The Value of Distributed Solar Generation

White Paper

A Report Prepared for NRECA by
Power System Engineering, Inc.

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Value of Solar (VOS) is a proposed technique to measure and value the output of customer-owned distributed solar generation (referred to as distributed photovoltaic, or "distributed PV") to a utility for the purpose of either 1) establishing a VOS tariff used compensating distributed PV or 2) assessing whether a compensation method such as net metering is appropriate. When used as a VOS tariff, utilities would be required to compensate or credit distributed PV owners at rates that reflect benefits that distributed PV may offer to the utility. This could include such straightforward benefits as avoided energy costs, but could also include social or environmental benefits, such as renewable energy credits (RECs), which represent the environmental attributes of the power produced from renewable energy projects.

Similar to feed-in tariffs, the formulation of VOS tariffs can result in increasing the cost of electricity for retail customers by requiring utilities to pay more than their avoided cost and the market REC value. A VOS tariff could require a utility to purchase distributed PV at premium rates when the utility could otherwise have acquired power from an existing hydro resource, a utility-scale wind farm or REC certificate with equivalent environmental attributes at a significantly lower price. It should be noted that several electric cooperatives have standard offers for different types of supply, whether intermittent, dispatchable, locational or REC eligible.

VOS tariffs could also drive up electricity costs for consumers by charging utilities — and thus their customers — for many values not presently being incurred by utilities nor incorporated in current electricity rates. Utilities charge customers for the cost of providing safe, reliable, and affordable power. They do not charge customers for all of the benefits that consumers, the economy, and society in general get from that safe, reliable, and affordable power. Nor do utilities charge customers the value that their other generation resources offer consumers, communities, and the environment. Utilities, for example, do not charge customers more than their cost for nuclear power because it has the benefit of no carbon emissions. Utilities do not charge customers more than their cost for utility-scale solar power because it produces no pollutants. Utilities do not charge more than their cost for coal-fired power to reflect the number of jobs the coal mine and the coal plant provide the community. In effect, a VOS tariff that requires the utility to pay for these types of benefits essentially is requiring the utility to tax (via rates) some of its customers in order to subsidize or benefit others.

Utility retail rate tariffs are generally developed to recover a utility's embedded "cost" of service versus a "value" of service. As such, retail rates recover costs associated with long-term integrated resource planning (IRP) processes which develop the least total cost mix of utility investment options to meet long-term consumer and system needs. Introducing a VOS tariff outside of the integrated resource planning process invalidates the optimized IRP foundation upon which economically efficient resource decisions and thereby retail rates are based. Launching a VOS tariff to address rooftop solar, for example, may be capable of crediting avoided energy costs, but this does not mean it is the optimal sustainable resource option. Community solar and utility solar are generally lower cost resources. Moreover, the long term implications of combining a VOS tariff with ongoing integrated resource planning and retail ratemaking is unclear and needs to be more clearly defined.

Some of our nation's electric cooperatives are located in states that have considered or implemented VOS tariff policies. Moreover, many of these "value", as opposed to "cost", tariffs are being expanded to encompass more than just solar. Cooperatives should monitor publications, state legislation, and ballot initiatives that link other distributed energy resources (DER) into the value mix; i.e., distributed PV and battery storage with "smart," or advanced, inverters. A 2016 white paper by the Analysis Group "The Value of DER to D [distribution]", evaluates how different DER technologies have different attributes and different impacts on and contributions to the electric system. [1]

The electricity sector is complex, and each segment of the grid is affected by every other segment. In order to achieve reliability, affordability, safety and environmental responsibility, the ideal electric system should not promote specific policies or technologies. It should instead strive to achieve the best mix of resources.

America's Electric Cooperatives operate in a unique position in the regulatory policy debate because the majority of them are self-regulated by their local Board. As such, rate setting and regulation is focused upon providing consumers the appropriate information needed to make efficient energy choices, while still accounting for all costs. Elements of the decision making process, while within the purview of the local Board, should be identifiable and transparent. Finally, the rates and regulatory systems should encourage the electric power industry to operate in the most efficient manner possible. Within this framework, locally controlled co-op systems are well-positioned to understand the needs of their consumer-members and the local conditions to be able to balance the equities that occur as part of any rate and regulation setting.

Going forward, it will be important to determine how DER assets can create value across the grid network. New additions to the grid, like solar panels, energy storage, micro grids and distributed system operating functions will require new thinking in terms of how cooperatives recover their revenue requirement and what their consumer-members are paying for different energy services and products.

State policies that pick winners and losers today, such as value-based methodologies for compensating DER, will need to be modified to give consumer centric utilities (CCUs) and their consumers more latitude to optimize investments for the benefit of all consumers. That approach will organically lead to an energy future in which most CCUs provide even greater resource options for households and businesses while continuing to support traditional goals of safety, affordability, reliability, rate stability, and environmental sustainability. Not only do these energy services and system enhancements meet consumer desires, they can be deployed in ways that enhance the resiliency of the electric system.

[1] Reference: http://www.analysisgroup.com/uploadedfiles/content/news_and_events/news/value_of_der_to%20_d.pdf

INTRODUCTION

This white paper discusses how the value of distributed PV is being developed and used in the electric utility industry and how it may apply to electric cooperatives. Various components and approaches used to value distributed PV are presented in an effort to help electric cooperatives evaluate and consider how to best advocate, calculate, and negotiate the value of distributed PV for their cooperative for internal or external purposes.

This topic is of particular interest as it relates to VOS tariffs that have been adopted by utilities such as Austin Municipal Utilities[2] (Austin Energy) in Texas and that have been approved for use by the Minnesota Public Utilities Commission (MPUC).[3] In these cases, the VOS tariff will determine the compensation or credit made by the utility for the solar generation. In other cases, state commissions are using a VOS approach as a benchmark in determining whether its net metering rule or distributed energy resources (DER) compensation policy results in cost-shifting or subsidization.[4] To illustrate how VOS is currently being utilized for these two purposes, two case studies are included at the end of this document: one for Xcel Energy, Inc. in Minnesota, and the other for Central Electric Power Cooperative, Inc. in South Carolina.

Whether used to establish a VOS tariff or as an assessment tool for net metering, the general concept and principles of distributed PV value are the same. Electric cooperatives should be prepared to actively engage in discussions and debates to advocate in the best interest of their cooperative and their consumer-members. Particular emphasis should be placed on consumer-members, ensuring that all users of the cooperative's grid pay appropriately for that use.

BACKGROUND

While net metering of distributed PV allows production to offset consumption with any excess credited or compensated by the utility, a VOS tariff directly compensates the consumer for the full production of the distributed PV facility. In this case, the consumer continues purchasing 100 percent of its electrical needs from the utility; and the utility compensates the consumer for 100 percent of its electrical production from the distributed PV facility. Importantly, the application of a VOS tariff requires the ability to separate a consumer's consumption from distributed PV production; likely requiring dual or separate meters. The VOS tariff governs how this works and in particular sets the rate at which the compensation or credits will occur.

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2 2014 Value of Solar at Austin Energy, Clean Power Research, October 21, 2013.

3 Minnesota Value of Solar (Minnesota VOS Tariff), Clean Power Research, April 1, 2014.

4 For example, if the Value of Solar per kWh to the utility is higher or lower than the retail energy rate per kWh upon which net metering is based, then the net metering scheme could be said to result in a subsidy from or to net metered solar DG customers. An example of this VOS use is the South Carolina Public Service Commission approved valuation methodology in Docket No. 2014-246-E

The details of the VOS method used will determine whether the VOS tariff produces a rate of compensation for solar PV generation that is appropriate (i.e., based on benefits provided to the cooperative and its consumer-members) or one that does not align with the best interest of all cooperative consumer-members.

In this paper, the value of distributed PV is assessed through the lens of the electric cooperative.[5] Value, as it pertains to the electric cooperative and its consumer-members, is the result of costs avoided minus the costs incurred. In this regard, it should be emphasized that an electric cooperative cannot avoid costs it would not have incurred. Similarly, electric cooperatives cannot collect costs from its consumer-members that it would not or does not incur.

The rates charged by an electric cooperative are typically based upon its cost of providing service. The rate that an electric cooperative, and by extension its consumer-members, pay for distributed PV production should be held to the same cost standard, and should reflect only the specific and measurable costs avoided by the distributed PV production. With that said, various stakeholders may advocate for benefits that go beyond calculable avoided cost, and may include various environmental and/or social benefits that are more difficult to quantify. Such advocacy needs to be carefully considered and characterized as benefits that, if accrued, do so to society in general and thus should not be required to be funded by consumer-members via payments in excess of the cooperative's costs avoided by the distributed PV production.

It is vitally important to recognize that avoided costs are subject to the specific situation of each electric cooperative. For example, whether the electric cooperative has access to a centrally-cleared energy and capacity market, or if the avoided costs are created based on internal avoided costs from bilateral energy and capacity markets. These and other factors will have a significant impact on the determination of what costs are avoidable and how they should be quantified. These important characteristics should be incorporated, if available, in lieu of accepting generic or generalized figures or assumptions as might be advocated by distributed PV interests. For example, a G&T cooperative with excess capacity and a strong winter peak at 7:00 p.m. should rightly value distributed PV differently (i.e., less) than a G&T cooperative that is short on capacity with a strong 2:00 p.m. summer peak. In neither case should the cooperative accept a generically assigned or determined capacity value for distributed solar.

