_Interested Parties
Oncu	Er	oncu.er@avantenergy.com	Avant Energy, Agent for MMPA	220 S. Sixth St. Ste. 1300 Minneapolis, MN 55402	Electronic Service	No	SPL_SL_14-65_Interested Parties
Rick	Evans	Rick.Evans@xcelenergy.com	Xcel Energy	404 Nicollet Mall Minneapolis, MN 55401	Electronic Service	No	SPL_SL_14-65_Interested Parties
John	Farrell	jfarrell@ilsr.org	Institute for Local Self-Reliance	1313 5th St SE #303 Minneapolis, MN 55414	Electronic Service	No	SPL_SL_14-65_Interested Parties
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 280 Saint Paul, MN 551012198	Electronic Service	No	SPL_SL_14-65_Interested Parties
Nathan	Franzen	nathan@geronimoenergy.com	Geronimo Energy	7650 Edinborough Way Suite 725 Edina, MN 55435	Electronic Service	No	SPL_SL_14-65_Interested Parties
Lee	Gabler	Lee.E.Gabler@xcelenergy.com	Xcel Energy	404 Nicollet Mall Minneapolis, MN 55401	Electronic Service	No	SPL_SL_14-65_Interested Parties

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Edward	Garvey	garveyed@aol.com	Residence	32 Lawton St Saint Paul, MN 55102	Electronic Service	No	SPL_SL_14-65_Interested Parties
Bruce	Gerhardson	bgerhardson@otpco.com	Otter Tail Power Company	PO Box 496 215 S Cascade St Fergus Falls, MN 565380496	Electronic Service	No	SPL_SL_14-65_Interested Parties
Timothy	Gulden	timothy.gulden@yahoo.com	Winona Renewable Energy, LLC	1449 Ridgewood Dr Winona, MN 55987	Electronic Service	No	SPL_SL_14-65_Interested Parties
Tony	Hainault	anthony.hainault@co.hennepin.mn.us	Hennepin County DES	701 4th Ave S Ste 700 Minneapolis, MN 55415-1842	Electronic Service	No	SPL_SL_14-65_Interested Parties
J Drake	Hamilton	hamilton@fresh-energy.org	Fresh Energy	408 St Peter St Saint Paul, MN 55101	Electronic Service	No	SPL_SL_14-65_Interested Parties
Jack	Hays	jack.hays@westwoodps.com	Westwood Professional Services	7699 Anagram Drive Eden Prairie, MN 55344	Electronic Service	No	SPL_SL_14-65_Interested Parties
Brandon	Heath	bheath@misoenergy.org	MISO Energy	2985 Ames Crossing Rd Eagan, MN 55121	Electronic Service	No	SPL_SL_14-65_Interested Parties
Kimberly	Hellwig	kimberly.hellwig@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	SPL_SL_14-65_Interested Parties
Jared	Hendricks	hendricksj@owatonnautilities.com	Owatonna Public Utilities	PO Box 800 208 S Walnut Ave Owatonna, MN 55060-2940	Electronic Service	No	SPL_SL_14-65_Interested Parties
Annete	Henkel	mui@mnutilityinvestors.org	Minnesota Utility Investors	413 Wacouta Street #230 St.Paul, MN 55101	Electronic Service	No	SPL_SL_14-65_Interested Parties

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Holly	Hinman	holly.r.hinman@xcelenergy.com	Xcel Energy	414 Nicollet Mall, 7th Floor Minneapolis, MN 55401	Electronic Service	No	SPL_SL_14-65_Interested Parties
Michael	Hoppe	il23@mtn.org	Local Union 23, I.B.E.W.	932 Payne Avenue St. Paul, MN 55130	Electronic Service	No	SPL_SL_14-65_Interested Parties
David	Horneck	david.g.horneck@xcelenergy.com	Xcel Energy	1800 Larimer Street Denver, CO 80202	Electronic Service	No	SPL_SL_14-65_Interested Parties
Jan	Hubbard	jan.hubbard@comcast.net		7730 Mississippi Lane Brooklyn Park, MN 55444	Electronic Service	No	SPL_SL_14-65_Interested Parties
