Minnesota Public Utilities Commission
Staff Briefing Papers

Meeting Date: March 12, 2014 ....**Agenda Item **#3**

Company: All Rate Regulated Electric Utilities

Docket No. **E-999/M-14-65**

In the Matter of Establishing a Distributed Solar Value Methodology under Minn. Stat. §216B.164, subd. 10 (e) and (f)

Issue: Should the Commission approve the Distributed Solar Value Methodology proposed by the Department of Commerce (DOC) pursuant to Minn. Stat. §216B.164, subd. 10 (e) and (f)?

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Relevant Documents

DOC Value of Solar Filing, Comments. .... January 31, 2014
DOC Value of Solar Methodology. .... January 31, 2014
Minnesota Power, Initial Comments.. February 13, 2014
Xcel Energy, Initial Comments.. .February 13, 2014
The Alliance for Solar Choice, Initial Comments .... February 13, 2014
Environmental Law and Policy Center, et al, Initial Comments .... February 13, 2014
Minnesota Rural Electric Association, Initial Comments.................................. February 13, 2014
MN Solar Energy Industries Association, Initial Comments............................. .February 13, 2014
Union of Concerned Scientists, Reply Comments... February 19, 2014
Solar Energy Industries Association, Comments.. February 19, 2014
Minnesota Renewable Energy Society, Reply Comments. .... February 20, 2014
Solar Energy Industries Association, Reply Comments. .... February 20, 2014
Xcel Energy, Reply Comments.. February 20, 2014
Environmental Law and Policy Center, et al, Reply Comments .... February 20, 2014
Minnesota Power, Reply Comments... February 20, 2014
The Alliance for Solar Choice, Reply Comments .... February 20, 2014
Otter Tail Power Company, Reply Comments. .... February 20, 2014
DOC, Reply Comments. .... February 20, 2014
Cooperative Network, Comments... February 21, 2014

Center for Resource Solutions, Comments .... February 24, 2014

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Statement of the issue

Should the Commission approve the Distributed Solar Value Methodology proposed by the Department of Commerce (DOC) pursuant to Minn. Stat. §216B.164, subd. 10 (e) and (f)?

Background

Legislation passed in 2013 requires the Department to file a Distributed Solar Value methodology with the Minnesota Public Utilities Commission (Commission) by January 31, 2014. The Commission must approve, modify with the Department's consent, or disapprove the methodology within 60 days (by March 31, 2014).[1]

Under Minn. Stat. §216B.164, subd. 10 (a) - (d), a public utility may apply for Commission approval of an alternative tariff that applies the distributed solar value methodology established by the Department and approved by the Commission, and that meets other listed statutory requirements. There will also be policy, technical, and implementation issues related to developing specific utility tariffs that will be addressed at a later time.

The new statute contains some provisions that are different from many of the statutes in Chapter 216B:

- The Department proposes the methodology, and the Commission may only modify the methodology if the Department consents (otherwise, the Commission may approve the methodology as submitted, or reject the methodology).

- Utilities are not required to adopt a Value of Solar tariff; they may propose one at their option.

- If a Value of Solar (VOS) tariff is adopted by a utility and approved by the Commission, the owner of a PV device receiving a Value of Solar rate must be paid the same kWh rate generated each year for the term of the contract. (Annual updates are required to be made, but those updates would apply to owners of PV devices that enter into the contract in the year in which the update is made.)

- The VOS tariff is an alternative to existing Net Energy Metering (NEM) tariffs that currently compensate home and business owners who own PV systems for their electricity production.

The issues before the Commission relate to the VOS methodology under Minn. Stat. §216B.164, Subdivision 10, paragraphs (e) and (f). Subdivision 10 (e) requires the Commission to approve,

[1] See Minn. Stat. §216B.164, subd. 10, Alternative tariff; compensation for resource value. The statute refers to an "alternative tariff" that uses this methodology that most commenters refer to as a Value of Solar Tariff (VOST).

modify or disapprove a DOC proposed VOS Methodology within 60 days, and Subdivision 10 (f) outlines the requirements that the DOC's proposed VOS Methodology must meet. Other portions of Minn. Stat. §216B.164, Subdivision 10, relate to VOS tariff issues. The Commission's January 31, 2014 notice soliciting comments specifically directed that comments be limited to issues related to methodology in paragraphs (e) and (f).

Several comments raise concerns that go to tariff issues, such as the effect on existing net-metered customers, PURPA compliance, and tax consequences. While these briefing papers provide a brief discussion of these issues, staff recommends that the Commission not make formal decisions on these matters. These issues are outside the scope of the Notice and therefore may not have been addressed by entities who may be interested in the issues. The Commission can wait to address these and other tariff issues when a utility files a VOS tariff, or could direct staff to establish a new docket in which they could be addressed.

Department Value of Solar (VOS) Methodology: Framework and Approach

The Department filed its proposed VOS Methodology with the Commission on January 31, 2014.[2] It made three modifications to its proposed Methodology in reply comments.

Subdivision 10 (e) requires that, in developing the VOS Methodology, the DOC "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."

Given the requirements of Subdivision 10 (e), the DOC's selection of cost components included in the VOS rate calculation is based on requirements and guidance in the enabling statute, 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.[3] Stakeholders participated in four public workshops and provided comments through workshop panels, workshop Q&A sessions and written comments.[4]

The DOC Methodology is designed to estimate the marginal value of distributed solar PV resources to "the utility, its customers and society."[5] The alternative tariff is not a direct incentive for distributed PV, nor is it intended to eliminate the need for current or future solar incentive programs. The intent of the tariff is to arrive at a value for distributed solar generation.

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[2] See the DOC's "Minnesota Value of Solar: Methodology," filed January 31, 2014, in the current docket.

[3] See "Summary of Stakeholder Engagement," DOC filing, January 31, 2014, pp. 5-6, and Appendix to the filing.

[4] All comments filed in the DOC process as well as stakeholder presentations and other material are available at: http://mn.gov/commerce/energy/topics/resources/energy-legislation-initiatives/value-of-solar-tariff-methodology%20.jsp

[5] Minn. Stat. §216B.164, subd. 10 (a).

The statute specifically requires in Subdivision 10 (f) that the distributed solar value Methodology must, at a minimum, account for:

- the value of the (solar) energy and its delivery
- generation capacity
- transmission capacity
- transmission & distribution line losses
- environmental value

Further, the Department may, based on "known and measurable evidence of the cost or benefit of solar operation to the utility, incorporate other values into the Methodology," including:

- credit for locally manufactured or assembled energy systems
- credit for systems installed in high-value locations on the distribution grid, and/or
- other factors

The Methodology proceeds in a series of steps. When completed, these steps are integrated in a final, utility-specific, valuation which adheres to the statute. Its components are each constructed separately but may affect one another.[6] The first step is to identify the categories of marginal costs that are avoided when a solar PV unit is installed. There are eight categories of avoided costs. Definitions of each are provided in the DOC Methodology Glossary (see Table 19, pp. 45-48). Each is converted to a 25 year levelized present value as required by statute [Subdivision 10, paragraph (g)]. The eight categories or components are:

- Avoided Fuel Cost
- Avoided Plant O&M - Fixed
- Avoided Plant O&M - Variable
- Avoided Generation Capacity Cost
- Avoided Reserve Capacity Cost
- Avoided Transmission Capacity Cost
- Avoided Distribution Capacity Cost
- Avoided Environmental Cost

Avoided Voltage Control Cost and Solar Integration Cost are kept as "placeholder" components for future years. Methodologies for calculating these placeholder cost components are not provided, but may be developed in the future.[7]

[6] For example, to change the marginal unit upon which the avoided capacity cost is based will require a change in the avoided fuel cost calculation; changes in avoided fuel cost assumptions could increase/decrease avoided environmental costs.