Some benefits and costs may change over time or may be contingent upon the technologies being installed and the level of integration achieved. The potential for some grid benefits of distributed PV is strongly correlated to the level of integration and coordination with the cooperative. It may be possible that elusive benefits to the grid could be realized if the cooperative is directly involved coordinating the

5 In its September 2013 report entitled, "A Review of Solar PV Benefit & Cost Studies, 2nd Edition," e-Lab concluded that "There is broad recognition that some benefits and costs may be difficult or impossible to quantify and some accrue to different stakeholders." Reference http://www.rmi.org/Knowledge-Center%2fLibrary%2f2013-13_eLabDERCostValue.

distributed PV installation with regard to location, type of inverters used (i.e., smart inverters), and the integration of other DER resources, such as batteries.[6]

Based upon the components of value identified by Austin Energy and the MPUC, this paper provides perspective on the potential value of those components to electric cooperatives, and specific concepts and methodologies for determining those values. Again, it is cautioned that this is not a one-size-fits-all approach; how a particular cooperative views and evaluates the details will and should be influenced by its own circumstances and member governance. It should be further noted, and is discussed in more detail in this document, that some possible benefits could actually result in increased costs due to a variety of factors.

Below are potential distributed PV benefits and costs included in this paper:

1. Avoided Energy Costs
2. Avoided Plant Operation and Maintenance Expense - Fixed
3. Avoided Capacity Costs
    a. Avoided Generation Capacity Cost
    b. Avoided Reserve Capacity Cost
    c. Avoided Transmission Capacity Cost
    d. Avoided Distribution Capacity Cost
4. Avoided Voltage Control Costs
5. Avoided Environmental Costs
6. Solar Integration Costs

6 Reference http://www.nreca.coop/wp-content/uploads/2013/10/DOESolarRFINRECAcomments.pdf - reply comments of the National Rural Electric Cooperative Association to the U.S. Department of Energy's SunShot Initiative.

1. AVOIDED ENERGY COSTS

The inclusion of avoided energy costs as a component of value is likely to be universally accepted. However, there are a number of options available when determining the value from distributed PV to a utility. At a high level, the value of energy can be determined by at least the following three methods:

1. The operating costs of an established electric generation technology, or Generation Equivalent Approach;
2. The pricing from an electric energy market, or Market Based Approach; and
3. The Production Cost Model Approach.

There are tradeoffs between the various methods in terms of complexity, transparency, flexibility, predictability, and stability. It is also important to understand what is implied by each approach; specifically, how one approach may include other potential benefits so as to avoid double counting. For example, if using the locational marginal price (LMP) from an organized market such as PJM or MISO, the energy price could include more than simply fuel and variable O&M costs. The LMP resulting from the market clearing process would be based on the marginal unit's costs, plus any potential congestion and losses that are specific to a particular location. Thus, when using the LMP to determine the avoided energy cost value, including a separate value for variable production O&M cost avoidance may not be necessary and, in fact, could be inappropriate. On the other hand, when using the generation equivalent approach which considers avoidable fuel, it very well could be appropriate to also include variable O&M so as to account for costs that vary based upon generator output.

Generation Equivalent Approach

Avoided energy costs can be determined by considering the costs of generating electricity from established generation facilities. For example, this would include: *simple cycle combustion turbine (CT)* fueled by either fuel oil or natural gas; *combined cycle*, which is a simple cycle CT typically fueled by natural gas that has a heat recovery steam generator and turbine; and *steam cycle generation*, which is typically fueled by either natural gas or a solid fuel such as coal or biomass. With such an approach, avoided operating costs of these generation technologies are broken into two components, as follows:

1. Cost of the fuel expressed in units of $ per mmBtu (*Avoided Fuel Cost*) and the heat efficiency of the unit, typically expressed in a heat rate curve showing the amount of energy required to operate the unit over a range of generation output levels (Heat Rate).
2. Variable operating costs for the unit, typically called variable operating and maintenance cost (*Avoided Variable O&M*).

<u>Avoided Fuel Costs</u>

The type of unit to be used under the generation equivalent approach should be the unit considered "on the margin" with relation to distributed PV generation. In most cases, this will tend to be natural gas-fired facilities of some type rather than solid fuel or fuel oil. For the purposes of this paper, it is assumed that the generation equivalent approach is based upon a natural gas-fueled facility.

Fuel costs for natural gas are established in the spot market on a daily basis at various trading hubs around the country, and can be financially contracted (i.e., hedged) for longer periods if desired to provide for more price stability. Fuel costs have a transportation cost; for natural gas, the delivered price includes the cost of moving the gas from the trading hub to the location of the generation plant. The price difference associated with the physical transportation of the gas from the trading hub to the generation unit is called "Basis." Transportation costs for coal would typically include rail costs for the unit, unless the plant is located in close proximity to the generation facility. Generation that is fueled by fuel oil has a fuel price specific to the location of the generation facility, and is driven by regional pricing of the product plus a smaller cost of transporting the fuel to the facility. Natural gas is typically purchased on the spot market, which does not include having firm pipeline capacity. For facilities that require a firm capability of producing energy even during times when the pipeline may be interrupted, the capability of burning fuel oil that is stored on-site to maintain power plant operation is sometimes available.

Natural gas prices have varied widely. As recently as 2008, spot prices have reached an extreme of nearly $13 per mmBtu; in more recent pricing, the spot price has remained in the range of $3-4 per mmBtu. By comparison, fuel oil prices are much higher – in the range of $21.70 per mmBtu, whereas coal prices have stayed in the range of $2-4 per mmBtu.

Unfortunately, if longer-term price forecasts are required for evaluating the value of solar, determining long-term avoided fuel costs from natural gas prices can present some challenges, since NYMEX natural gas futures prices do not extend beyond 12 years.[7] To go beyond this would require the utility to either seek a longer-term price quote or to apply an escalator which, of course, could be speculative and should be scrutinized closely. In any case, these spot prices would have to be adjusted by Basis to account for generation location.

The Heat Rate for the generation facility used for calculating the cost can be simplified to one heat rate point; e.g., the unit at the maximum unit output or an average of the operating range. Another approach would be to calculate a cost at varying levels of output, but this is more complicated and involves assumptions as to when the unit would be ramping up and down. Using the 2015 Annual Energy Outlook (AEO) provides new generation characteristics including heat rates for a simple cycle CT unit. The 2015 AEO shows CT heat rates are in the range of 10,500 Btu/kWh. Combined cycle units are more efficient, with the most efficient units recently constructed in the range of 6,300 Btu/kWh, and with a more typical "fleet average" heat rate in the range of 7,000-8,000 Btu/kWh. Steam cycle generation units can vary from 14,000 Btu/kWh for smaller units with steam pressures in the range of 600 lb/in^2; the most efficient units with super-critical steam are in the range of 8,800 Btu/kWh.

[7] NYMEX natural gas future quotes (Henry Hub) are published daily by the CME Group at: http://cmegroup.com/trading/energy/natural-gas/natural-gas.html.

Avoided Plant O&M - Variable

Under the generation equivalent approach, avoided energy costs include variable O&M costs because these costs are incurred for each MWh produced by the generation facility. Variable O&M is based on any consumables used during energy production, such as lime used in scrubbing SO_2, and also a prorated share of costs per MWh based on the projected total cost of a major unit over a prescribed number of operating hours between each major maintenance event. Variable O&M can be volatile and is typically in the range of $12-15 per MWh for gas peaking units, $2-3 per MWh for a combined cycle unit, and $4-6 per MWh for a coal-fired generation unit.

These wide variations occur because each type of generating unit has a typical number of annual operating hours based upon how the generation operating costs align to the total resource portfolio. Typically, larger coal generation units have a high capacity factor in the range of 70-80 percent.

Market Based Approaches

Valuing solar energy using a market-based approach is potentially more straightforward in that pricing data can be gathered and easily independently verified. With that said, it is somewhat more complicated in terms of being able to explain what is driving the pricing and, relatedly, is thus also more difficult to forecast. The type of market used in this valuation can impact the results experienced between utilities and/or regions. There are at least three types of wholesale electric energy markets: 1) over-the-counter bilateral markets (OTC bilateral), 2) trading hub markets (Trading Hub), and centrally dispatched Regional Transmission Organization (RTO) Locational Marginal Price (LMP) markets. Each could be used to establish an avoided energy cost value for distributed PV, and are described in more detail in the following pages.

OTC Bilateral Market

In OTC bilateral markets, buyers and sellers determine the desired energy price and volume based on each party's expectation of the market clearing price. It is typical to transact using block values, with the same MW value of energy for as many hours in a day; the hours are typically broken out as on-peak hours (7 am to 10 pm Monday-Friday) and off-peak hours (balance of hours in the week). Depending on the region where these types of energy transactions are occurring and the firmness of the energy transaction, there may be a need to pursue getting transmission service for the transaction. If the transaction is causing unacceptable loading on the transmission system and doesn't have an adequate level of "firmness", the energy transaction is subject to curtailment. The lack of transmission capacity in an OTC bilateral market results in the transaction being curtailed, rather than using a pricing mechanism to show the increased cost of moving the power across constrained transmission. If the transaction is curtailed, that pricing data should not be included in the pricing history used for valuing distributed PV. Pricing in the OTC bilateral market is unique to each deal, and the discovery of such pricing is not readily available to third parties. Transaction volumes and location also vary which make it difficult to use such a market for establishing avoided energy cost value of distributed PV.