Matt	Hughes	N/A	Cooperative Network	145 University Ave W, Ste 450 St. Paul, MN 55103-7044	Paper Service	No	SPL_SL_14-65_Interested Parties
Steve	Huso	steve.huso@xcelenergy.com	Xcel Energy	G.O. 7th Floor 414 Nicollet Mall Minneapolis, MN 554011993	Electronic Service	No	SPL_SL_14-65_Interested Parties
Michael	Jacobs	mjacobs@ucsusa.org	Union of Concerned Scientists	2 Brattle Square Cambridge, MA 02138	Electronic Service	No	SPL_SL_14-65_Interested Parties
Casey	Jacobson	cjacobson@bepc.com	Basin Electric Power Cooperative	1717 East Interstate Avenue Bismarck, ND 58501	Electronic Service	No	SPL_SL_14-65_Interested Parties
Dwight	Jelle	dkjelle@gmail.com	Best Power International, LLC	P.O. 5126 Hopkins, MN 55343	Electronic Service	No	SPL_SL_14-65_Interested Parties

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Alan	Jenkins	aj@jenkinsatlaw.com	Jenkins at Law	2265 Roswell Road Suite 100 Marietta, GA 30062	Electronic Service	No	SPL_SL_14-65_Interested Parties
Linda	Jensen	linda.s.jensen@ag.state.mn.us	Office of the Attorney General-DOC	1800 BRM Tower 445 Minnesota Street St. Paul, MN 551012134	Electronic Service	No	SPL_SL_14-65_Interested Parties
Richard	Johnson	Rick.Johnson@lawmoss.com	Moss & Barnett	150 S. 5th Street Suite 1200 Minneapolis, MN 55402	Electronic Service	No	SPL_SL_14-65_Interested Parties
Nate	Jones	njones@hcpd.com	Heartland Consumers Power	PO Box 248 Madison, SD 57042	Electronic Service	No	SPL_SL_14-65_Interested Parties
Michael	Kampmeyer	mkampmeyer@a-e-group.com	AEG Group, LLC	260 Salem Church Road Sunfish Lake, Minnesota 55118	Electronic Service	No	SPL_SL_14-65_Interested Parties
Mark J.	Kaufman	mkaufman@ibewlocal949.org	IBEW Local Union 949	12908 Nicollet Avenue South Burnsville, MN 55337	Electronic Service	No	SPL_SL_14-65_Interested Parties
Julie	Ketchum	N/A	Waste Management	20520 Keokuk Ave Ste 200 Lakeville, MN 55044	Paper Service	No	SPL_SL_14-65_Interested Parties
Brad	Klein	bklein@elpc.org	Environmental Law & Policy Center	35 E. Wacker Drive, Suite 1600 Suite 1600 Chicago, IL 60601	Electronic Service	No	SPL_SL_14-65_Interested Parties
Kerry	Klemm	kerry.r.klemm@xcelenergy.com	Xcel Energy Services, Inc	414 Nicollet Mall Minneapolis, MN 55401	Electronic Service	No	SPL_SL_14-65_Interested Parties

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Thomas	Koehler	TGK@IBEW160.org	Local Union #160, IBEW	2909 Anthony Ln St Anthony Village, MN 55418-3238	Electronic Service	No	SPL_SL_14-65_Interested Parties
Chris	Kopel	chrisk@CMPASgroup.org	Central Minnesota Municipal Power Agency	459 S Grove St Blue Earth, MN 56013-2629	Electronic Service	No	SPL_SL_14-65_Interested Parties
Jon	Kramer	sundialjon@gmail.com	Sundial Solar	3209 W 76th St Edina, MN 55435	Electronic Service	No	SPL_SL_14-65_Interested Parties
Michael	Krikava	mkrikava@briggs.com	Briggs And Morgan, P.A.	2200 IDS Center 80 S 8th St Minneapolis, MN 55402	Electronic Service	No	SPL_SL_14-65_Interested Parties
Allen	Krug	allen.krug@xcelenergy.com	Xcel Energy	414 Nicollet Mall-7th fl Minneapolis, MN 55401	Electronic Service	No	SPL_SL_14-65_Interested Parties
Scott	Kurtz	Scott.J.Kurtz@xcelenergy.com	Xcel Energy	825 Rice Street St. Paul, MN 55117	Electronic Service	No	SPL_SL_14-65_Interested Parties