[7] Voltage control benefits are anticipated but will first require implementation of recent change in interconnection standards. Solar integration costs are expected to be small, but possibly measureable, and further research is required.

The DOC selected and defined the VOS components based on the following considerations:

- Environmental costs are included as a required component, and are based on existing Minnesota and federal EPA 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.

Two tables resulting from the Methodology facilitate stakeholder understanding of the process of arriving at a VOS rate (also referred to as a tariff or credit): (1) the VOS Data Table (a table of utility-specific input assumptions),[8] and (2) the VOS Calculation Table (a table of utility-specific total value of solar).[9] Together these two tables are intended to promote stakeholder understanding and transparency. The Methodology is intended to be transferable and capable of being replicated by regulators, utilities, and stakeholders. The VOS Calculation Table below illustrates the list of avoided costs weighted by characteristics specific to the utility.

VOS Calculation Table: economic value, load match, distributed loss savings and distributed PV value (corrected and revised)

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									
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[8] See Table 5, DOC's "Minnesota Value of Solar: Methodology," p. 12.

[9] See Figure 1, DOC's "Minnesota Value of Solar: Methodology," p. 2.

The Methodology requires that the estimates of these avoided costs:

- accurately account for all value streams (benefits net of costs) from a societal perspective as required by statute by measuring the actual value of solar energy, rather than providing for growth of an industry[10]
- use simple and transparent methodology and input data sets
- provide for the modification and annual updating of data inputs in future years

As shown in the Table above, the calculation of each of the categories of avoided cost begins with a gross value in $/kWh. Where appropriate, a percentage adjustment is made for a load match factor applicable to capacity related values. Next, a distributed loss savings factor is calculated based on annual energy, effective load carrying capability (ELCC) or peak load reduction (PLR). In each category of avoided cost, a discount factor is applied for each year of the VOS contract.[11]

The final step is to apply an inflation adjustment (or "escalation rate") on an annual basis using the then current rate of inflation. Table 18 in the Methodology (p. 44) shows the present value calculation: a hypothetical calculation of a VOS rate beginning in 2014 and ending 25 years later in 2038. Table 18 shows how the discount rate reduces the future value of solar while the inflation adjustment raises it, resulting in a net discounted cost adjusted for inflation in the far right column. When summed over 25 years the total present value of marginal avoided costs is shown at the bottom. Figure 5, on page 43 of the Methodology, shows the same example in levelized and inflation-adjusted terms. A figure based on the previous example (Figure 4, page 43) shows the proportional relationship between the avoided cost categories in the 25 year levelized case. The relative proportions in the example show that the avoided fuel costs category is the largest followed by avoided environmental costs and avoided generation capacity costs.

The utility would then use the first year value as the credit for solar customers, and would adjust the rate for inflation each year using the Consumer Price Index (CPI). For future solar interconnections under the VOS tariff, the utility is required to recalculate the VOS rate annually and file the new rate with the Commission based on current numbers in all categories. Recalculated VOS rates will also be adjusted for inflation annually.

The Department noted certain misunderstandings of the Methodology and in response to parties' initial comments sought to clarify a number of points:

- the statute specifies that the VOS Methodology will account for the value to the utility, its customers, and society for the five required components (energy and its delivery,

[10] This is different from the Community Solar Garden legislation (Minn. Stat. 216B.1641) that requires any plan approved by the Commission "reasonably allow for the creation, financing, and accessibility of community solar gardens."

[11] Different discount rates are applied to various avoided cost categories, including avoided environmental cost and avoided fuel costs.

generation capacity, transmission capacity, transmission and distribution losses, and environmental value); any optional components (other than the five required components) to be included must be based on known and measurable evidence of the cost or benefit of solar operation to the utility

- the VOS Methodology is required to take a broader assessment than current resource planning and thus requires new analytical approaches

- by statute, the VOS is not 'buy-all-sell-all' (the customer is credited through a bill mechanism)
    - a VOS tariff that appropriately applies the methodology established by the Department will not result in any sale of distributed solar energy by the customer. The customer purchases all of the electricity consumed from the utility at their applicable retail rate and is credited for all of the distributed PV energy produced at the VOS tariff rate.

- the statute specifies a two part VOS process: (1) the Methodology, then (2) the tariff
    - the current docket (14-65) addresses the Methodology issues
    - it is anticipated that a future docket will address tariff issues once a utility applies for approval of an alternative tariff that appropriately applies the Methodology

- the VOS Methodology is designed to be simple (where possible and warranted) and transparent in order to facilitate understanding and implementation
    - the VOS methodology develops a single VOS rate that is based on the utility fleet of PV
    - the value of a kWh of distributed solar PV is not dependent on the type of customer that installed the PV

Key aspects of the VOS Methodology include:

- a standard PV rating convention (p. 14)
- methods to create an hourly PV production time-series, representing the aggregate output of all PV systems in the service territory per unit of capacity corresponding to the output of a PV resource on the margin (pp. 14-16)
- requirements for calculating the electricity losses of the transmission (Table 13, p. 32) and distribution systems (pp, 33-36, Tables 14 & 15)
- methods to perform technical calculations for avoided energy (Tables 9 & 10, pp. 26-27), effective generation capacity (Table 11, p. 29) and effective distribution capacity (pp, 33-36, Tables 14 & 15)
- economic methods for calculating each cost component e.g., avoided fuel cost, capacity cost, avoided environmental cost, etc. (pp. 21-44)
- requirements for summarizing input data and final calculations in order to facilitate review and understanding

Parties disputed the calculation method for a number of the avoided cost value components and the contract term. These are discussed below in the following order:

- avoided fuel cost (fuel cost escalation factor and guaranteed fuel price)
- avoided generation capacity costs
- avoided transmission capacity costs
- avoided reserve capacity costs
- avoided distribution capacity costs
- avoided environmental costs (social cost of carbon and non-CO2 pollutant values)
- avoided SES compliance costs (solar renewable energy credits)
- contract term

Avoided fuel cost calculation

Comments on the Methodology's avoided fuel cost calculation focused on two main issues: the fuel cost escalation factor and the guaranteed fuel price. The DOC maintained that avoided fuel costs are based on long-term, risk-free fuel supply contracts. This value 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 customer through fuel price adjustments.[12] MREA recommended an alternative avoided fuel cost calculation methodology. Staff addresses each of these three issues individually.

Fuel cost escalation factor

Several parties, including Minnesota Power, MREA, OTP, and Xcel, take issue with the Methodology's calculation of avoided fuel costs. MREA and Xcel note that the 4.77 percent escalation factor was calculated using a single quote from September 23, 2013, while the price of natural gas has fallen precipitously since then. When Xcel replicated the Department's calculation using NYMEX data from February 12, 2014, it produced a dramatically different escalation factor of - 0.26%.[13] Furthermore, Xcel argued that if gas prices were to rise at such a high rate for such a long time, "basic supply and demand principles suggest users will find alternative sources of energy that are less costly, while suppliers will bring more natural gas to market to increase their profits. Both of these actions would serve to reduce the long-term price of natural gas."[14]

In its reply comments, the Department agreed that the proposed methodology's escalation factor calculation can be improved. In order to smooth out short term price fluctuations, the Department recommended a revised escalation factor calculation: "30-day averages are used for

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[12] See pp. 22-24, DOC's "Minnesota Value of Solar: Methodology."

[13] Ibid at p. 14.

[14] Ibid at p. 15.

the NYMEX Natural Gas Futures contract prices for years 1 through 12; for years beyond year 12, the general escalation rate is used as the guaranteed fuel price escalation."[15]

Guaranteed fuel price adder

Some parties, such as MP and Xcel, questioned whether a long-term price guarantee adder should be included at all. MP argued that the guarantee goes beyond the statutory requirement and is inconsistent with industry practice. OTP concurred, arguing that 25-year natural gas contracts are "virtually unheard of in today's market."[16] Xcel noted that, for a variety of reasons, it has decided against financial fuel hedging in Minnesota; accordingly, Xcel argued that it has no hedge value for solar to offset. Thus, Xcel believes that the long-term guarantee should be an optional component for the VOS, and should be separated from the avoided energy cost calculation.