Trading Hub Market

Avoided energy costs could possibly be determined using energy trades occurring within an established trading hub, where marketers have daily on- and off-peak prices established at a specific location on the transmission system. Long before there were RTOs such as MISO and SPP, trading organizations would contract to purchase or sell from a trading hub to allow for wholesale energy purchases to be referenced to a known location. An example of a trading hub that is still being used today is the California Oregon Border (COB). There is an established history of pricing at the trading hub that provides traders with the ability to enter into contracts from this location. Other key market variables (including fuel prices, weather, and monthly variations driven by load) are taken into account when traders establish pricing at the hub and transact on this pricing. As long as the pricing difference from the hub to the load center (i.e., Basis) can be adequately established, this pricing approach could be used to establish an avoided energy cost for distributed PV. Though pricing at the trading hub would have better price transparency than OTC bilateral markets, there might still be issues in that the pricing differential would not be as well established from the trading hub to the load center when determining the value of the energy from a distributed PV facility.

RTO LMP Market

In RTO energy markets such as MISO, PJM, and SPP, the locational marginal price (LMP) is an hourly price for energy comprised of the Marginal Energy Component (MEC), the Marginal Losses Component (MLC) (where appropriate), and the Marginal Congestion Component (MCC) when the system is constrained. The MEC is calculated based on the marginal cost bid of the unit that is on the economic margin for the region, and is the same for all locations within the RTO. The MCC either drives prices up because of the need to dispatch higher priced units within the constrained area, or drives prices down because of too much generation in the area. The MCC is the most volatile component of the LMP and can vary to extreme levels depending on system conditions. The MLC is driven by the MEC and is the more static parameter of the losses in serving the load at each node.

Energy pricing is available in these regions on an hourly basis for both the Day Ahead market and the Real Time market for each generation unit and load at various locations. The energy pricing for the Day Ahead (financial) market is based on generating unit offers and load bids, with a specific transmission system configuration. Any differences between day ahead financial commitments and actual load and generation levels is resolved in the Real Time market, where the impacts of unit outages, variance from the load forecast, or changes in transmission system availability are shown by a price for each node on the system. When transitioning into an RTO LMP market, it generally takes some time for market participants to gain comfort transacting over longer periods of time because the pricing patterns driven by key variables, such as fuel prices, and those driven by load levels are not initially known. Once the market participants are comfortable with longer-term contracts, they are more likely to establish a long-term price projection that could be used for valuing the avoided energy costs.

Energy pricing information in RTO markets is available for all hours, and the pricing reflects the market conditions on a macro level versus isolated transactions. The RTO LMP market approach has the advantage of reflecting the pricing at a relevant location and is both transparent and reliable. A drawback for using an RTO LMP is that it can be difficult to develop a long-term forecast if one is needed to develop a long-term valuation.

Production Cost Model Approach

Utilities typically use power production cost modeling software to simulate the interaction of generation units and the market for serving load and selling excess energy into the wholesale market. The energy value of a distributed PV facility (or fleet) could be evaluated by incorporating the solar hourly load shape into the model and assessing the financial impact on the system costs. The solar energy is essentially set to zero, so the model will show the net impact on the dispatch of generation resources, reduction of energy purchases, or increase of market sales. The assumptions in the power production model are typically updated on a regular enough timeframe to result in a consistent dataset of market prices, fuel prices, operation costs, etc. If the model is set up for a forecasting horizon of 20 years, it could also be used to establish a projection of the avoided energy costs related to distributed PV over those 20 years. It would be useful to show the projection for a number of scenarios of different input assumptions in order to understand the range of values for the solar resource. A utility could use this information to either provide a levelized price for the energy or provide a price that varies by year according to the nominal results shown by the model.

Forecasted vs. Actual Energy Pricing

It is much simpler to use actual, after-the-fact energy price data under either the generation equivalent or market-based approach than to forecast the price. However, price certainty for distributed PV is needed in order to secure project financing. In the Minnesota VOS tariff methodology, a 25-year fixed price approach was established to be calculated annually.[8] Interestingly, in a more recent Xcel Energy application concerning the price to be paid to a community solar garden, the utility and the MPUC agreed to not apply the long-term VOS tariff rate but to apply a slightly higher short-term rate based upon the average retail rate plus an adder for transferred renewable energy credits (RECs).[9]

If required, a projection of avoided energy pricing could be made. One approach would be to establish a fuel price index, a heat rate, variable O&M rate, and annual inflation rate; and then value distributed PV avoided energy per

8 The Minnesota VOS Tariff methodology approved by the MPUC is not required to be filed by electric utilities; however, if a utility does file for a VOS Tariff, it must follow the approved methodology.

9 Reference Minnesota Public Utilities Commission Order in Docket No. E-002/M-13-867 dated September 17, 2014.

these variables and the distributed PV production profile (either unit or fleet level). The projection would need to be made based on the expected "shape" of the distributed PV facility or facilities. Though more difficult, a market price forecast could also be developed to serve as the basis for a long-term avoided energy cost value. When converting into a fixed price contract, the avoided energy costs can be either levelized or escalated per the forecast. However, such long-term contracts have serious risks.

Avoided Energy Cost Summary

The determination of avoided energy costs attributable to distributed PV could utilize 1) the generation equivalent method, 2) a market-based approach, or 3) the results of a power production model. Pricing could either be established based on actual costs or on a projected basis. In terms of market-based approaches, an RTO LMP market would provide the most indicative pricing at the location nearest to the solar generation, compared to more limited OTC bilateral or trading hub markets. If long-term forecasted value is required, utilizing the generation equivalent approach with a long-term fuel and variable O&M forecast may be preferred, although it is also possible, but more difficult, to create an RTO LMP projection for this purpose. Importantly, such long-term forecast values can expose a cooperative to serious downside risks, particularly if solar PV penetration levels increase.

Each of the methods discussed in this section can be considered as a valid means of establishing the energy value for distributed PV depending on the specific situation of the electric cooperative. For easy reference, the following table summarizes the pros and cons of each approach discussed.

Table 1
Comparison of Avoided Energy Cost Methods

Method	Pros	Cons
Generation Equivalent	• Flexible. Can be used as a tool for either forecasting or actual timeframe to establish avoided energy costs. • Nominal effort for setting up model once the type of equivalent resource is determined.	• Using only one type of generation does not provide a dynamic means of reflecting the resource on the margin for each hour of the year. • High dependency on accuracy of fuel forecast of fuel and O&M.
Market - OTC Bilateral	• Clear indication of actual pricing based upon actual transactions.	• Difficult to create OTC forecasts compared to a generation equivalent approach. • Limited price discovery to validate pricing approach. • Volume of transactions may not be representative of market. • Only block pricing available -- not hourly. • Not as applicable in RTO Markets.
Market -Hub Trading	• More established pricing nodes compared to OTC. • Price forecasting is less complicated than nodal pricing for the RTO due to lower number of locations.	• Basis of pricing to actual sources and sinks are difficult to establish. • Forecasts are challenging to create.
Market - RTO LMP	• Clear and established pricing for many locations in an RTO. • Pricing history for nodes is uniform in terms of the method used for determining the pricing.	• No future pricing data provided; only day ahead pricing. • Method of price forecasts is complex and typically involves using a complicated generation dispatch model over a wide geographical range with simplified generation modeling assumptions. • Establishing pricing for so many nodes is more difficult. • Specific locations within load nodes are difficult to price because of the large area of the load nodes.
Production Cost Model Approach	• Full Range of Resources and market cost assumptions included in avoided energy cost assessment. • Production models are built for future years and making financial projections, and can be a good fit for making avoided energy cost projections for solar installations.	• Production Models require a lot of data in order to keep properly updated. • The model needs to be run and understand results based on any and all key assumptions and weaknesses, including the impacts of system constraints, defined transfer limitations etc.

AVOIDED PLANT OPERATION & MAINTENANCE EXPENSE - FIXED

Avoided Plant O&M - Fixed is contrasted to Avoided Plant O&M - Variable. Unlike variable O&M, fixed O&M on generation plants is not a function of plant output, and can only be avoided if plants can actually be deferred or avoided. The inclusion of this component should be subject to the same analysis as the avoided generation capacity cost, which is discussed in more detail in the next section. If distributed PV does in fact allow generation capacity to be avoided or deferred, it follows that related fixed O&M would also be avoided or deferred. Likewise, if distributed PV cannot be determined to avoid or defer generation capacity costs, then neither can there be any fixed O&M costs avoided. Finally, it is important that the basis for determining any avoided generation capacity costs does not already include O&M. This is not likely the case, but a possibility that should be watched for to avoid potential double counting of benefits.

To provide a general range of expectations, fixed O&M for peaking units is estimated to be in the range of $8 to $10 per kW-year, and $11 to $13 per kW-year for a combined cycle unit. This does not include CO_2 capture. Fixed O&M costs for a conventional coal plant are estimated to be $38 per kW-year without a carbon capture and sequestration (CCS) unit, and over $80 per kW-year with the addition of a CCS unit. In converting per kW costs to an energy cost per kWh, the capacity factor of distributed PV must be taken into account, which is discussed in more detail in the next section concerning Avoided Capacity Costs.