Douglas	Larson	dlarson@dakotaelectric.com	Dakota Electric Association	4300 220th St W Farmington, MN 55024	Electronic Service	No	SPL_SL_14-65_Interested Parties
Amy	Liberkowski	amy.a.liberkowski@xcelenergy.com	Xcel Energy	414 Nicollet Mall 7th Floor Minneapolis, MN 554011993	Electronic Service	No	SPL_SL_14-65_Interested Parties
Tim	Lindl	tlindl@kfwlaw.com	Keyes, Fox & Wiedman LLP	436 14th St, Ste 1305 Oakland, CA 94612	Electronic Service	No	SPL_SL_14-65_Interested Parties
Bob	Long	rlong@larkinhoffman.com	Larkin Hoffman (Silicon Energy)	1500 Wells Fargo Plaza 7900 Xerxes Ave S Bloomington, MN 55431	Electronic Service	No	SPL_SL_14-65_Interested Parties

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Susan	Mackenzie	susan.mackenzie@state.mn.us	Public Utilities Commission	121 7th Place E Ste 350 St. Paul, MN 551012147	Electronic Service	No	SPL_SL_14-65_Interested Parties
Kavita	Maini	kmaini@wi.rr.com	KM Energy Consulting LLC	961 N Lost Woods Rd Oconomowoc, WI 53066	Electronic Service	No	SPL_SL_14-65_Interested Parties
Pam	Marshall	pam@energycents.org	Energy CENTS Coalition	823 7th St E St. Paul, MN 55106	Electronic Service	No	SPL_SL_14-65_Interested Parties
Jennifer	Martin	N/A	Center for Resource Solutions	1012 Torney Ave, 2nd Floor San Francisco, CA 94129	Paper Service	No	SPL_SL_14-65_Interested Parties
Mary	Martinka	mary.a.martinka@xcelenergy.com	Xcel Energy Inc	414 Nicollet Mall 7th Floor Minneapolis, MN 55401	Electronic Service	No	SPL_SL_14-65_Interested Parties
Natalie	McIntire	natalie.mcintire@gmail.com	Wind on the Wires	570 Asbury St Ste 201 Saint Paul, MN 55104-1850	Electronic Service	No	SPL_SL_14-65_Interested Parties
Dave	McNary	David.McNary@hennepin.us	Hennepin County DES	701 Fourth Ave S Ste 700 Minneapolis, MN 55415-1842	Electronic Service	No	SPL_SL_14-65_Interested Parties
John	McWilliams	John.McWilliams@DairylandPower.com	Dairyland Power Cooperative	3200 East Ave SPO Box 817 La Crosse, WI 54601-7227	Electronic Service	No	SPL_SL_14-65_Interested Parties
Herbert	Minke	hminke@allete.com	Minnesota Power	30 W Superior St Duluth, MN 55802	Electronic Service	No	SPL_SL_14-65_Interested Parties

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
David	Moeller	dmoeller@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022093	Electronic Service	No	SPL_SL_14-65_Interested Parties
Dalene	Monsebroten	dalene.monsebroten@nmpagency.com	Northern Municipal Power Agency	123 2nd St W Thief River Falls, MN 56701	Electronic Service	No	SPL_SL_14-65_Interested Parties
Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP	33 South Sixth St Ste 4200 Minneapolis, MN 55402	Electronic Service	No	SPL_SL_14-65_Interested Parties
Ben	Nelson	benn@cmpasgroup.org	CMMPA	459 South Grove Street Blue Earth, MN 56013	Electronic Service	No	SPL_SL_14-65_Interested Parties
Dale	Niezwaag	dniezwaag@bepc.com	Basin Electric Power Cooperative	1717 East Interstate Avenue Bismarck, ND 58503	Electronic Service	No	SPL_SL_14-65_Interested Parties
David	Niles	david.niles@avantenergy.com	Minnesota Municipal Power Agency	220 South Sixth Street Suite 1300 Minneapolis, Minnesota 55402	Electronic Service	No	SPL_SL_14-65_Interested Parties
Michael	Noble	noble@fresh-energy.org	Fresh Energy	Hamm Bldg., Suite 220 408 St. Peter Street St. Paul, MN 55102	Electronic Service	No	SPL_SL_14-65_Interested Parties