In reply comments, the Department and the Environmental Organizations[17] disputed this point. As the Department noted, "[l]ong term fuel price risk is a cost that is incurred by the utility and passed on to its customers through rate changes in the fuel adjustment clause and elsewhere."[18] Specifically, EO pointed out that Xcel adjusts for fuel price volatility through its Fuel Cost Adjustment (FCA) Rider; therefore, Xcel's customers currently bear the risk of fuel price volatility, so the stability of solar fuel costs does constitute an avoided cost.

Alternative Avoided Fuel Cost Calculation

MREA recommends an alternative methodology for calculating the avoided fuel cost: a locational marginal price (LMP) of fuel for each utility. LMPs, which would be calculated using the MISO wholesale energy market, could be updated yearly to track market conditions.

Avoided Generation Capacity Costs

The DOC's Methodology for determining the avoided generation capacity cost is based on a weighting of the capital cost of combustion turbines (CTs) and combined cycle gas turbines (CCGTs) according to the marginal solar heat rate, which is multiplied by (i.e. reduced by) the Load Match Factor (ELCC) in recognition that capacity related benefits are time-dependent.

MP, MREA, and Xcel disagreed with aspects of the Methodology's calculation of avoided generation capacity costs. MP and Xcel contend that the inclusion of CCGTs will overestimate

[15] Department reply comments, February 20, 2014, p. 13.

[16] OTP initial comments, February 13, 2014, p. 13.

[17] "Environmental Organizations" (EO) represent joint comments filed on behalf of: the Environmental Law and Policy Center, Fresh Energy, Interstate Renewable Energy Council, Institute for Local Self-Reliance, Izaak Walton League of America, SunEdison, and the Vote Solar Initiative.

[18] Department reply comments, February 20, 2014, p. 13.

the avoided generation capacity, as their current investment plans call for less expensive generation capacity additions. They recommended that the calculation be based solely on CTs.

In addition, MREA and Xcel noted that the Methodology does not allow for delaying avoided generation capacity costs for utilities that do not currently need additional generation capacity. Xcel argued that, since its resource plans do not anticipate additional generation capacity needs until 2017 (or even beyond), the avoided generation capacity costs should not be calculated until there is an identified capacity need.

In reply comments, EO took issue with Xcel's characterization of its avoided generation capacity costs. As they put it, "While the next marginal unit for Xcel's capacity construction might not occur until closer towards 2017, it is important to note that utilities frequently are going to the market for spot-purchases and short-term capacity contracts to cover any imbalances."[19] Thus, the Environmental Organizations contend that there will be some avoided generation capacity costs for Xcel before 2017.

In replies, the DOC indicated that the goal of the method is to represent the avoided cost of capacity over the full 25 year life of the PV resource, not only the near term avoided capital costs as proposed by Xcel. In the long term, both CCGT and CT capacity will be needed; both are needed to meet demand. The weighting method simply apportions CCGT and CT costs according to what resources will actually be offset. Moreover, if only CTs are assumed, avoided fuel costs would be much higher due to the higher CT heat rates.

The DOC agreed that current prices for installed capacity should be used and that the Methodology allows the utility to enter current market prices for CTs and CCGTs in the VOS Data Table, to use in the calculation of the VOS rate.

Finally, the DOC explained that the contribution of distributed solar PV to deferral of new generation capacity must be considered when evaluating the timing of future generation. By statute, the VOS credit "shall represent the present value of the future revenue streams of the value components." Distributed solar PV is a modular resource that is developed and installed in smaller increments than larger additions of typical utility-sized generation, which is more typical of the way actual "demand" on the system develops. This feature of distributed solar PV contrasts with conventional generation resources such as gas peaking units which are added in block increments of several hundred MW each.

Avoided reserve capacity costs

The Department's Methodology derives the avoided reserve capacity cost by multiplying the avoided generation capacity cost by the assumed reserve capacity margin percent.

[19] EO reply comments, February 20, 2014, p. 6.

Xcel argued that avoided reserve capacity cost should be excluded or calculated as zero because distributed solar resources do not lower reserve margin requirements and to account for them would contradict findings by FERC.[20] Moreover, reserve margin is based on total load not generation. Since solar generation cannot be counted as an offset to load, loads are not reduced, and reserve capacity margins under MISO tariff and business practices are not reduced.

In reply, the Department explained that FERC's finding is not applicable because it addresses only behind-the-meter generation. Under the VOS statute, the alternative tariff "charges the customer for all energy consumed by the customer." Consequently, none of the energy provided by the solar generation may be used to reduce the load behind the meter; therefore these distributed solar resources cannot be considered behind-the-meter resources.

The DOC noted that the solar generation does, however, represent a distributed resource that provides corresponding distributed benefits. Therefore, reserve margin should be based on total load. Since the utility measures coincident load at the substation (e.g., at the transmission level), then all VOS resources participate in reducing total load. This aggregation provides an extremely high level of redundancy not observed with centralized generation (whether fossil or renewable).

For example, if combined VOS resources are providing 100 MW in a given hour, and if the average VOS system is rated at 50 kW, then a forced outage of a single unit would still allow the aggregate resource to deliver 99.950 MW (99.95 percent retention). Conversely, the loss of a 100 MW gas turbine would result in the loss of the full 100 MW (0 percent retention). In addition, the Methodology already accounts for weather-related outages through the use of the ELCC metric.

Avoided transmission capacity costs

The DOC's Methodology for calculating the avoided transmission capacity cost is based on the utility's 5-year average MISO OATT Schedule 9, which is multiplied by (i.e. reduced by) the Load Match Factor (ELCC) in recognition that capacity related benefits are time-dependent.

In its reply comments, the DOC noted that, in addition to functioning as a generation resource, distributed solar PV is expected to reduce the need for future capacity investments in transmission by serving load locally. Since transmission tends to be added in rather large increments, the benefits are expected to accrue over time, but are important to recognize in the rates paid for solar energy. Thus, the incremental effect of distributed generation to push future transmission capacity requirements farther into the future are correctly recognized for by accounting for transmission capacity benefits over the analysis period.

[20] Xcel cited FERC Docket Nos. ER08-394-004 and ER08-394-005, in which FERC determined that resources such as distributed solar should not be netted from load and would, therefore, not create a reserve capacity benefit. See Xcel's initial comments, p. 19.

In addition to deferring future transmission investments, the EO argued that DSG frees up capacity on existing transmission systems. Even systems facing zero-load growth will see reduced costs: utilities that do not own transmission will have to purchase less transmission service and utilities that own their transmission system will see reduced capacity, giving them the option to "rent" transmission capacity to other load-serving entities.

The Department asserted that solar PV reduces peak demand and the Planning Margin Reserve Requirement (PMRR). The PMRR and transmission loading during peak demands are tied to Xcel's projection of its forecasted peak at the time of the MISO annual peak as well as Xcel's stand-alone peak. During the past 10 years or so, the peak for both native load purposes and the peak for PMRR has always occurred during afternoon daylight hours in July or August, when solar is expected to produce power; further, a key variable in the Xcel forecast is solar irradiance. Solar PV therefore reduces peak demand which reduces peak demand transmission loading.

The Department argued that MISO's Network Integration Transmission Service (NITS) is a proper proxy for avoided transmission costs, noting that Xcel has confirmed use of this approach in other dockets. And, because of the MISO revenue crediting mechanism under Schedule 26A, the DOC believes the NITS charge is not unduly impacted by multi-value projects or wind transmission projects.