AVOIDED CAPACITY COSTS

A critical factor in determining the value of a distributed PV facility is whether or not reducing (e.g., through deferral or avoidance) generation, transmission, or distribution capital investments is possible and appropriate to be considered.[10]

In order to determine the expected value of avoided or deferred capacity costs, if any, the utility must therefore consider: 1) how much distributed PV is expected to be produced in terms of capacity kW during the specific cooperative's annual, seasonal, or monthly peaks (*Avoided Capacity kW*), and 2) the cost of capacity related investments or purchases deferrable or avoidable during the time that the solar PV facility is producing electricity (*Marginal Capacity Cost*). Thus, the general equation is:

[Avoided Capacity kW] x [Marginal Capacity Cost] = [Avoided Capacity Cost]

A somewhat challenging but important issue to address is whether a minimum amount of distributed PV is required to avoid or defer the need for capacity. Realistically, it would take many distributed PV installations to defer a generation, transmission, or distribution capacity investment. A utility cannot necessarily avoid a fraction of a 200 MW peaking resource due to 0.100 MW of distributed PV; i.e., the 0.100 MW of distributed PV in this case, regardless of availability during peak times, is not significant enough to defer or avoid the utility's need for a peaking

[10] The impact and potential for benefit or cost on generation, transmission, and distribution capacity requirements must each be considered separately as each system has its own design and operating criteria. The possibility of benefits on the distribution system, for example, are much more location specific than for generation.

resource.[11] The "lumpiness" of capacity additions may be accounted for in a variety of ways, including applying present value calculations to the marginal cost side of the equation or requiring an aggregate amount of distributed PV to be installed before giving credit for avoided capacity. While this type of adjustment is technically and economically appropriate, it will create the same type of "lumpiness" when it comes to the valuation and potential payment for distributed PV resources, and thus is not likely to be preferred by non-utility stakeholders.

Avoided Generation Capacity Cost

Distributed PV alone is a non-dispatchable and intermittent resource with the potential for substantial variability within the hour and that may or may not be available during peak times. While it is highly unlikely that either one or all distributed PV facilities are producing at their rated capacity during every potential peak of the cooperative, there may be some months and some percentage of distributed PV production that is available on average. The cooperative must determine to what extent the generation capacity of its fleet (or potential fleet) of distributed PV facilities will be producing during the peaks that drive its generation capacity costs. This is not something that a state or the industry in general can determine; rather, each utility needs to determine this for itself.

Avoided Generation Capacity kW

Because generation capacity costs are time-dependent, the distributed PV facility must be capable of producing reliably during the utility's peak hours in order to avoid capacity costs. In order to assess this, it is necessary to acquire or develop hourly production profile data for the distributed PV facility or fleet of facilities. The correlation between the production profile data and the utility's hourly system load, especially when considered over multiple years, will then yield the extent to which distributed PV is available during the utility's peak hours, if at all. This "availability" of a resource to meet the system peak is referred to as its capacity value. It would be expected that, on average, there will be some distributed PV capacity value for a summer peaking utility that peaks during the hours of 2-4 p.m., but possibly not for a utility that is winter peaking that peaks from 6-8 p.m., especially a utility with substantial residential load. Neither should be assumed, however, but should be determined based upon the hourly production profile of the distributed PV facilities and the utility's hourly system load profile.

A basic calculation of capacity value is as follows: if a 10 kW distributed PV facility was producing 4 kW of capacity during the utility system peak, it would be said to have a 40 percent capacity value. Extending this method to a subset of hours during which the highest load occurs and comparing the distributed PV production during these same hours allows for an estimate of capacity value. This is a very straightforward and simple way to estimate the generation capacity avoidance of distributed PV.

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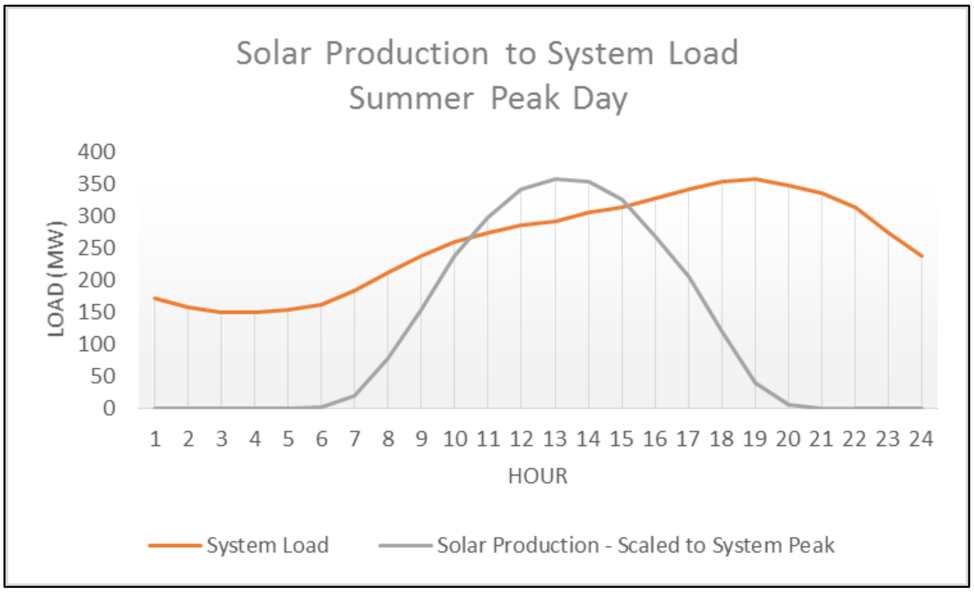
[11] Depending on the capacity supply arrangement, it may be important to monitor the historic and projected system peak demand and available capacity including the projected amount of demand reduction from distributed PV installations. This type of summary would provide the basis for establishing avoided generation capacity costs.

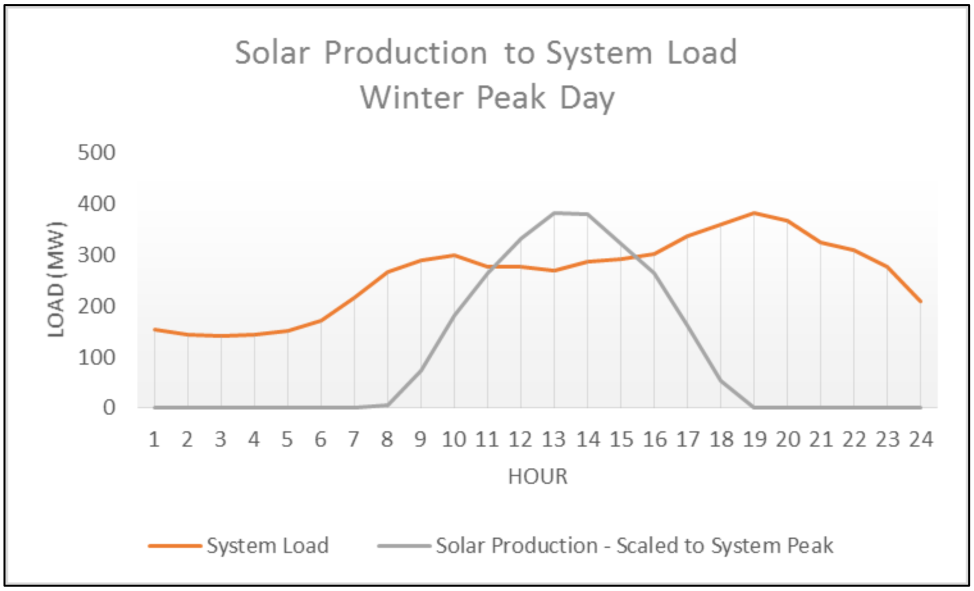
Below are two charts illustrating example outcomes of this method of determination of capacity value. In neither case does the distributed PV production peak at the same time as the system, regardless of whether that system peak is during the summer or winter. However, in Figure 1, solar production is slightly higher during the system peak (i.e., hour ending 19:00) than during the winter system peak in Figure 2 (i.e., hour ending 19:00). It should again be noted that the production curves for solar below represent averages; because solar production is inherently intermittent and non-dispatchable, it may in fact not be available at all at the time of the system peak. That said, diversity of distributed PV installations may help ensure that some production is available at least during mid-day peaks.

Figure 1 Example Correlation of Solar Production and Summer Peaking Utility [12]



12 Solar production load shape reflects data from National Renewable Energy Lab (NREL), PV Watts® for an average July day and scaled to the system peak demand MW. Available at: http://pvwatts.nrel.gov/

Figure 2 Example Correlation of Solar Production and Winter Peaking Utility [13]



The hourly production profile for distributed PV is generally a function of the location, time of year and day, size, and orientation. There are two main types of orientation, with a variety of options under each type: 1) Fixed and 2) Tracking. Fixed arrays stay in the same position; tracking arrays attempt to "follow" the sun. A fixed array is less expensive to install and maintain relative to a tracking system, but tracking arrays offer more watts per installed square foot of unit.