Rolf	Nordstrom	rnordstrom@gpisd.net	Great Plains Institute	2801 21ST AVE S STE 220 Minneapolis, MN 55407-1229	Electronic Service	No	SPL_SL_14-65_Interested Parties
Samantha	Norris	samanthanorris@alliantenergy.com	Interstate Power and Light Company	200 1st Street SE PO Box 351 Cedar Rapids, IA 524060351	Electronic Service	No	SPL_SL_14-65_Interested Parties

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Kate	O'Connell	kate.oconnell@state.mn.us	Department of Commerce	Suite 50085 Seventh Place East St. Paul, MN 551012198	Electronic Service	No	SPL_SL_14-65_Interested Parties
Russell	Olson	rolson@hcpd.com	Heartland Consumers Power District	PO Box 248 Madison, SD 570420248	Electronic Service	No	SPL_SL_14-65_Interested Parties
Nick	Paluck	nick.paluck@xcelenergy.com	Xcel Energy	7th Floor 414 Nicollet Mall Minneapolis, MN 554011993	Electronic Service	No	SPL_SL_14-65_Interested Parties
James	Pearson	james.g.pearson@xcelenergy.com	Xcel Energy	414 Nicollet Mall Minneapolis, MN 55401	Electronic Service	No	SPL_SL_14-65_Interested Parties
Joyce	Peppin	joyce@mrea.org	Minnesota Rural Electric Association	11640 73rd Ave N Maple Grove, MN 55369	Electronic Service	No	SPL_SL_14-65_Interested Parties
Mary Beth	Peranteau	mperanteau@wheelerlaw.com	Wheeler Van Sickle & Anderson SC	44 E. Mifflin Street, 10th Floor Madison, WI 53703	Electronic Service	No	SPL_SL_14-65_Interested Parties
Donna	Pickard	dpickardgsss@gmail.com	Genie Solar Support Services	1215 Lilac Lane Excelsior, MN 55331	Electronic Service	No	SPL_SL_14-65_Interested Parties
Marcia	Podratz	mpodratz@mnpower.com	Minnesota Power	30 W Superior S Duluth, MN 55802	Electronic Service	No	SPL_SL_14-65_Interested Parties
Mark	Rathbun	mrathbun@grenergy.com	Great River Energy	12300 Elm Creek Blvd Maple Grove, MN 55369	Electronic Service	No	SPL_SL_14-65_Interested Parties

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Michael	Reinertson	michael.reinertson@avantenergy.com	Avant Energy	220 S. Sixth St. Ste 1300 Minneapolis, Minnesota 55402	Electronic Service	No	SPL_SL_14-65_Interested Parties
John C.	Reinhardt		Laura A. Reinhardt	3552 26Th Avenue South Minneapolis, MN 55406	Paper Service	No	SPL_SL_14-65_Interested Parties
Kevin	Reuther	kreuther@mncenter.org	MN Center for Environmental Advocacy	26 E Exchange St, Ste 206 St. Paul, MN 551011667	Electronic Service	No	SPL_SL_14-65_Interested Parties
Enio	Ricci	ericci@invenergyllc.com	Invenergy LLC	17830 New Hampshire Ave Ste 300 Ashton, MD 20861	Paper Service	No	SPL_SL_14-65_Interested Parties
Robert K.	Sahr	bsahr@eastriver.coop	East River Electric Power Cooperative	P.O. Box 227 Madison, SD 57042	Electronic Service	No	SPL_SL_14-65_Interested Parties
Richard	Savelkoul	rsavelkoul@martinsquires.com	Martin & Squires, P.A.	332 Minnesota Street Ste W2750 St. Paul, MN 55101	Electronic Service	No	SPL_SL_14-65_Interested Parties
Larry L.	Schedin	Larry@LLSResources.com	LLS Resources, LLC	332 Minnesota St, Ste W1390 St. Paul, MN 55101	Electronic Service	No	SPL_SL_14-65_Interested Parties
Christopher	Schoenherr	cp.schoenherr@smmpa.org	SMMPA	500 First Ave SW Rochester, MN 55902-3303	Electronic Service	No	SPL_SL_14-65_Interested Parties