MP and Xcel, on the other hand, raised several objections to the avoided transmission capacity calculation in the proposed Methodology. MP noted that it is not clear which five-year MISO average the Methodology refers to: the five-year historical average, the five-year forward-looking average, or some other period. Moreover, MP argued that historical averages "clearly do not represent transmission costs that can be avoided," and forward-looking averages primarily reflect sunk costs of existing transmission systems. In addition, Xcel argued that the proposed MISO rate does not represent any savings because, under MISO's transmission service charge rules, Xcel's transmission payments would be unaffected.

Accordingly, MP and Xcel recommended an alternative avoided transmission cost calculation: the cost of future transmission investments that could truly be avoided as a result of DSG additions. As Xcel put it, DSG "will not materially change network flows, but could eventually, if at a large-enough scale, avoid a network resource." Xcel noted that some transmission capacity, such as the transportation of RPS-mandated wind power, will be unaffected by DSG. The replaced resource would most likely be a deferred or avoided natural gas investment. Thus, Xcel recommended that the avoided transmission cost be calculated by the avoided transmission upgrade costs due to the interconnection of planned natural gas units.

In response, the Union of Concerned Scientists (UCS) contends that Xcel's definition of avoided transmission capacity is too narrow. The UCS argued that Xcel takes too narrow of a view of avoided transmission costs when it assumes that only future upgrades should be considered because "there are costs to ratepayers and wholesale customers based on the incremental demand for transmission service, and that the price signal or value that reflects the incremental change to demand is reasonable and appropriate." Moreover, the UCS asserted that even if Xcel's definition is accepted, not all new power plants will be able to be built on existing sites, so, even by its own definition, Xcel is understating the avoided transmission costs.

Avoided Distribution Capacity Costs

The Department included avoided distribution capacity costs in the calculation of the VOS rate. The DOC proposed the costs may be calculated in either of two ways: (1) through system-wide avoided costs (using capacity investments through FERC accounts and peak demand growth rates over the past 10 years), or (2) through location-specific avoided costs (planned capital investments in a given planning area). The location-specific method would allow for a higher-value rate in areas where capacity is most needed. On pages 33-35 of the Department's VOS Methodology, there is a list of the FERC accounts that would be included, adjusted for only capacity-related amounts; an example; and additional clarifications.

Xcel raised concerns about the DOC's Methodology. Under the system-wide approach (Xcel's preferred approach at this time), the assumption is that calculating cost per unit is a reflection of growth. However, capacity investments can be driven by reliability issues rather than growth, or could be driven by past periods of strong load growth.[21]

Xcel also pointed out that the FERC accounts identified by the Department contain costs due to other drivers, such as equipment replacement and new extensions. Xcel recommended that the calculation be adjusted to consider costs related only to capacity additions. The Company also stated that their initial evaluation suggests there are very few feeders where DSG has the potential to avoid or defer distribution investment. This is partly due to the peak demand of residential customers occurring later in the evening after solar resources have stopped producing energy and the intermittent nature of solar. As recognized by the integration cost placeholder, the addition of distributed solar to the grid will result in increased capital expenditures, as well as operating costs, over the long term.

MP opposed the Department's proposed methodology, as follows:

> Within the Department's Report, there is an assertion that the rate derived from the VOS calculation will have no negative impact on Minnesota Power ratepayers. If the VOS methodology is used to develop rates applicable to solar energy purchases, and the costs of those purchases are then paid for by ratepayers, that statement is not accurate. In general, the distribution inputs/benefits are overstated and the costs of implementation are not considered. This is primarily due to the fact that, as the PLR will indicate, there is very little overlap between peak solar production and peak system usage on a site-by-site basis.
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> - Unless cost effective methods of storing and dispatching the energy are introduced, savings from Avoided Distribution Capacity Cost and Avoided Distribution Line Losses will not materialize. In fact, they may very well turn out

[21] Xcel initial comments, p. 17.

to be increases rather than reductions. This is primarily due to the fact that sizing the solar generation to the on-site load based on total monthly energy rather than capacity will likely result in peak generation capacity at each site that is two to three times the peak usage. That excess energy needs to be distributed throughout the system the same as energy from conventional generation (distribution substations from a distribution perspective). The line losses will remain as will the very real potential for system capacity increases, rather than decreases, on a site specific basis.

- General administrative and engineering expenses associated with creating and maintaining the studies and databases related to PLR, Fleet Shape, mapping and tracking within the GIS, and either the System-wide or Location-specific Avoided Distribution Capacity Cost studies, although currently unidentified, will likely be substantial and the costs will be spread over all other ratepayers.

- The proliferation of "foreign feeds" on a utility's distribution system has the potential of negative impacts in the areas of:
    - Increased SAIDI (outage duration) associated with switching, and
    - Increased safety concerns for line personnel associated with potential back feed onto the system.[22]

OTP raised concerns similar to MP, stating generally that due to its variability, PV imposes more costs to the system, not less.[23]

The Environmental Organizations supported the Department's proposed methodology and in particular the quantification of the location-specific avoided costs distributed solar can provide, noting that the statute specifically references the development of a credit for "systems installed at high value locations" as an option.[24] The benefits can be quite substantial, such as the deferment of $84 Million in transmission upgrades for the Long Island Power Authority.

In replies, the Department proposed an improvement to its Methodology, to set the distribution peak load growth rate based on the utility's estimated future growth over the next 15 years. The utility would estimate distribution peak load growth rate over the next 15 years and show the method for estimating it. If the result is zero or negative (before adding solar PV), the avoided distribution capacity cost would be set to zero.

[22] MP initial comments, February 13, 2014, pp. 6-7.

[23] OTP initial comments, February 13, 2014, p. 4.

[24] EO initial comments, February 13, 2014, p. 7.

Avoided Environmental Costs

Several parties, including MP, MREA, OTP, and Xcel, disagreed with the proposed Methodology's calculation of avoided environmental costs, while others, such as the Environmental Organizations, endorsed it. There are two primary contested issues: the use of the EPA's Social Cost of Carbon (SCC) and the inclusion of pollutants other than CO_2. The DOC noted that avoided environmental costs are to be determined based on the value to the utility, its customers, and society.

Social Cost of Carbon (CO_2)

In its Methodology, the Department opted to use the social cost of carbon (SCC) value rather than the Commission-established externality value for CO_2. In its reply comments, the Department elaborated on the rationale behind this decision:

> [T]he social cost of carbon is used to estimate the value to society of marginal reductions in carbon emissions. Since the VOS methodology is an analysis of the value of solar energy compared to the resources it is displacing on the margin, the use of a marginal carbon damage factor best matches the methodology's framework.[25]

The Environmental Organizations also endorsed this decision, arguing that, if anything, the SCC is a *conservative* estimate of the impact of CO2 on human health and the economy. Specifically, the groups' reply comments note that the SCC calculation does not include the economic impact of drought, power outages, and forest fires, and does not include the human health benefits associated with decreased smog.

In addition, the EOs cited the support of the Minnesota Pollution Control Agency (PCA) and a recent University of Minnesota pollution cost study. The Environmental Organizations refer to a report by economists at the University of Minnesota that estimated economic costs for several air pollutants, which recommends use of the SCC approach.[26] In addition, the groups point out that the PCA believes the SCC represents "the best available estimate of the environmental and other nonmarket costs of GHG emissions," noting that the PCA suggested that the Commission consider using the SCC in future proceedings.[27] As another reason to support the use of the EPA SCC, the Environmental Organizations pointed to the State's GHG goals.

MP, MREA, and Xcel, on the other hand, noted that the SCC is unresolved and under review and contend that the range of costs it considers is too broad. MP asserted that the SCC is "far from being an established authoritative standard,"[28] and MREA noted that the federal government has

[25] Department reply comments, February 20, 2014, p. 22.