In determining the kW size of a distributed PV facility, it is important to note that PV capacity should be expressed based on AC delivered energy (not DC rated); AC ratings include losses internal to the PV system. A useful equation is:

Rating (kW-AC) = [Module Quantity] x [Module PTC rating (kW)][14] *x [Inverter Efficiency Rating]*[15] *x [Loss Factor]*

There are a few different methods for constructing an hourly production profile such as those shown in the preceding Figures 1 and 2. The first is to meter each unit that is installed. This should be done on an hourly basis for a year. While this is precise, it may be short-sighted or limited in value as it is tethered only to the distributed PV currently installed and interval metered. In addition, the result will be substantially affected by the particular weather and cloud cover for that year. A second option, especially if direct metered data is not available, is to obtain hourly production profile data from an existing comparable unit (or comparable fleet). This should take into account location, system component

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13 *Ibid.* for an average February day and scaled to the system peak demand MW.

14 Module PTC rating as listed by the California Energy Commission (CEC) to account for module de-rate effects. See also Minnesota VOS Tariff p. 13.

15 CEC inverter efficiency ratings are at: http://www.gosolarcalifornia.ca.gov/equipment/inverters.php.

ratings, tilt and azimuth angles, and, if applicable, tracking types.[16] There are several software options available to assist in this estimation.[17] A third approach is to perform ex ante estimates for the expected facilities. The inputs are the same as in the second method, except they will need to be derived from engineering plans and typical meteorological data, not actual installed facilities and observations. Finally, resources such as the National Renewable Energy Lab's (NREL) PV Watts® Calculator can provide transparent and accessible production profiles that could be used at least as a benchmark.[18]

A second option for calculating capacity value is to use "loss of load" probability. A loss of load probability (LOLP) analysis reviews the hours with the highest risk of an outage (as determined by forced outage rates, which generally correspond to periods of highest net load). There are several variations on this method utilizing different parameters, such as the 10 most at-risk hours, the top 1 percent of hours, the top 10 percent of hours, etc. Alternatively, a weighting scheme could be applied to the hours with the higher LOLP. An example of this method comes from the MISO market regarding how wind capacity is credited. In this case, MISO uses the eight highest coincident peaks and determines the capacity value.

A final method that could be used for determining the avoided generation capacity attributable to distributed PV is the Effective Load Carrying Capability Approximation (also known as Garver's method). In order to calculate measures of effective capacity, several different Load-Match Metrics can be used. Examples of these metrics appear in the Minnesota Department of Commerce's "Minnesota Value of Solar: Methodology" report. In this document, two key metrics are developed to capture the diversity of capacity produced by distributed PV units: Effective Load Carrying Capability (ELCC) and Peak Load Reduction (PLR).

ELCC is defined as:

> *[T]he 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.*[19]

For MISO market participants, the coincident peak to the MISO load is very important, as it drives power costs. The current MISO rules for non-wind variable generation are as follows:

> *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*

16 Minnesota VOS Tariff, p. 14.
17 http://www.ncdc.noaa.gov/data-access/land-based-station-data/land-based-datasets/solar-radiation.
18 Reference http://pvwatts.nrel.gov/.
19 Minnesota VOS Tariff, p. 17.

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.[20]

This metric isolates the hours of PV production to determine the capacity that is displaced when the units are running. It should be noted that the ELCC only examines the capacity produced by the PV unit(s) itself; the actual capacity reduction calculation is determined by a separate step. Although the example used here is from the MISO market, this could be easily transferred to another market, such as PJM, or a utility without a market. To do this, the utility simply needs to select a window of hours in which it is most likely to incur its capacity costs. This can be determined by a demand or capacity charge from a wholesale provider, a wholesale contract, a market charge, or the operational dispatch of its units.

In order to determine the capacity reduction from the Effective Load Carrying Capability method, a second metric, Peak Load Reduction (PLR), is used. The Minnesota VOS tariff report provides the following definition:

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.[21]

The above approaches are used to produce an estimate of the avoided generation capacity attributed to distributed PV. The result may be quantified as a capacity value related to the distributed PV output kW (rated or AC) or it may be aggregated to the fleet level based upon the fleet make-up and purpose for the calculation. Regardless, the final step then is to apply the marginal cost of generation capacity as will be described next.

Avoided Cost of Generation Capacity

In addition to establishing the avoided capacity kW as per one of the methods above, the avoided cost per kW must be determined. The avoided cost per kW is often determined based upon the generating unit that a distributed PV facility will be displacing, if any, in the utility resource portfolio during the peak. Given the likely operational profile of PV facilities, it is reasonable to assume that, for

[20] *Ibid.* p. 17. Citing MISO BPM-011, Section 4.2.2.4, page 35.
[21] *Ibid.*

most cooperatives, if a capacity resource is to be avoided, it would be a simple cycle (CT) or combined cycle (CCGT) natural gas generating plant. It should be noted that if these conditions change, the assumption that natural gas is the avoided capacity resource may also change.

Generation Equivalent or "Proxy" Unit Approach

A simple method often used to derive the avoided cost of generation capacity is to use the annual cost of a CT unit per kW. The result of this "proxy unit" method can then be applied to the kW capacity value provided by the solar resource. For example, suppose the avoided cost of a natural gas fueled peaker is $90 per kW year. Further suppose that a 4 kW distributed PV facility is determined to have a 30 percent capacity value. A simplistic calculation would result in avoided generation capacity cost equal to: $90 x (4 kW x 30%), or $108 per year.

The approach of providing an avoided capacity payment based on avoided capacity may appear to ignore the crucial issue specific to each utility of the date for needing additional system capacity. There is a defendable argument to provide an avoided cost of generation capacity. The need for system capacity is a metric that is extremely important when planning for adequate system capacity, but doesn't lend itself to providing a steady pricing signal for the development of renewable resources. The size of the renewable installations is typically orders of magnitude smaller than the amount of capacity projected for a future year. There is a minimum requirement of the number of installations that need to be made in order to provide an amount of capacity that will have any impact on the future capacity need. These installations will typically be made over a number of years, so the accumulative impact of the renewable installations will become more measureable. Using the avoided generation costs of a new generation provides a steady price signal that doesn't ebb and flow around the determination of a system being considered a deficit or a surplus.

Market-Based Pricing Approach

Another approach to determine the avoided cost of capacity is to use market-based capacity prices. This method may be considered for valuing capacity for a cooperative that is commonly using the capacity market as a means of purchasing capacity. One major benefit of this approach is that the pricing is readily available either from a capacity market or from the pricing of bilateral transactions. However, there are several drawbacks to this approach to be considered. First, market prices are only a short-term reflection of capacity value and are often not accurate representations of long-term capacity costs. Market-based capacity pricing will tend to be lower than the avoided generation unit approach for most years, but as the supply reserve margins go down, the market capacity prices will increase. If the reserve margins get too low, the prices could spike, and be higher than the avoided generation unit approach.

Capacity Expansion Model Approach

The last method, which is the most complex and least transparent, is the full-capacity expansion model. These models simulate the optimal generation mix through time by modeling a system dispatch over a study period. They offer the ability to model generation retirement, additional renewables, changing environmental regulations, etc. Due to its system-wide and longer-term view, this method helps to integrate the uneven nature of capacity investments. However, given its complexity and lack of transparency, this method is not often used for determining avoided capacity costs.

G&T and Distribution Cooperative Perspective

A potential complexity that affects many electric cooperatives exists in the electric cooperative business model due to the G&T and distribution cooperatives being separate entities. In the case of generation capacity, a G&T cooperative is most concerned with the peaks that drive its capacity costs and requirements, and the recovery of these costs in an equitable manner from its distribution cooperative member-owners. The G&T cooperative's wholesale capacity or demand charge, along with the other rate components, balances many competing rate design objectives and is not solely intended to provide an accurate price signal for the value of avoiding capacity costs. It is therefore not generally recommended for a distribution cooperative to use the G&T cooperative's or power supplier's capacity charge for the avoided capacity cost. Although an all-requirements distribution cooperative may be inclined to consider the impact of distributed PV on its purchase power capacity billing, it may be more appropriate that this impact be determined according to the G&T cooperative or power supplier system peaks and marginal costs, essentially viewing itself through the lens of the power supply entity. In some instances, this may give rise to the need for the G&T cooperative or power supplier to provide guidance or produce the generation (and transmission) capacity avoided cost value on behalf of its all-requirements distribution cooperative members.

Table 2
Comparison of Avoided Generation Capacity Cost Methods

Method	Pros	Cons
Generation Equivalent/Proxy Unit	• Easily calculated, explained, and justified. • Has often served as basis for avoided capacity costs of other utility programs such as DSM.	• Does not reflect range of resources used to serve load. • Does not account for higher renewable penetration and changes to supply resource dispatching.
Capacity Market	• Easily accessible with price discovery in either bilateral transactions or in capacity markets.	• Difficult to project if long-term value is required. • Reflects short-term value vs. long-term capacity decisions. • Capacity markets vary by year and can escalate drastically during periods of capacity shortfall.
Capacity Expansion Model	• Reflects economies of capacity needs in light of existing and future resource portfolio.	• Complexity and lack of transparency.

Avoided Reserve Capacity Cost

The potential for including avoided reserve capacity cost is based upon the premise that the distributed PV facility is offsetting load requirements such that it would have an impact on the generation reserve capacity requirements. This determination of the reduced generation reserve capacity requirements is dependent on the degree to which the distributed PV facility is reliably producing during the time of the system peaks, if at all.

