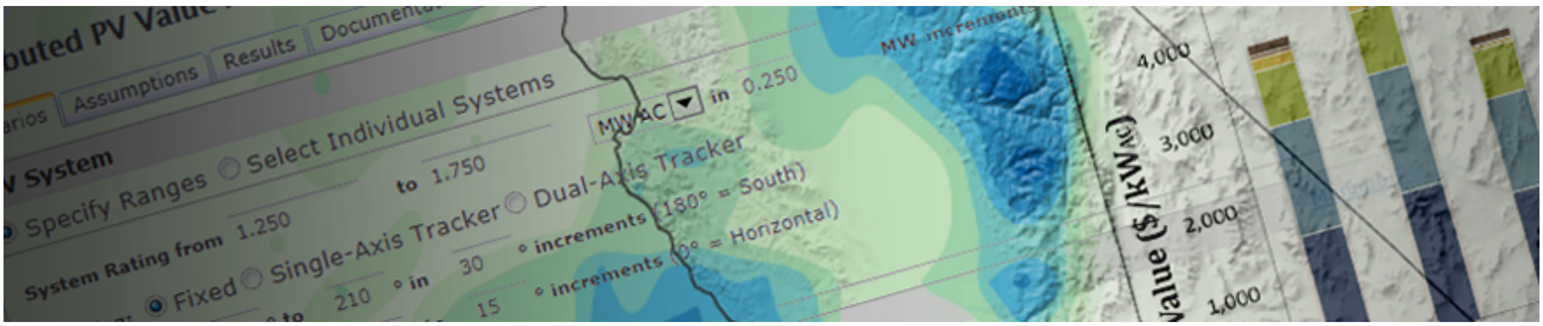
PV Valuation Methodology

Recommendations for

Regulated Utilities in Iowa



February 26, 2016

Prepared for:

Midwest Renewable Energy Association

Prepared by:

Ben Norris, Clean Power Research

Legal Notice from Clean Power Research

This report was prepared for MREA by Clean Power Research (CPR). This report should not be construed as an invitation or inducement to any party to engage or otherwise participate in any transaction, to provide any financing, or to make any investment.

Any information shared with MREA prior to the release of the report is superseded by the Report. CPR owes no duty of care to any third party and none is created by this report. Use of this report, or any information contained therein, by a third party shall be at the risk of such party and constitutes a waiver and release of CPR, its directors, officers, partners, employees and agents by such third party from and against all claims and liability, including, but not limited to, claims for breach of contract, breach of warranty, strict liability, negligence, negligent misrepresentation, and/or otherwise, and liability for special, incidental, indirect, or consequential damages, in connection with such use.

CPR's Solar Valuation Background

CPR holds a unique position in the solar valuation field, having developed the first value of solar tariff offered in North America. Austin Energy approved CPR's value-based pricing presented in a 2011 study, and offered it as a new form of compensation to its solar customers. CPR had performed an earlier valuation study for Austin Energy in 2006.

In 2014, CPR worked with utilities and stakeholders in Minnesota to develop the first detailed, public methodology to be used by utilities in setting rates. This methodology, guided by state legislative requirements, was approved by the Minnesota Public Utilities Commission for utilities seeking a value-based compensation tied to the costs and benefits of distributed solar generation. It is the only such Commission-approved methodology in North America.

In April 2015, CPR published a comprehensive market-based value of solar study that was commissioned by the Maine Public Utilities Commission. This study was also a stakeholder-driven process, and included a wide set of scenarios and assumptions for the purpose of informing public policy. It included three detailed studies for three utility regions.

CPR has performed a number of related studies, including net metering cost/benefit studies and solar fleet shape modeling for Duke Energy, We Energies, Portland General Electric, USD/San Diego Gas and Electric, Solar San Antonio, and NYSERDA/ConEdison. CPR has also worked with solar industry organizations, such as the Solar Electric Power Association (SEPA) and the Solar Energy Industries Association (SEIA) to evaluate other value-based compensation schemes, such as annual versus levelized VOS, long-term inflation-adjusted VOS, value of export energy, and others.

Contents

PART 1 - INTRODUCTION

Introduction

Clean Power Research (CPR) was engaged by the Midwest Renewable Energy Association to develop a methodology for valuing distributed solar energy resources. Many studies have been performed by CPR and others over recent years in which methodologies have been developed to perform these valuations.