[26] "Health and Environmental Costs of Electricity in Minnesota," Andrew Goodkind and Stephen Polasky, University of Minnesota, September 26, 2013.

[27] EO initial comments, February 13, 2014, p. 12.

[28] MP initial comments, February 13, 2014, p. 5.

recently opened the SCC process and results to review. In addition, Xcel pointed out that the SCC includes a broad range of factors, including changes in agricultural productivity and increased flood risk. As Xcel put it, the SCC's purpose is to "estimate the climate benefits associated with federal rulemakings on a provisional basis, not to be a precise value in resource planning or ratemaking."[29] Thus, the SCC goes beyond the costs that the utilities would avoid.

A preferable solution, these parties maintain, would be to calculate the avoided environmental cost of CO_2 using the Commission's existing externality value. This value was established by the Commission in a transparent process with extensive stakeholder involvement. Moreover, Xcel asserted that this value is "an approximation of the potential real costs the Company and our customers might expect to pay under a future carbon regulation framework," making it a more accurate measure of avoided environmental costs than the SCC.[30]

Non-CO_2 pollutant values

Xcel and OTP also objected to the Methodology's inclusion of non-CO_2 pollutants in the avoided environmental cost.[31] These values represent the effect of pollutants on society, not on a specific company or industry. As Xcel put it: "Externalities should not be included in the VOS rate because they are not costs that are incurred by the utility system and passed along to customers, and cannot be avoided by the installation of distributed solar on the system."[32] In addition, MP asserted that the avoided costs of these pollutants are not known and measurable, and, thus, the Methodology goes beyond what is required in the statute.

The Department and the Environmental Organizations, however, argued that the inclusion of these values is consistent with the VOS legislation. In the EO's words:

> The fact that many of the avoided environmental costs accrue to society, rather than the utility, is explicitly recognized and embraced by the statute, which specifies that the VOST "compensates customers […] for the value to the utility, its customers, and society for operating distributed solar photovoltaic resources interconnected to the utility system."[33] [34]

Further, the Environmental Organizations asserted that the pollutant costs are both known and measurable, citing a September 2013 study by economists at the University of Minnesota that

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[29] Xcel initial comments, February 13, 2014, p. 11.

[30] Ibid, p. 10.

[31] OTP opposed inclusion of any avoided environmental costs.

[32] Xcel initial comments, February 13, 2014, p. 12.

[33] EO initial comments, February 13, 2014, p. 11.

[34] Minn. Stat. §216B.164, subd. 10(a).

developed costs for various air pollutants based on their effects on environmental and human health.[35]

Geographic focus of externality values

The DOC Methodology uses the midpoint of the low and high urban range of the Commission's 1997 externality values (inflated into 2012 dollars) for carbon monoxide (CO), particular matter (PM10), sulfur dioxide (SO2), and lead (Pb). In its comments, the Minnesota Rural Electric Association (MREA) questioned why the urban values were chosen, when the Metropolitan Fringe or Rural values may be more appropriate for utilities with service territories in greater Minnesota.

MREA took issue with the geographic focus of the Commission-approved externality values used in the Methodology. The proposed Methodology calculates the cost of the non-CO2 pollutants using the midpoint of externality costs of the Commission's Urban scenario. MREA noted that the externality costs for the Metro Fringe and Rural values are lower than their urban counterpart. Therefore, MREA argued the VOS rate will overstate the avoided environmental costs for rural ratepayers.

In reply, the Department explained that the urban values were used to simplify data collection, one of the objectives of the Methodology. However, the Department agreed with MREA's proposal to allow utilities to select the non-CO2 externality values that are most applicable to their service territory. The DOC added this option as a revision to the Methodology.

Avoided Solar Energy Standard (SES) compliance costs (Solar Renewable Energy Credits)

Many parties, including CEO, CRS, MnSEIA, MRES, and several homeowners with solar installations, took issue with the fact that the methodology does not explicitly include compensation for the value of the solar renewable energy credits (SRECs), even though the VOS statute grants them to the purchasing utility.[36]

As the Environmental Organizations argued, SRECs are measurements of not only environmental attributes, but also compliance attributes. The Methodology accounts for the environmental attributes through the avoided environmental costs component, but these benefits would exist even without a solar compliance requirement. The SES imposes a compliance cost, or as EO referred to it, a "cost of adoption." Thus, these additional avoided compliance costs are a distinct value component, benefiting utilities and ratepayers over and above the environmental benefits to society, and they should be accounted for in the Methodology.

[35] "Health and Environmental Costs of Electricity in Minnesota," Andrew Goodkind and Stephen Polasky, University of Minnesota, September 26, 2013.

[36] Minn. Stat. §216B.164, subd. 10(i).

As the Environmental Organizations argued, while the statute does not specifically mention avoided compliance costs, the Legislature allowed for the inclusion of additional value components.[37] Including avoided compliance costs is consistent with Legislative intent, as the section that includes the new VOS statute is to "at all times be construed in accordance with its intent to give maximum possible encouragement to cogeneration and small power production consistent with protection of the ratepayers and the public."[38]

As a remedy, several homeowners with solar installations suggested the Methodology include a placeholder for the value of SRECs, so that, once a price for SRECs in Minnesota has been established, it could be included in the calculation. MnSEIA goes further, recommending a compensatory value of $0.06 /kWh.[39] In addition, the Minnesota Renewable Energy Society (MRES) recommended that DSG owners be given the right to buy-back any SRECs associated with their generation.

Xcel and the Department disagreed that additional compensation is necessary. In reply comments, Xcel argued that there is no separate compliance value associated with an SREC, as RECs represent the distinguishing characteristics of renewable energy; as the Company put it, RECs represent the "renewableness" of the energy, and "without these attributes the energy would not be considered renewable and would not be eligible for compliance."[40] Thus, the compliance and environmental attributes are one in the same.

In its reply comments, the Department asserted that compensation for SRECs is included in the Methodology. The Department noted that, while externalities have been considered in utilities' resource planning, the inclusion of externalities in rates is unique to the VOS. Thus, the SRECs are not being transferred to the utility for "free," and additional compensation for the avoided SES compliance costs are not necessary. Also, the DOC noted that estimating the supply and demand of SRECs as far out as would be required, is not "known and measureable" at this time.

In reply comments, the Environmental Organizations suggested that:

> "[I]n order to avoid potential double-compensation for avoided environmental costs, it may be necessary to subtract that value component from standard SREC prices and/or market proxy prices in order to arrive at a reasonable dollar-per-kilowatt-hour estimate of the compliance-value component SRECs transferred under VOST."[41]

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[37] Minn. Stat. §216B.164, subd. 10(f).

[38] Minn. Stat. §216B.164, subd. 1.

[39] MnSEIA initial comments, February 13, 2014, p. 3.

[40] Xcel reply comments, February 20, 2014, p. 3.

[41] EO reply comments, February 20, 2014, p. 10.

Contract term

The Department, in its proposal, recommended a 25 year contract. Three (3) commenters opposed this aspect of the Department's proposal (MP, MREA, and OTP); three commenters supported or did not oppose it (Xcel, EO, and MnSEIA).

MREA suggests a 20 year term because they believe it reduces uncertainties inherent in the cost and benefit assumptions made for PV resources in years 21-25; MP, likewise, believes that since the methodology is new and fraught with uncertainty in the inputs, calculations, and impacts, the shortest term contract possible (20 years) should be used.

In reply comments, MRES suggests that 25 years should be the minimum acceptable term of years, and points to the Department of Energy's determination that the average useful life of a PV unit as 30 years.[42] The Department replied that it chose 25 years based upon the numerous industry and research sources that identify 25 years as the average lifespan of a PV panel.

In addition, the DOC noted that a 20-year contract term would leave PV contractors uncovered for the last 5 years of the useful life of a project, and it is unclear if a new contract would be offered for the remaining time period.