Kay	Schraeder	kschraeder@minnkota.com	Minnkota Power	5301 32nd Ave S Grand Forks, ND 58201	Electronic Service	No	SPL_SL_14-65_Interested Parties

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Kevin	Schwain	Kevin.D.Schwain@xcelenergy.com	Xcel Energy	404 Nicollet Mall Minneapolis, MN 55401	Electronic Service	No	SPL_SL_14-65_Interested Parties
Dean	Sedgwick	Sedgwick@Itascapower.com	Itasca Power Company	PO Box 455 Spring Lake, MN 56680	Electronic Service	No	SPL_SL_14-65_Interested Parties
Janet	Shaddix Elling	jshaddix@janetshaddix.com	Shaddix And Associates	7400 Lyndale Ave S Ste 190 Richfield, MN 55423	Electronic Service	No	SPL_SL_14-65_Interested Parties
David	Shaffer	shaff081@gmail.com	Minnesota Solar Energy Industries Project	1005 Fairmount Ave Saint Paul, MN 55105	Electronic Service	No	SPL_SL_14-65_Interested Parties
Gary	Shaver	gshaver@silicon-energy.com	Silicon Energy	3506 124th St NE Marysville, WA 98271	Electronic Service	No	SPL_SL_14-65_Interested Parties
Erin	Shea	eshea@silicon-energy.com	Silicon Energy	PO Box 376 8787 Silicon Way Mt Iron, MN 55768	Electronic Service	No	SPL_SL_14-65_Interested Parties
Doug	Shoemaker	dougs@charter.net	Minnesota Renewable Energy	2928 5th Ave S Minneapolis, MN 55408	Electronic Service	No	SPL_SL_14-65_Interested Parties
Ken	Smith	ken.smith@districtenergy.com	District Energy St. Paul Inc.	76 W Kellogg Blvd St. Paul, MN 55102	Electronic Service	No	SPL_SL_14-65_Interested Parties
Trevor	Smith	trevor.smith@avantenergy.com	Avant Energy, Inc.	220 South Sixth Street Suite 1300 Minneapolis, Minnesota 55402	Electronic Service	No	SPL_SL_14-65_Interested Parties
Joshua	Smith	joshua.smith@sierraclub.org		85 Second St FL 2 San Francisco, California 94105	Electronic Service	No	SPL_SL_14-65_Interested Parties

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Beth H.	Soholt	bsoholt@windonthewires.org	Wind on the Wires	570 Asbury Street Suite 201 St. Paul, MN 55104	Electronic Service	No	SPL_SL_14-65_Interested Parties
Russ	Stark	Russ.Stark@ci.stpaul.mn.us	City of St. Paul	390 City Hall 15 West Kellogg Boulevard Saint Paul, MN 55102	Electronic Service	No	SPL_SL_14-65_Interested Parties
Byron E.	Starns	byron.starns@stinson.com	STINSON LLP	50 S 6th St Ste 2600 Minneapolis, MN 55402	Electronic Service	No	SPL_SL_14-65_Interested Parties
James M	Strommen	jstrommen@kennedy-graven.com	Kennedy & Graven, Chartered	200 S 6th St Ste 470 Minneapolis, MN 55402	Electronic Service	No	SPL_SL_14-65_Interested Parties
Eric	Swanson	eswanson@winthrop.com	Winthrop & Weinstine	225 S 6th St Ste 3500 Capella Tower Minneapolis, MN 554024629	Electronic Service	No	SPL_SL_14-65_Interested Parties
Thomas P.	Sweeney III	tom.sweeney@easycleanenergy.com	Clean Energy Collective	P O Box 1828 Boulder, CO 80306-1828	Electronic Service	No	SPL_SL_14-65_Interested Parties
Lynnette	Sweet	Regulatory.records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	No	SPL_SL_14-65_Interested Parties
Pat	Treseler	pat.jcplaw@comcast.net	Paulson Law Office LTD	4445 W 77th Street Suite 224 Edina, MN 55435	Electronic Service	No	SPL_SL_14-65_Interested Parties
Lise	Trudeau	lise.trudeau@state.mn.us	Department of Commerce	85 7th Place East Suite 500 Saint Paul, MN 55101	Electronic Service	No	SPL_SL_14-65_Interested Parties