Regarding the determination of the demand reduction for the Avoided Reserve Capacity Cost that would apply (MW value for each month), the same approach could be used as the avoided generation capacity cost, where a window of 2-4 hours is used for each month to establish the MW contribution from the solar resource. The determination of the avoided generation capacity reserves in terms of $/kW-month will also be used when calculating the applicable Avoided Reserve Capacity Cost. The planning reserve requirements (typically in the range of 12-15 percent) specific to the location of the load is also needed. In summary, the following formula can be used to determine the Avoided Reserve Capacity Cost:

> *Peak Reduction due to Solar (MW) * Avoided generation capacity value ($/MW-month) **
>
> *Planning Reserve Requirement Percent (%) = Monthly Avoided Reserve Capacity Cost*

Avoided Transmission Capacity Cost

There is a consistent method for utilities across the country to pay for transmission facilities. With the advent of FERC Order 888, utilities are required to provide an Open Access Transmission Tariff (OATT) that allows non-discriminatory access to the transmission system. All load-serving parties on the transmission system pay their load ratio share of the annual revenue requirements of the transmission plant. The formula in the OATT uses the historic 12 monthly peaks to determine the billing units to calculate the costs for transmission service. Each transmission customer is charged based on its contribution to each of the 12 monthly peaks. Historic date and time data on the transmission billing peaks is typically available for each party filing an OATT. The average cost data showing both the revenue requirements and the total of the 12 months of peak data is shown in the tariff attachments for each party providing transmission service. The average transmission costs are expressed in $ per kW for each of the 12 months. Each network transmission service customer pays the $ per kW rate for the amount of load that is on the system during the time of the transmission peaks.

While it might seem intuitive to use the previously mentioned $ per kW transmission rate as the potential avoided transmission cost, such an approach does not provide a means of reflecting the avoided transmission costs, if any, due to the addition of distributed PV. As described below, the transmission rate is based upon the average embedded transmission revenue requirement. This represents fixed costs in the existing system that cannot be deferred or avoided. Including these as avoidable costs would only result in shifting them between ratepayers.

<u>Incremental vs. Average Transmission Costs</u>

It is reasonable to question an approach that uses the average transmission revenue requirements as a component in calculating the avoided transmission costs of a distributed PV. The avoided generation energy and capacity components will typically use an incremental approach, and so it would seem reasonable to use an incremental approach for valuing avoided transmission costs. Transmission line additions are justified based on the following main criteria: 1) low and high voltage conditions, 2) thermally overloaded components, 3) system stability concerns, and 4) reducing costs related to transmission congestion as indicated by the congestion component of the LMP. These criteria do not translate well to an incremental capacity kW. The unique transmission metrics of voltage, reactive power requirements, system stability, and reduced congestion are not easily tied to avoided cost units, but they are all required in order to have a reliable transmission system. Each transmission line has a thermal capacity limit, and there are flows that can be attributed to each line. The reduced flow on specific lines due to distributed PV installation(s) is something that technically can be quantified using an alternating current load flow analysis, which must be determined for each distributed PV installation. The difficulty is in defining the incremental transmission $ per kW avoided costs for each of the impacted facilities. It is also difficult to assign the list of facilities required to have adequate voltage support and stability.

Developing avoided transmission capacity costs necessitate an understanding of how the capacity of the transmission system is established. The output from distributed PV is intermittent, and the transmission capacity to serve load is only reduced during times when distributed PV is provided. The combinations of different loading levels as driven by seasonality, time of the day, and the amount of solar generation available are endless. The transmission capacity that is needed cannot be determined by a summarizing a probability distribution of values, but must be determined based on the maximum loading on the system. The maximum transmission loading is likely to occur during a time when the distributed PV generation is not available. With this approach in mind, it would be a logical conclusion that the amount of transmission capacity required to serve the load would essentially be the same whether or not there is any distributed PV on the system. Unlike generation capacity, there is not a diversity of resources available to service load. There is either adequate transmission capacity to serve the load using the specific facilities in the area, or there is not adequate capacity; the most conservative approach needs to be considered when determining the amount of transmission capacity needed.

In conclusion, avoided transmission costs, if any, are extremely difficult to determine due to the complexity of translating meaningful transmission planning metrics such as an acceptable voltage range, thermal limits, and system stability into the metric of avoided capacity kW. The most conservative approach from a supplier's perspective is to assume that the full amount of transmission capacity is the same with or without the distributed PV on the system. The lack of diversity at the system delivery level pushes the level of reliability beyond the realm of statistical distribution representation to the realm of being able to demonstrate adequate transmission capacity in a worst case situation if the distributed PV is not available

Therefore, avoided transmission capacity costs cannot be generally or generically assumed and included in a value of solar tariff.

Avoided Distribution Capacity Cost

Attempts to establish a distribution capacity avoidance benefit for distributed PV tends toward being very complicated if they attempt to isolate the locational nature of potential benefits. Cooperatives should approach the question of whether distributed PV provides distribution capacity avoidance benefits cautiously, especially if such benefits are described generically. Distributed PV has the capability to provide benefits to the distribution system; however, these benefits are site-specific and cannot be generically assigned to all or even most installations. It is imperative that in order to achieve and/or maximize any benefits related to avoiding distribution costs, distributed PV cannot be simply connected but must be integrated with the distribution system.[22]

In order for there to be an avoided distribution capacity cost value from distributed PV, it must be demonstrated that existing costs can be reduced or relieved and/or that future costs can be deferred or avoided. This requires a strong correlation or capacity value between the distributed PV and the distribution feeder peak loading.

[22] Reference *The Integrated Grid Realizing the Full Value of Central and Distributed Energy Resources*, EPRI, February 2014.

However, it cannot necessarily be inferred that correlation with the system peak will result in a distribution capacity cost benefit. The local distribution system (i.e., feeders) is designed-based on factors of loading, voltage, and diversity and, as with transmission, must be reliable even when the sun does not shine. Energy storage equipment could be considered in order to provide a more consistent reduction in distribution loading during times of area peaks. The economics of the distributed PV costs and storage costs could be compared to avoided distribution costs when developing a business case for seeing how distributed PV could reduce distribution costs.

In addition, the costs of interconnecting the distributed PV to the distribution system should be considered either in this component or in an integration cost component. Depending on the location of the distributed PV, there may be a need to build or rebuild a three-phase distribution line from the distributed PV to the point on the distribution system where the system is adequate to support the new generation. Depending on the load in the area and the proximity to the nearest distribution substation, the system needs to be strong enough to handle the generation injection into the system. These interconnection costs for the distributed PV should be itemized above and beyond the base distribution costs, and should not be included in the avoided distribution costs.

Key factors that will affect distribution capacity avoidance benefits derived from distributed PV include:

- The specific characteristics of the utility feeder(s) such as length, size, installed protection, voltage regulating equipment, etc.
- The location of the distributed PV on the feeder.
- The saturation or amount of distributed PV capacity on the feeder compared to the load.
- The amount of other distributed PV connected to the feeder.
- The daily and seasonal load shape compared to the distributed PV load shape.
- The reactive power requirements and flows on the feeder.
- The type(s) of inverters installed with the distributed PV.
- The extent of knowledge the utility has on the specific distributed PV and types connected to its distribution system.
- The capability of the utility to communicate with the distributed PV inverters and dispatch and adjust the real or reactive power.

AVOIDED VOLTAGE CONTROL COSTS

The intermittent characteristic of distributed PV can result in extremely large generation changes hour by hour or minute by minute. The variation in solar generation output is dependent on the solar input and is not something that can be increased during periods when the distributed PV is not available. For this reason, it is not considered reasonable that the solar resource would provide value to the distribution system in providing voltage control cost avoidance. To the contrary, at certain levels of saturation, distributed PV can cause substantial additional voltage control costs.

Voltage control is a term that is broadly defined as the systems on the utility delivery system that are used to maintain voltage levels in an acceptable range.[23] Reactive power is supplied to the system in order to support the voltage along with load-tap changing transformers and/or voltage regulators. Voltage control is provided on both the distribution system and on the transmission level. For purposes of distributed PV, this paper's focus is on voltage control at the distribution level.

Electric cooperative distribution systems are designed to provide acceptable voltage levels to all consumers along the feeder, whether they are the consumer closest or the consumer furthest from the distribution substation. The loading on the feeder from each consumer determines how much the voltage drops with increasing distance from the substation. The voltage control systems at the distribution level are designed to adjust the voltage on the feeder as the load levels vary throughout the year. In theory, a distributed PV facility can improve the voltage profile along a distribution feeder by decreasing the voltage drop when providing power on the distribution line. In such an instance, the distributed PV facility reduces the need for the voltage regulators and capacitors during the time when the distributed PV is providing real and reactive power. However, during times when the distributed PV facility is not providing real and reactive power, there is still the need for the cooperative's voltage control devices to provide sufficient reactive power and voltage support in order to maintain an acceptable voltage profile along the feeder. Conversely, if the output of the distributed PV is greater than the feeder load, voltages may be too high and require the same voltage control equipment to reduce voltage. In these cases, reverse power flow through the equipment is a real possibility and can necessitate retrofitting or replacement of equipment, creating a cost.

If the generation ramp rates of other resources serving load on the system are not adequate to follow the nearly instantaneous changes of distributed PV, the voltage on the system can fluctuate excessively. This can be a concern in areas with high percentages of solar generation compared to the area load. It can also lead to excessive wear on voltage control equipment and lead to increased maintenance costs. A distribution interconnection study can help determine the maximum amount of solar generation that can be interconnected before additional equipment or maintenance is required to maintain power quality. The cooperative cannot generally attribute any voltage control benefits to distributed PV. In fact, as discussed above, there could be additional voltage control costs incurred.