Parties' proposals for additional value components

The DOC's Methodology includes eight avoided cost components and two placeholders.[43] Many of the parties supported the DOC's selection of specific cost components, including the two placeholders. However, some parties recommended that additional value components be incorporated, as discussed below.

Economic Development Benefit Adder

The Department's proposed Methodology does not include a value component for an economic development benefits. MnSEIA believes these benefits are "known and measurable" and do result in building load for the utility. MREA noted that the specific mention of this value component in the VOS statute was intended to invite robust debate on the issue. The EO found the arguments of MnSEIA persuasive and in replies recommended inclusion of an economic development value component.[44]

MnSEIA suggested that because of the increased tax revenues, reduced unemployment, and other benefits, an economic adder should be included. Citing to Xcel's 2012 rate case, MnSEIA noted that the Commission has already approved incentive programs to retain or expand businesses that are beneficial to all ratepayers. MnSEIA suggested a number of ways to set this adder: CPR has

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[42] MRES reply comments, February 20, 2014, p. 6; EO reply comments, pp. 11-12.

[43] The placeholder for Solar Integration Costs would not be an avoided cost/benefit but would a cost.

[44] EO reply comments, February 20, 2014, pp. 11-12.

set out an equation to develop an economic development value based on tax revenue benefits, Xcel may be able to provide data directly, or through the NREL Economic Development Impact modeling program. MnSEIA estimated the per kWh benefit to be about $0.06/kWh.[45]

In reply comments, MRES and the Environmental Organizations supported MnSEIA's recommendation.[46] However, Xcel pointed out in reply that the citation to Xcel's rate case can be differentiated from the VOS docket, because those economic development incentives refer to adding and retaining load, which allows fixed costs to be spread over a larger sales base. Distributed solar does not increase consumption and therefore does not create the same direct benefit.[47] OTP, likewise, responded to MnSEIA that the statute requires "known and measurable" evidence of a cost or benefit, and the calculation of these benefits would be theoretical. In addition, OTP argued, all generation, transmission, and distribution projects confer some economic development benefits; the VOS methodology should only credit values to attributes that are unique to this resource.[48]

Important to understanding MnSEIA's positions are the comments filed by the Association as part of the DOC stakeholder process.[49]

Market Price Reduction Adder

The Environmental Organizations suggested a "Market Price Reduction" placeholder, relating to a possible decrease in wholesale electricity prices stemming from a reduction in demand due to solar.[50]

Xcel replied that the premise is flawed and should not be assigned a placeholder, because this is another area where distributed solar would not create a benefit that is different from other resource options.[51] The value of energy produced by solar installations is already captured in the avoided capacity, fuel cost, and O&M components of the VOS Methodology. Additionally, Xcel plans its system to have sufficient generation to meet its customers' load.

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[45] KWh number derived from a 1 MW solar array producing 29,444,000 over 25 years and benefits the state $2.4M.

[46] MRES reply comments, February 20, 2014, pp. 3-4.

[47] Xcel February 20, 2014 replies at pp.5-6. Further, Xcel notes that utility-scale solar, which is allowed for compliance with the Solar Energy Standard, also creates jobs and supports economic development at a lower cost.

[48] OTP reply comments, February 20, 2014, p. 1.

[49] See MnSEIA comments at: http://mn.gov/commerce/energy/images/Minnesota-Solar-Energy-Industries-Association_VOS%20Comments.pdf

[50] EO initial comments, February 13, 2014, p. 17.

[51] Xcel reply comments, February 20, 2014, p. 5.

Capacity Enhancement Adder for the use of PV tracking systems or non-standard orientations

In their initial comments, EO advocated for the inclusion of a "capacity adder" to compensate DSG installations that use tracking systems or non-standard orientations to enhance capacity benefits. The Environmental Organizations asserted that systems using non-standard orientations, such as west facing, to enhance capacity benefits are at a disadvantage under the current methodology, which solely rewards production. Similarly, the Environmental Organizations argued that "a tracking system can contribute greater capacity value by nature of optimizing maximum output (kW), not production (kWh). Such a system will generally produce less energy because it is optimized to maximize capacity and produce most during system peak."[52] Although this marginal capacity maximization benefits both utilities and ratepayers, the producers may receive *less* compensation than similar arrays that do not optimize capacity.

Accordingly, the Environmental Organizations recommended that systems with these additional attributes be compensated for capacity maximization through the inclusion of a capacity adder. Specifically, the groups suggested the use of the National Renewable Energy Laboratory's (NREL's) PVWatts model to calculate this benefit.

The Department responded that its Methodology does, in fact, account for the added capacity value of these systems. In the Department's words, "the MISO BPM approach accounts for the added value of those PV plants in the utility PV fleet that have panel orientations (e.g. west facing) and technologies (e.g. tracking) that can increase the capacity value."[53] Additionally, in its reply comments, Xcel argued that EO's proposal would increase the complexity of the Methodology, and that the Methodology's current fleet approach appropriately balances accuracy and simplicity.

Avoided costs of water consumption and land use ecosystem impacts

The Environmental Organizations indicated that distributed solar generation avoids costs associated with water consumption, the use of fossil fuels and thermal generation, and impacts on land and ecosystems. Although these environmental sub-components were not included in the DOC Methodology, the EOs suggested a placeholder so that in the future these avoided costs could be incorporated.[54]

Issues outside the scope of the Notice seeking comments in this docket

Transparency of VOS rate calculation

In initial comments, the Environmental Organizations expressed concern over the transparency of the calculations to be used in the Methodology and encouraged the Commission to provide

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[52] EO initial comments, February 13, 2014, p. 16.

[53] DOC reply comments, February 20, 2014, p. 8.

[54] EO initial comments, February 13, 2014, p. 13.

greater access to utilities' confidential information and system modeling software. The EOs argued that "ELCC studies are frequently opaque to non-utility stakeholders and have run into situations in other states where the 'fleet shape' was based on too few actual projects."[55] This is particularly important early in the value of solar rate development process. The groups recommended that the Commission pay careful attention to these calculations.

In reply comments, OTP raised concerns about EO's comments. While the Company understands the importance of transparency, it notes that the data that are labeled "confidential" are often contractually required to be so. Similarly, the modeling software used in these calculations is also often proprietary. Accordingly, the Company "recommends that the Commission act cautiously with respect to requiring a utility to disclose proprietary business information."[56]

PURPA compliance and effect on net metering options

One set of public comments (Bill and Nancy Bauer) expressed concern that net metering could potentially be lost if a VOS tariff was adopted and urged the Commission to retain net metering.

The Alliance for Solar Choice (TASC) shared the concerns expressed by the Bauers and asked to Commission to provide guidance on the issue. TASC stated that the DOC Methodology and interpretation of its application would conflict with the Public Utility Regulatory Policies Act of 1978 (PURPA), which provides customers with a right to serve onsite load with a QF. The VOS provisions exist within the statutory section that implements PURPA, and in TASC's view any interpretation that does away with a customer-generator's right to serve onsite load under subsections 3 and 3a would not be compliant with PURPA. TASC also expressed additional concerns that some interpretations could constitute a regulatory taking.[57]

TASC further requested that the Commission require the following revisions to the Department's Methodology (TASC's added language is underlined):

- "[I]f a VOS tariff is approved, solar customers <u>that opt, at their election, to sell under a full buy/sell arrangement</u> will be billed for all usage under the existing applicable tariff, and will receive a VOS credit for their gross solar energy production."

- "Energy derived from the PV systems <u>in which the owner has opted, at its election, to sell under a full buy/sell arrangement</u> will not be used to offset ('net') usage prior to calculating charges."

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[55] EO initial comments, February 13, 2014, p. 6.

[56] OTP reply comments, February 20, 2014 February 20, 2014, p. 2.

[57] TASC initial comments, February 13, 2014; TASC reply comments, February 20, 2014.