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Lisa	Veith	lisa.veith@ci.stpaul.mn.us	City of St. Paul	400 City Hall and Courthouse 15 West Kellogg Blvd. St. Paul, MN 55102	Electronic Service	No	SPL_SL_14-65_Interested Parties
Gracie	Walovich	gracie@allianceforsolarchoice.com	The Alliance for Solar Choice	595 Market St FL 29 San Francisco, CA 94105	Electronic Service	No	SPL_SL_14-65_Interested Parties
Roger	Warehime	warehimer@owatonnautilities.com	Owatonna Public Utilities	208 South WalnutPO Box 800 Owatonna, MN 55060	Electronic Service	No	SPL_SL_14-65_Interested Parties
Paul	White	paul.white@prcwind.com	Project Resources Corp./Tamarac Line LLC/Ridgewind	618 2nd Ave SE Minneapolis, MN 55414	Electronic Service	No	SPL_SL_14-65_Interested Parties
Scott M.	Wilensky	scott.wilensky@xcelenergy.com	Xcel Energy	7th Floor 414 Nicollet Mall Minneapolis, MN 554011993	Electronic Service	No	SPL_SL_14-65_Interested Parties
Steven	Wishart	steven.w.wishart@xcelenergy.com	Xcel Energy	7th Floor 414 Nicollet Mall Minneapolis, MN 554011993	Electronic Service	No	SPL_SL_14-65_Interested Parties
Robyn	Woeste	robynwoeste@alliantenergy.com	Interstate Power and Light Company	200 First St SE Cedar Rapids, IA 52401	Electronic Service	No	SPL_SL_14-65_Interested Parties
Daniel P	Wolf	dan.wolf@state.mn.us	Public Utilities Commission	121 7th Place East Suite 350 St. Paul, MN 551012147	Electronic Service	Yes	SPL_SL_14-65_Interested Parties
Thomas J.	Zaremba	TZaremba@wheelerlaw.com	WHEELER, VAN SICKLE & ANDERSON	44 E. Mifflin Street, 10th Floor Madison, WI 53703	Electronic Service	No	SPL_SL_14-65_Interested Parties

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Ross	Abbey	ross.abbey@us-solar.com	United States Solar Corp.	100 North 6th St Ste 222C Minneapolis, MN 55403	Electronic Service	No	OFF_SL_13-867_Official
Michael	Allen	michael.allen@allenergysolar.com	All Energy Solar	721 W 26th st Suite 211 Minneapolis, Minnesota 55405	Electronic Service	No	OFF_SL_13-867_Official
David	Amster Olzweski	david@mysunshare.com	SunShare, LLC	1151 Bannock St Denver, CO 80204-8020	Electronic Service	No	OFF_SL_13-867_Official
Sara	Baldwin Auck	sarab@irecusa.org	Interstate Renewable Energy Council, Inc.	PO Box 1156 Latham, NY 12110	Electronic Service	No	OFF_SL_13-867_Official
Laura	Beaton	beaton@smwlaw.com	Shute, Mihaly & Weinberger LLP	396 Hayes Street San Francisco, CA 94102	Electronic Service	No	OFF_SL_13-867_Official
Kenneth	Bradley	kbradley1965@gmail.com		2837 Emerson Ave S Apt CW112 Minneapolis, MN 55408	Electronic Service	No	OFF_SL_13-867_Official
Michael J.	Bull	mbull@mncee.org	Center for Energy and Environment	212 Third Ave N Ste 560 Minneapolis, MN 55401	Electronic Service	No	OFF_SL_13-867_Official
Jessica	Burdette	jessica.burdette@state.mn.us	Department of Commerce	85 7th Place East Suite 500 St. Paul, MN 55101	Electronic Service	No	OFF_SL_13-867_Official
Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1800 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_13-867_Official