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[23] ANSI C84.1 *Electric Power Systems and Equipment – Voltage Ratings (60 Hertz).*

AVOIDED ENVIRONMENTAL COSTS

While it is certainly true that distributed PV facilities generate electricity without environmental emissions, quantifying this as a benefit from the perspective of the cooperative and its consumer-members is currently challenging. This is an example of a potential area of benefit that is not quantifiable if there is no cost of emissions incurred by the cooperative and/or recovered from the consumer-members that can be avoided.

Resource planning efforts and state commissions have had discussions and proceedings seeking to monetize the impact of reduced emissions. These can be in the form of what are referred to as Externality Costs; i.e., costs that are not directly incurred by the party responsible for the emissions.

This is a difficult and controversial issue around which to gain consensus. There are a number of studies that have been done, and the approach used in the Minnesota VOS tariff discussed using a CO_2 value from a federal study designed to quantify the social cost of carbon (SCC).

These types of studies concerning the SCC are complex and include a wide range of speculative assumptions on what cost impacts increased carbon will have on our environment and society in general. Suffice it to say, by definition a SCC component includes benefits to society in general and goes well beyond cost avoidance benefits to the cooperative and its consumer-members today. In such a situation, if the cooperative were to pay distributed PV consumer-members for societal benefits, it would have to do so from rates or fees assessed to all consumer-members, which is a clear subsidy to distributed PV consumer-members.

In states with Renewable Portfolio Standard (RPS), some stakeholders may recommend that the VOS tariff methodology include environmental benefits based upon the cost of Renewable Energy Certificates (RECs). In such instances, it should be noted that REC markets can be very volatile and it is difficult to value RECs in what is typically desired to be a longer term, stable price. The need for RECs is also very utility specific, and the utility may have already met its RPS by other, less costly means rendering no benefit from distributed PV. Finally, it of course is imperative that were REC values to be included in the methodology then the renewable attributes of the distributed PV generation must transfer to the utility.

While there may be future mechanisms that will enable environmental avoided costs for distributed PV, at this point, it is not clear how the avoided environmental costs could be quantified.

SOLAR INTEGRATION COSTS

The nature of electricity delivery is that the amount of electricity generated exactly matches the amount of electricity used every instant of time. Load and generation are constantly varying, and there must be adequate resources in the supply and delivery system to make sure that the entire grid is kept in balance.

There are a wide range of views on the cost of integrating intermittent renewable energy resources such as distributed PV into the system. The variance in solar generation during periods of cloud cover or changes in weather can produce changes in output that are drastic and require ancillary services associated with keeping the system operating in balance.

Importantly, the potential for integration costs increase with higher distributed PV penetration. With increasing levels of variable generation, the challenge is to determine what specific resources are needed to integrate the solar generation into the system. The issue of what system improvements are needed and who will pay for the improvements is not resolved. For example, if the amount of the solar installation is high enough as a percentage of the load, there is likely a greater need to have generation resources available on the system that can be quickly dispatched to increase or decrease generation levels to keep the system in balance. Because of the intermittency of distributed PV, there may be a need to implement a faster acting electric storage system in order to properly match the change of solar generation. The amount of electric storage capability would be an amount that would result in the operation of the solar resource that would have maximum ramp rates in the range of other conventional generation units on the system, such as a combustion turbine (CT) or an internal combustion engine unit in the range of 10 MW/minute.

In short, distributed PV interconnected and operating in parallel with the utility system is often not the most efficient, cost-effective resource. At high levels of penetration of distributed PV, lower-cost existing generation resources may be displaced or replaced by new fast-ramping resources. Additionally, distribution system costs will increase due to changes in system protection and operation in order to maintain power quality.

Examples of such integration-related issues stemming from a lack of coordination in planning and deploying distributed energy resources (DER) increases are found in EPRI's report entitled, "The Integrated Grid Realizing the Full Value of Central and Distributed Energy Resources," page 13, as follows:

1. Local over-voltage or loading issues on distribution feeders. Most PV installations in Germany (~80%) are connected to low-voltage circuits, where it is not uncommon for the PV capacity to exceed the peak load by three to four times on feeders not designed to accommodate PV. This can create voltage control problems and potential overload of circuit components.
2. Risk of mass disconnection of anticipated PV generation in the event of frequency variation stemming from improper interconnection rules. This could result in system instability and load-shedding events. The same risk also exists from both a physical and cyber security attack.
3. Resource variability and uncertainty have disrupted normal system planning, causing a notable increase in generation re-dispatch events in 2011 and 2012.
4. Lack of stabilizing inertia from large rotating machines that are typical of central power stations has raised a general concern for maintaining the regulated frequency and voltage expected from consumers, as inverter-based generation does not provide the same inertia qualities.

VOS CASE STUDIES

The following are two case studies showing examples of VOS in practice. These case studies provide a means of showing how the VOS methodology is established and how VOS calculations are made in light of a range of available options, including those discussed earlier within this paper.

XCEL ENERGY - MINNESOTA

Xcel Energy is an Investor-Owned Utility operating in multiple states. As required by the Minnesota Public Utility Commission (MPUC or Commission), Xcel Energy filed a VOS calculation as part of its Community Solar Garden filing. The calculation utilized the Commission-approved Value of Solar methodology that was established as per the process described below.

Minn. Stat. § 216B.164, subd. 10(e) required the Minnesota Department of Commerce (Department) to establish a calculation methodology to quantify the value of distributed PV. The Department undertook an extensive stakeholder process involving utilities, trade associations, developers, consultants, renewable community, etc. in the fall of 2013. As expected, various stakeholder groups had concerns that the VOS methodology would produce a result that was either too high, or not high enough to facilitate distributed PV investment without additional incentives. As required, the Department filed its recommended methodology with the MPUC in January 2014; after much deliberation among interested parties, the Commission approved a VOS methodology on April 1, 2014. Public utilities were then authorized to use the approach, on a voluntary basis and subject to Commission approval, to determine a rate of compensation in lieu of net metering (i.e. retail rate) compensation. The VOS methodology approved by the Commission resulted in a 25-year levelized payment for distributed PV.

The following table is the VOS Calculation Table contained as Figure ES-1 in the final Minnesota Value of Solar: Methodology report:[24]

[24] Reference: https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7b7FF17729-DABA-4B96-B37E-3900B5E0D38F%7d&documentTitle=20144-98188-01

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

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

As previously stated, the MN VOS methodology is voluntary at this point with one exception. Due to previously enacted legislation, the Commission directed Xcel Energy to file its VOS to be considered for its proposed Community Solar Garden project.[25] The initial result of Xcel Energy's VOS calculation was a 25-year levelized rate of 14.73 cents and a 2014 rate of 11.34 cents per kWh. However, after correcting for errors identified by the Department, the calculation was revised downward to a levelized rate of 12.08 cents and a 2014 rate of 9.4 cents per kWh.[26] The Commission review of Xcel Energy's VOS rate included evaluating the proposed VOS calculation, consideration of comments from various stakeholders, and review of alternative analysis created by the Department, which mostly confirmed the VOS rate (after correcting for its previously filed comments).

Various stakeholders expressed concern that the result was not adequate to attract subscribers and to secure financing. The stakeholders were nearly split on whether the VOS should be used versus continuing with the average retail rate. After much debate, the final Order from the Commission declined the use of the VOS rate for Xcel Energy's Community Solar Garden project. In its place, the Commission directed Xcel Energy to use the net metering approach based upon the average retail energy rate plus a 2-3 cents per kWh adder for the Renewable Energy Credits

[25] Per 2013 legislation (Minn. Stat. § 216B.1641), Xcel Energy was required to file a plan to operate a community-solar-garden program, under which customers will be able to subscribe to solar generating facilities (known as "community solar gardens," or simply "solar gardens") and receive bill credits for a portion of the energy as established under the VOS statute or applicable retail rate until the VOS rate has been approved.
[26] Docket No. E002/M-113-867. See Reply Comments dated June 19, 2014. https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7bF4F9C68C-A8D7-40CB-B187-43415F4BD63D%7d&documentTitle=20146-100621-01

(RECs).[27] One of the key factors cited in the Order was that any solar installation would require a levelized rate of at least 15 cents per kWh in order to attract subscribers and to secure financing for the project. The result of using the average retail energy rate with a 2-3 cent per kWh adder for RECs is a rate of approximately the targeted 15 cents per kWh.

The Commission Order included a provision to review the March 2015 VOS filing and determine if the updated filing is closer to the 15 cents per kWh "target" rate, for informational purposes only.

Xcel Energy provided an updated VOS filing in March 2015, which is shown in the following table:

Xcel Energy March 2015 VOS				
Component	**Economic Value ($/kWh)**	**Load Match (No Losses)**	**Distributed Loss Savings**	**Distributed PV Value ($/kWh)**
Avoided Fuel Cost	$0.0319		9.8%	$0.0350
Avoided Plant O&M – Fixed	$0.0022	48.6%	10.8%	$0.0012
Avoided Plant O&M – Variable	$0.0028		9.8%	$0.0031
Avoided Gen Capacity Cost	$0.0473	48.6%	10.8%	$0.0255
Avoided Reserve Capacity Cost	$0.0034	48.6%	10.8%	$0.0018
Avoided Trans Capacity Cost	$0.0308	48.6%	10.8%	$0.0166
Avoided Distribution Capacity Cost	$0.0365	55.2%	13.2%	$0.0228
Avoided Environmental Cost	$0.0277		9.8%	$0.0304
Avoided Voltage Control Cost				
Solar Integration Cost				
TOTAL – 25-Year Levelized				$0.1364

[27] Order Approving Solar-Garden Plan with Modifications, dated September 17, 2014 in Docket No. E-002/M-13-867. https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7b10BA0886-4539-4BC2-B896-8E0D8D26E5F4%7d&documentTitle=20149-103114-01

South Carolina – Central Electric Power Cooperative, Inc.