In reply comments, Xcel stated that statute and legislative intent support the VOS tariff as a replacement for net metering for new solar installations and explains why they believe TASC's interpretation of "rate" is misguided. The term "rate" is defined in state statute to include all tariffs, rules, practices, and contracts affecting the rate charged.[58]

The Department also replied generally, noting that by statute, the VOS is not "buy-all-sell-all," that this phase of the process was methodology only, and a future docket would address tariff issues when a utility applies for approval of an alternative tariff that appropriately applies the Methodology.[59]

Staff comment

Minn. Stat. 216B.164, subd. 10 (b) states:

> If approved, the alternative tariff shall apply to customers' interconnections occurring after the date of approval. The alternative tariff is in lieu of the applicable rate under subdivisions 3 and 3a.

Subdivision 3 referenced in subdivision 10 above sets out requirements for utility purchases from small facilities, defined as under 40 kW for cooperatives and municipal utilities and under 1,000 kW for public utilities. Subdivision 3a sets out requirements related to utility purchases from net metered facilities of more than 40 and less than 1,000 kW connected to a public utility. This latter subdivision states explicitly that it does not apply to customers receiving a value of solar rate under subdivision 10:

> Subd. 3a.**Net metered facility.**
> (a) **Except for customers receiving a value of solar rate under subdivision 10**, a customer with a net metered facility having a capacity of 40 kilowatts or greater but less than 1,000 kilowatts that is interconnected to a public utility may elect to be compensated for the customer's net input into the utility system in the form of a kilowatt-hour credit on the customer's energy bill carried forward and applied to subsequent energy bills. Any net input supplied by the customer into the utility system that exceeds energy supplied to the customer by the utility during a calendar year must be compensated at the applicable rate.
> . . . .
> [Emphasis added]

The statute seems clear that for new solar PV facilities interconnected after approval of a VOS tariff, net metering is no longer an option. TACS's attempt to make a distinction between the tariff and the rate is not convincing, especially given that the statute states that the alternative **tariff** is in lieu of the applicable **rate**.

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[58] Xcel reply comments, February 20, 2014, p. 6; MP reply comments, February 20, 2014, pp. 2-3.

[59] Department reply comments, February 20, 2014, p. 5.

TASC also seems to imply in its comments that elimination of the net metering option for solar PV generators would somehow violate PURPA. If that is what TASC is contending, then staff disagrees. There is no federal right to net metering, and the term "net-metering" is not used anywhere in PURPA (16 U.S.C. §824a-3), nor in the related FERC rules implementing PURPA (C.F.R. Title 18, Part 292). PURPA establishes the right of small generators who are Qualifying Facilities (QFs) to generate electricity and the requirement that utilities purchase all the energy produced if relevant conditions are met.

Minnesota was the first state to establish net metering in statute; currently approximately 42 states, and other jurisdictions, allow some form of net-metering. Utilities in Minnesota must offer net-metering to qualified generators, but also must offer other options.

Under Minn. Stat. §216B.164, subd. 3 and 3a QFs may choose net metering.[60] However, the QF may instead elect to be governed by the provisions of subdivision 4, which allows the QF to sell the energy it makes available at avoided cost set by the Commission or at a negotiated rate. For smaller facilities, Minn. Rules, Chapter 7835[61], the Commission's rules implementing Minn. Stat. §216B.164, allow QFs under 40 kW to choose net metering, but also allow the QF to choose a time of day rate or simultaneous purchase and sale rate.

Staff notes that net metering would still be an option for all new QFs under 40 kW connected to cooperative or municipal utilities, and for new QFs connected to a public utility who generate with wind or any other qualified non-solar PV generation.

Minn. Stat. §216B.164, subd. 10 specifically states that the VOS tariff applies to solar PV interconnections occurring after the date of tariff approval. The statute is silent on whether existing net-metered solar PV customers can choose to switch to a utility's VOS tariff once it is offered. This appears to be a policy call for the Commission.

Effect on and consistency with other Commission proceedings

In general, some parties noted that the values or analyses proposed by the Department were not consistent with that of other dockets. Parties noted that the federally-proposed Social Cost of Carbon (SCC) is a different value than the Commission's approved carbon value that is used in resource planning proceedings. Xcel also noted that some of the Methodology differs from the precedent in its resource planning process.

The Environmental Organizations observed that the VOS tariff is a combination of both ratemaking and resource planning and it is up to the Commission to determine whether the Department struck the right balance between ratemaking and resource planning perspectives. In

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[60] Except for customers receiving a value of solar rate.

[61] The Commission's rules are in the process of being updated to reflect the 2013 statutory changes. See Docket E-999/R-13-729.

addition, the EOs state they do not read the proposed Methodology as requiring changes to the resource planning process and suggest Xcel's concerns be addressed in other relevant dockets.[62]

Staff notes that the Commission's environmental externalities docket has recently been reopened and while no decisions have been made, some parties in that docket have recommended the SCC be adopted. If the Commission prefers, it could clarify in its Order that its adoption of the Department's Methodology and the values contained in it in the current docket is a determination based upon the circumstances unique to this docket and should not be interpreted as prejudging a decision in any pending or future Commission proceeding. Staff has included this as a decision option.

Clarity and disclosure on utility ownership of RECs

The Center for Resource Solutions (CRS), which administers Green-e Energy, the certification and verification consumer protection program for renewable energy sold in the voluntary market, filed comments. CPR pointed out that while the statute is clear about REC transfer, a generator could easily not understand that RECs are owned by the utility. Through billing or other disclosures, generators and other parties should also be annually (or more frequently) notified of the exact amount of RECs being transferred to the utility.

Staff agrees that it should be made clear to the generator that under a VOS tariff, RECs are transferred to the utility pursuant to statute. However, this proceeding is focused on the Department's proposed Methodology, not what conditions should be imposed on a utility if and when it wishes to adopt a VOS tariff. Staff suggests that the Commission make clear that any utility filing a proposed VOS tariff should discuss, in its initial filing, whether and how disclosures on REC ownership should be made to the generator. Staff notes that for Xcel's Solar*Rewards program, Xcel's tariff specifies that Xcel owns the RECs, so this issue is not isolated to VOS.

Additional processes to evaluate VOS effectiveness

In reply comments, Xcel noted the following:

> [W]e note that Department Staff has recommended approval of a Solar*Rewards incentive of $0.08/kWh. The Made in Minnesota program offers incentives ranging from $0.13 - $0.39/ kWh. These incentives are in addition to compensation received through the VOS and can be adjusted based on market response. Should additional compensation be required to achieve the desired level of customer adoption, we are willing to work with parties on incentive options that are separate from the base VOS components.

[62] EO reply comments, February 20, 2014, p. 5.

> Additionally, while we should do our best at the outset to get the methodology as accurate as possible, we recognize that VOS is a new concept for Minnesota and the solar industry is in early stages of growth. We believe there should be opportunities beyond just an annual update of cost inputs to periodically assess the effectiveness of the VOS tariff at achieving its objectives and to evaluate the need for adjustments based on new information, evolving environmental regulations, and other developments affecting VOS. This is similar to the report and evaluation approach taken with CIP performance incentives. The intent would not be to revisit the basic foundation of the methodology, but to determine whether there are additional benefits and costs that should be quantified and refinements that are needed to best reflect the demonstrated value of solar. It could also provide a clearer path for addressing the placeholder values. For example, the evaluation might reveal new information on integration costs and produce a method to quantify those costs for inclusion in the methodology.
>
> We recommend revisiting the methodology once we, as a state, have two years of experience implementing a VOS tariff through one or more utilities. Because statute requires the VOS rate to be at least the retail rate for the first three years, we believe it makes sense to revisit the VOS methodology before that rate floor expires.[63]

Staff agrees that it is consistent with Commission practice and process to actively evaluate the effectiveness of a new rate. A reporting and evaluation requirement is common among new rates and programs: other examples include the reports and evaluation the Commission has required of Minnesota Power for its residential Time of Use (TOU) pilot, the annual reports and evaluations of the Gas Affordability Programs, and Xcel's recently approved Community Solar Garden program.