Arthur	Crowell	Crowell.arthur@yahoo.com	A Work of Art Solar	14333 Orchard Rd. Minnetonka, MN 55345	Electronic Service	No	OFF_SL_13-867_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Timothy	DenHerder Thomas	timothy@cooperativeenergyfutures.com	Cooperative Energy Futures	3500 Bloomington Ave. S Minneapolis, MN 55407	Electronic Service	No	OFF_SL_13-867_Official
James	Denniston	james.r.denniston@xcelenergy.com	Xcel Energy Services, Inc.	414 Nicollet Mall, Fifth Floor Minneapolis, MN 55401	Electronic Service	No	OFF_SL_13-867_Official
Ian	Dobson	residential.utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	Yes	OFF_SL_13-867_Official
Jason	Edens	jason@rreal.org	Rural Renewable Energy Alliance	3963 8th Street SW Backus, MN 55435	Electronic Service	No	OFF_SL_13-867_Official
Betsy	Engelking	betsy@geronimoenergy.com	Geronimo Energy	7650 Edinborough Way Suite 725 Edina, MN 55435	Electronic Service	No	OFF_SL_13-867_Official
John	Farrell	jfarrell@ilsr.org	Institute for Local Self-Reliance	1313 5th St SE #303 Minneapolis, MN 55414	Electronic Service	No	OFF_SL_13-867_Official
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 280 Saint Paul, MN 551012198	Electronic Service	No	OFF_SL_13-867_Official
Matthew D.	Forsgren	mforsgren@greeneespel.com	GREENE ESPEL PLLP	222 S. Ninth Street, Suite 2200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_13-867_Official
Nathan	Franzen	nathan@geronimoenergy.com	Geronimo Energy	7650 Edinborough Way Suite 725 Edina, MN 55435	Electronic Service	No	OFF_SL_13-867_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Hal	Galvin	halgalvin@comcast.net	Provectus Energy Development llc	1936 Kenwood Parkway Minneapolis, MN 55405	Electronic Service	No	OFF_SL_13-867_Official
Allen	Gleckner	gleckner@fresh-energy.org	Fresh Energy	408 St. Peter Street Ste 220 Saint Paul, Minnesota 55102	Electronic Service	No	OFF_SL_13-867_Official
Sean	Gosiewski	sean@afors.org	Alliance for Sustainability	2801 21st Ave S Ste 100 Minneapolis, MN 55407	Electronic Service	No	OFF_SL_13-867_Official
Todd J.	Guerrero	todd.guerrero@kutakrock.com	Kutak Rock LLP	Suite 1750 220 South Sixth Street Minneapolis, MN 554021425	Electronic Service	No	OFF_SL_13-867_Official
Timothy	Gulden	timothy.gulden@yahoo.com	Winona Renewable Energy, LLC	1449 Ridgewood Dr Winona, MN 55987	Electronic Service	No	OFF_SL_13-867_Official
Kimberly	Hellwig	kimberly.hellwig@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_13-867_Official
Jan	Hubbard	jan.hubbard@comcast.net		7730 Mississippi Lane Brooklyn Park, MN 55444	Electronic Service	No	OFF_SL_13-867_Official
John S.	Jaffray	jjaffray@jjrpower.com	JJR Power	350 Highway 7 Suite 236 Excelsior, MN 55331	Electronic Service	No	OFF_SL_13-867_Official
Linda	Jensen	linda.s.jensen@ag.state.mn.us	Office of the Attorney General-DOC	1800 BRM Tower 445 Minnesota Street St. Paul, MN 551012134	Electronic Service	No	OFF_SL_13-867_Official
Julie	Jorgensen	juliejorgensen@greenmarksolar.com	Greenmark Solar	4630 Quebec Ave N New Hope, MN 55428-4973	Electronic Service	No	OFF_SL_13-867_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Ralph	Kaehler	ralph.kaehler@novelenergy.biz		N/A	Electronic Service	No	OFF_SL_13-867_Official
Michael	Kampmeyer	mkampmeyer@a-e-group.com	AEG Group, LLC	260 Salem Church Road Sunfish Lake, Minnesota 55118	Electronic Service	No	OFF_SL_13-867_Official