The South Carolina legislature passed S.B. 1189 in April 2014 to create a voluntary Distributed Energy Resource (DER) Program. Though they do not fall under the jurisdiction of this legislation, Central Electric Power Cooperative, Inc. (Central) and the Electric Cooperatives of South Carolina (ECSC) participated with a number of other stakeholders in a joint settlement agreement establishing how the provisions in S.B. 1189 would be met.[28] This settlement agreement was approved by the Commission in March 2015 and received substantial positive media attention.[29] In addition to a number of other net metering-related provisions, the Commission-approved settlement agreement established a valuation methodology for DER. The valuation methodology will be used for determining whether providing a 1-for-1 offset for net metering creates a subsidy to or from DER. Specifically, the difference between the results of the methodology and the 1-for-1 rate will be treated as a DER program expense/credit and may be included in the fuel clause adjustment of the utility.

The settlement DER valuation methodology is described in the table below:

Methodology Component	Description	Calculation Methodology/Value
+/- Avoided Energy	Increase/reduction in variable costs to the Utility from conventional energy sources, i.e. fuel use and power plant operations, associated with the adoption of NEM.	Component is the marginal value of energy derived from production simulation runs per the Utility's most recent Integrated Resource Planning ("IRP") study and/or Public Utility Regulatory Policy Act ("PURPA") Avoided Cost formulation.
+/- Energy Losses/Line Losses	Increase/reduction of electricity losses by the Utility from the points of generation to the points of delivery associated with the adoption of NEM.	Component is the generation, transmission, and distribution loss factors from either the Utility's most recent cost of service study or its approved Tariffs. Average loss factors are more readily available, but marginal loss data is more appropriate and should be used when
+/- Avoided Capacity	Increase/reduction in the fixed costs to the Utility of building and maintaining new conventional generation resources associated with the adoption of NEM.	Component is the forecast of marginal capacity costs derived from the Utility's most recent IRP and/or PURPA Avoided Cost formulation. These capacity costs should be adjusted for the appropriate energy losses.

[28] Central and ECSC petitioned and were granted intervention as interested parties.
[29] Order on Net Metering and Approving Settlement Agreement, dated March 20, 2015 in Docket No. 2014-246-E. https://dms.psc.sc.gov/attachments/order/29CF4369-155D-141F-23B1536C046AEBC5

+/- Ancillary Services	Increase/reduction of the costs of services for the Utility such as operating reserves, voltage control, and frequency regulation needed for grid stability associated with the adoption of NEM.	Component includes the increase/decrease in the cost of each Utility's providing or procurement of services, whether services are based on variable load requirements and/or based on a fixed/static requirement, i.e. determined by an N-1 contingency. It also includes the cost of future NEM technologies like "smart inverters" if such technologies can provide services like VAR support, etc.
+/- T&D Capacity	Increase/reduction of costs to the Utility associated with expanding, replacing and/or upgrading transmission and/or distribution capacity associated with the adoption of NEM.	Marginal T&D distribution costs will need to be determined to expand, replace, and/or upgrade capacity on each Utility's system. Due to the nature of NEM generation, this analysis will be highly locational as some distribution feeders may or may not be aligned with the NEM generation profile although they may be more aligned with the transmission system profile/peak. These capacity costs should be adjusted for the appropriate energy losses.
+/- Avoided Criteria Pollutants	Increase/reduction of SOx, NOx, and PM10 emission costs to the Utility due to increase/reduction in production from the Utility's marginal generating resources associated with the adoption of NEM generation if not already included in the Avoided Energy component.	The costs of these criteria pollutants are most likely already accounted for in the Avoided Energy Component, but, if not, they should be accounted for separately. The Avoided Energy component must specify if these are included.
+/- Avoided CO_2 Emissions Cost	Increase/reduction of CO_2 emissions due to increase/reduction in production from each Utility's marginal generating resources associated with the adoption of NEM generation.	The cost of CO_2 emissions may be included in the Avoided Energy Component, but, if not, they should be accounted for separately. A zero monetary value will be used until state or federal laws or regulations result in an avoidable cost on Utility systems for these emissions.

+/- Fuel Hedge	Increase/reduction in administrative costs to the Utility of locking in future price of fuel associated with the adoption of NEM.	Component includes the increases/decreases in administrative costs of any Utility's current fuel hedging program as a result of NEM adoption and the cost or benefit associated with serving a portion of its load with a resource that has less volatility due to fuel costs than certain fossil fuels. This value does not include commodity gains or losses and may currently be zero.
+/- Utility Integration & Interconnectio n Costs	Increase/reduction of costs borne by each Utility to interconnect and integrate NEM.	Costs can be determined most easily by detailed studies and/or literature reviews that have examined the costs of integration and interconnection associated with the adoption of NEM. Appropriate levels of photovoltaic penetration increases in South Carolina should be included.
+/- Environmenta l Costs	Increase/reduction of environmental compliance and/or system costs to the Utility.	The environmental compliance and/or Utility system costs might be accounted for in the Avoided Energy component, but, if not, should be accounted for separately. The Avoided Energy component must specify if these are included. These environmental compliance and/ or Utility system costs must be quantifiable and not based on estimates.

Using the settlement DER valuation methodology, Power System Engineering, Inc. (PSE) calculated Central's VOS rate. Although the specific values resulting from the analysis are not publically available, the analysis conducted is described below.

Avoided Energy

For the avoided energy category, an hourly shape for a representative solar resource with zero costs was added to the production cost model. The change in the cost of the resource portfolio with and without the resource was used to establish the avoided energy cost value. The production cost model analysis was also used to determine changes in the dispatch of system resources. With regards to other value components, it was determined that the avoided energy charges include existing environmental compliance costs and avoided criteria pollutants such that they were not separately evaluated or quantified.

Avoided System Losses

Energy losses were determined using distribution cooperative-specific average system losses rather than evaluating more granular marginal losses.

Avoided Capacity Costs

For avoided capacity costs, a market-based approach was used. There is adequate cost information available to determine value of capacity, and any capacity requirements were not considered beyond what the market was able to provide. The impacts of reducing the system capacity needs were based on a typical solar profile and the hour of Central's system peak.

Ancillary Services Costs

Ancillary services costs were not considered to be impacted by distributed solar installations on the system. There is some concern that at higher levels of penetration, there may be an increase in the ancillary costs, but at the lower levels of penetration expected in the next few years, the impacts on costs were not expected to be significant and was not easily quantifiable.

Transmission and Distribution Capacity

It was concluded that solar installations are not expected to impact expenditures for either transmission or distribution facilities for purposes of this VOS calculation. Distributed solar production is greatly diminished later in the day when the Central (and its member cooperatives)'s system peaks, plus there is no commitment or guarantee of the solar resource being available. The transmission and distribution systems must be built and maintained in order to meet peak loads under a wide range of conditions, and these conditions include the times when the solar resource is not available.

Avoided CO_2 Costs

There are no defined methods for quantifying the avoided CO_2 costs to Central at this time, and they were therefore not included in the current valuation.

Fuel Hedge

The impact on solar installations on the costs of fuel hedging was assumed to be zero based on discussions with fuel procurement staff at Central.

Utility Integration and Interconnection Costs

The utility will not bear any of the integration or interconnection costs.

The DER valuation methodology established in South Carolina appears to be a very balanced approach that 1) includes essentially all potential areas of cost and benefit, and critically important, 2) requires the ability to quantify costs and benefits relative to the utility and its specific situation. The process of evaluating the VOS for Central has proved to be useful, and it provides a means of showing the impact that solar installations have on system costs, and a possible benchmark for considering future solar RFPs.

CONCLUSION

Value of Solar is a phrase being used by different stakeholders for different purposes. In some cases, it is used in support of the development of a VOS tariff such as with Austin Energy or the Minnesota Commission-approved methodology. In other cases, the determination of VOS is a benchmark or touchstone used to identify whether or not other policies such as net metering provide a proper price signal for distributed PV. In addition, it must be acknowledged that various benefits and costs (from which the "value" is determined) accrued to various stakeholders are not stable throughout time.

The avoided cost components described in this paper include: 1) Avoided Energy Costs, 2) Avoided Plant O&M - Fixed, 3) Avoided Capacity Costs, 4) Avoided Environmental Costs, 5) Avoided Voltage Control Costs, and 6) Solar Integration Costs. The vast majority, if not all, of the potential areas of benefits and costs are found within these categories.

The development of each cost component is specific to each cooperative and should be developed using an approach that is consistent to all members, justifiable based on the assumptions made, and reflective of the current environmental and regulatory environment. This will result in the opportunity to provide an appropriate price signal for new distributed PV development as an alternative to a net metering approach for distributed PV installations.

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