Staff has included a general decision option based upon Xcel's recommendation; further clarifying language on the specifics of the contents of reports and evaluations may be necessary either at this time or if and when a utility files a VOS tariff.

However, staff is unsure of the mechanics of proposing a new Methodology, if and when it would need to be revised. The statute refers to the Department filing the Methodology with the Commission by January 31st of this year, but is silent on later revisions to the Methodology. The Commission may not need to decide this matter now and can take it up when an evaluation is made.

[63] Xcel reply comments, February 20, 2014, p. 2.

Decision Options

A. Department VOS Methodology

1. Approve the Methodology proposed by the Department, as modified in its February 20, 2014 comments. The three DOC modifications include:

    a. Fuel Price Escalation Factor: 30-day averages are used for the NYMEX Natural Gas Futures contract prices for years 1 through 12; for years beyond year 12, the general escalation rate is used as the guaranteed fuel price escalation.
    b. Avoided Distribution Capacity Cost: set the distribution peak load growth rate based on the utility's estimated future growth over the next 15 years. If the result is zero or negative (before adding solar PV), set the avoided distribution capacity cost to zero.
    c. Allow utilities to select the set of Commission-established non-CO2 externality values most appropriate to their service territory.

2. Modify, with the consent of the Department pursuant to Minn. Stat. §216B.164, subd. 10(e), the Department's Methodology

    (*Staff note: the Department has not indicated any modifications it would consent to, beyond the three included in its February 20, 2014 reply comments*.)

    Potential modifications:

    a. incorporate an economic development benefit adder as a value component
    b. incorporate a market price reduction adder as a value component
    c. incorporate a capacity adder value component for PV system installations with tracking systems or non-standardized system orientation to compensate for demonstrated capacity maximization
    d. incorporate the avoided costs of water consumption and land use ecosystem impacts as a value component
    e. incorporate an SREC compensation value of $0.06 /kWh per SREC as a separate value component or as part of the environmental costs value component
    f. incorporate a compliance value SREC compensation component based on a calculation that would net out the SREC environmental cost value from a standard and/or market proxy price resulting in SREC compliance value[64]
    g. incorporate an SREC benefit adder as a future placeholder
    h. require that PV solar owners on the VOS tariff be given the right to buy-back any SRECs associated with their generation

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[64] Staff believes this proposal by the Environmental Organizations may need to be further explained before it can be adopted. See EO reply comments, p. 10.

i. calculate the avoided fuel cost using the locational marginal price of fuel for each utility
j. calculate the avoided generation capacity cost using the capital cost for combustion turbines only, in place of the weighted capital cost of combustion turbines and combined cycle gas turbines
k. exclude avoided reserve capacity costs as a value component
l. calculate the avoided transmission capacity cost based on current investments plans, reflecting only the cost of future transmission investments that can be avoided
m. calculate the avoided environmental costs using the Commission-established externality values for CO2 rather than the EPA's Social Cost of Carbon (SCC)
n. exclude the Commission-established non-CO2 pollutant values from the calculation of avoided environmental costs
o. reduce the proposed contract term from 25 to 20 years

3. Reject the Department's Methodology.

B. Clarifications on Commission Action

1. Clarify that the Commission's adoption of the Department's methodology or the values contained is not intended to have any precedential effect.

2. Clarify that any updated MNPUC non-externality costs numbers and EPA SCC numbers are to be incorporated into the Methodology.

3. Clarify that the Department must annually update methodologies applied within the VOS Methodology to use best available practices.

4. Take no action.

C. Filing Requirements in a Value of Solar Tariff

1. Direct any utility filing a Value of Solar tariff to include a reporting and evaluation process that occurs prior to the end of the third year of its Value of Solar tariff taking effect.

2. Direct any utility filing a Value of Solar tariff to explain what disclosures it will use to ensure the generator understands it will not own the Renewable Energy Credits, and how these disclosures are consistent with other situations in which the utility owns the RECs.

3. Take no action at this time.

D. Compliance filings

1. Ask the DOC to provide more detail and clarification on its proposal for future placeholders and how and when these will be developed and applied, and the procedure it plans to use for updating the methodologies for calculations within the Methodology, within 60 days of the Order in this matter.

2. Require all investor-owned utilities subject to Minn. Stat. §216B.164, subd. 10, to file for informational purposes, a Value of Solar rate calculated under the Commission-approved Value of Solar Methodology within 30 days of the Order in this matter.

E. Further Actions

1. Direct staff to solicit comments on issues raised by parties that were outside the scope of the notice, such as effect on existing net metered customers, conformity with PURPA, REC ownership disclosure, and any other issues the Commission identifies.

2. Take no action.

216B.164 COGENERATION AND SMALL POWER PRODUCTION

Subd. 10. Alternative tariff; compensation for resource value.

(a) A public utility may apply for commission approval for an alternative tariff that compensates customers through a bill credit mechanism for the value to the utility, its customers, and society for operating distributed solar photovoltaic resources interconnected to the utility system and operated by customers primarily for meeting their own energy needs.

(b) If approved, the alternative tariff shall apply to customers' interconnections occurring after the date of approval. The alternative tariff is in lieu of the applicable rate under subdivisions 3 and 3a.

(c) The commission shall after notice and opportunity for public comment approve the alternative tariff provided the utility has demonstrated the alternative tariff:

(1) appropriately applies the methodology established by the department and approved by the commission under this subdivision;

(2) includes a mechanism to allow recovery of the cost to serve customers receiving the alternative tariff rate;

(3) charges the customer for all electricity consumed by the customer at the applicable rate schedule for sales to that class of customer;

(4) credits the customer for all electricity generated by the solar photovoltaic device at the distributed solar value rate established under this subdivision;

(5) applies the charges and credits in clauses (3) and (4) to a monthly bill that includes a provision so that the unused portion of the credit in any month or billing period shall be carried forward and credited against all charges. In the event that the customer has a positive balance after the 12-month cycle ending on the last day in February, that balance will be eliminated and the credit cycle will restart the following billing period beginning on March 1;

(6) complies with the size limits specified in subdivision 3a;

(7) complies with the interconnection requirements under section 216B.1611; and

(8) complies with the standby charge requirements in subdivision 3a, paragraph (b).

(d) A utility must provide to the customer the meter and any other equipment needed to provide service under the alternative tariff.

(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.

(f) The distributed solar value methodology established by the department must, at a minimum, account for the value of energy and its delivery, generation capacity, transmission capacity, transmission and distribution line losses, and environmental value. The department may, based on known and measurable evidence of the cost or benefit of solar operation to the utility, incorporate other values into the methodology, including credit for locally manufactured or assembled energy systems, systems installed at high-value locations on the distribution grid, or other factors.

(g) The credit for distributed solar value applied to alternative tariffs approved under this section shall represent the present value of the future revenue streams of the value components identified in paragraph (f).

(h) The utility shall recalculate the alternative tariff on an annual cycle, and shall file the recalculated alternative tariff with the commission for approval.

(i) Renewable energy credits for solar energy credited under this subdivision belong to the electric utility providing the credit.

(j) The commission may not authorize a utility to charge an alternative tariff rate that is lower than the utility's applicable retail rate until three years after the commission approves an alternative tariff for the utility.

(k) A utility must enter into a contract with an owner of a solar photovoltaic device receiving an alternative tariff rate under this section that has a term of at least 20 years, unless a shorter term is agreed to by the parties.

(l) An owner of a solar photovoltaic device receiving an alternative tariff rate under this section must be paid the same rate per kilowatt-hour generated each year for the term of the contract.