Brad	Klein	bklein@elpc.org	Environmental Law & Policy Center	35 E. Wacker Drive, Suite 1600 Suite 1600 Chicago, IL 60601	Electronic Service	No	OFF_SL_13-867_Official
Aaron	Knoll	aknoll@greeneespel.com	Greene Espel PLLP	222 South Ninth Street Suite 2200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_13-867_Official
Jon	Kramer	sundialjon@gmail.com	Sundial Solar	3209 W 76th St Edina, MN 55435	Electronic Service	No	OFF_SL_13-867_Official
Michael	Krause	michaelkrause61@yahoo.com	Kandiyo Consulting, LLC	433 S 7th Street Suite 2025 Minneapolis, Minnesota 55415	Electronic Service	No	OFF_SL_13-867_Official
Dean	Leischow	dean@sunrisenrg.com	Sunrise Energy Ventures	315 Manitoba Ave Wayzata, MN 55391	Electronic Service	No	OFF_SL_13-867_Official
Thomas	Melone	Thomas.Melone@AllcoUS.com	Minnesota Go Solar LLC	222 South 9th Street Suite 1600 Minneapolis, Minnesota 55120	Electronic Service	No	OFF_SL_13-867_Official
Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP	33 South Sixth St Ste 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_13-867_Official
Rolf	Nordstrom	rnordstrom@gpisd.net	Great Plains Institute	2801 21ST AVE S STE 220 Minneapolis, MN 55407-1229	Electronic Service	No	OFF_SL_13-867_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Jeff	O'Neill	jeff.oneill@ci.monticello.mn.us	City of Monticello	505 Walnut Street Suite 1 Monticelllo, Minnesota 55362	Electronic Service	No	OFF_SL_13-867_Official
Eric	Pasi	ericp@ips-solar.com	IPS Solar	2670 Patton Rd Roseville, MN 55113	Electronic Service	No	OFF_SL_13-867_Official
Dan	Patry	dpatry@sunedison.com	SunEdison	600 Clipper Drive Belmont, CA 94002	Electronic Service	No	OFF_SL_13-867_Official
Jeffrey C	Paulson	jeff.jcplaw@comcast.net	Paulson Law Office, Ltd.	4445 W 77th Street Suite 224 Edina, MN 55435	Electronic Service	No	OFF_SL_13-867_Official
Joyce	Peppin	joyce@mrea.org	Minnesota Rural Electric Association	11640 73rd Ave N Maple Grove, MN 55369	Electronic Service	No	OFF_SL_13-867_Official
David	Shaffer	shaff081@gmail.com	Minnesota Solar Energy Industries Project	1005 Fairmount Ave Saint Paul, MN 55105	Electronic Service	No	OFF_SL_13-867_Official
Doug	Shoemaker	dougs@charter.net	Minnesota Renewable Energy	2928 5th Ave S Minneapolis, MN 55408	Electronic Service	No	OFF_SL_13-867_Official
Eric	Swanson	eswanson@winthrop.com	Winthrop & Weinstine	225 S 6th St Ste 3500 Capella Tower Minneapolis, MN 554024629	Electronic Service	No	OFF_SL_13-867_Official
Thomas P.	Sweeney III	tom.sweeney@easycleanenergy.com	Clean Energy Collective	P O Box 1828 Boulder, CO 80306-1828	Electronic Service	No	OFF_SL_13-867_Official
Lynnette	Sweet	Regulatory.records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	No	OFF_SL_13-867_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Anna	Tobin	atobin@greeneespel.com	Greene Espel PLLP	222 South Ninth Street Suite 2200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_13-867_Official
Pat	Treseler	pat.jcplaw@comcast.net	Paulson Law Office LTD	4445 W 77th Street Suite 224 Edina, MN 55435	Electronic Service	No	OFF_SL_13-867_Official
Daniel P	Wolf	dan.wolf@state.mn.us	Public Utilities Commission	121 7th Place East Suite 350 St. Paul, MN 551012147	Electronic Service	Yes	OFF_SL_13-867_Official