Distributed solar differs from conventional generation in several respects. First, it is not dispatchable and therefore requires a means for evaluating its "effective" capacity to put it on a comparable economic footing with in-market resources.

Second, it is distributed, meaning that it avoids the losses associated with long-distance transmission, voltage step down at distribution substations, and the distribution lines. This requires that a loss savings factor be incorporated into the study.

Third, its production profile varies considerably, depending upon the orientation (azimuth and tilt angle) of the system and its location. As a practical approach, the concept of an aggregate "fleet" of resources is introduced to address this, and the valuation is designed to value output of the fleet.

Finally, solar provides a number of societal benefits, such as the ability to produce energy without harmful air emissions and protection against uncertainty in fuel price fluctuations. These benefits are "out of market" in the sense that the societal costs of conventional generation are not included in conventional ratemaking. It is left to the user of the methodology as to whether such benefits should be included in a valuation study.

Purpose

This report describes in general terms a methodology that may be used for such a valuation. For readability, the report is devoid of detailed equations and tables, and it does not include an actual valuation example based on this methodology. However, it does incorporate the lessons learned in a number of such valuation studies performed by CPR over the years.

In addition to the methodology, the report describes some options for implementation. These include the use of the methodology in evaluating existing net energy metering cross-subsidies, considerations for community shared solar, the adaptation of methods for energy exports and other DER technologies, and the use of results in value-based compensation schemes.

It is hoped that such a valuation exercise could be conducted using the methods described here.

Overview of Methodology

The methodology is described in three major parts. The first is a technical analysis where many of the key intermediate technical metrics are calculated. This include the definition of the study period, the rating conventions, the development of hourly fleet production profiles, the determination of "effective" capacity in relation to resource adequacy and the distribution system, and the treatment of loss savings.

The second part is the economic analysis of in-market benefits. This methodology includes avoided energy costs, avoided resource adequacy costs, avoided transmission capacity costs, and avoided distribution costs. It is important to note that this methodology incorporates some benefits that have been broken out as separate categories on other studies. For example, the energy benefit includes the economic impacts of both a change in load and a change in price. The resource adequacy benefit includes the contribution toward meeting both peak load and the planning margin.

Next, two out-of-market benefits are included. These are the benefits most commonly included in studies of this sort, and they include the avoided environmental cost and the fuel price guarantee. These benefits are more speculative and do not represent benefits for which a monetized transaction currently takes place in the energy marketplace.

PART 2 – TECHNICAL ANALYSIS

The Marginal PV Resource

The methodology incorporates in its framework the concept of a "Marginal PV Resource" for which the value of production is sought. Existing solar resources are not included in the analysis except to the extent that they shape the existing loads used in the analysis. It is understood that as the amount of solar in a system increases, the technical contribution towards capacity decreases. This is because the peak load shifts to non-daytime hours. Due to this effect, the initial solar resources (the "early adopters") provide more technical benefits than systems installed in later years (the actual value depends on other factors such as fuel prices and these may increase or decrease).

With this in mind, it is necessary to state up front which of the solar resources are being evaluated: all resources to date? All resources anticipated over the next 20 years? This methodology is based on a marginal analysis of the next PV resource of unit size to come on line.

As described below, a PV Fleet Production Profile is developed that takes into account the diversity of locations and design attributes of the distributed solar fleet. The unit output of this fleet is, in effect, the Marginal PV Resource, even though such a resource does not exist in practice. The concept is helpful because it eliminates a set of complicating value scenarios (What is the value of a west-facing system? a tracking system? a system in the southern or northern part of the service territory?) The Marginal PV Resource therefore is the next installed increment of solar capacity that represents the geographical and design diversity of the distributed PV fleet.

Load Analysis Period and Economic Study Period

There are two separate periods of interest in performing the valuation: the Load Analysis Period and the Economic Study Period. The Load Analysis Period is used to evaluate technical parameters, such as the ability of the resource to deliver energy during peak times. Such analyses require the use of historical, measured data. For example, an evaluation of effective capacity may compare a year of hourly solar production against the same year of utility load. In this case, the Load Analysis Period would be defined as the year over which this technical analysis was based. The analysis could take place over several years (e.g., three years) in order to account for year-to-year load and weather variation.

The second period of interest is the Economic Study Period. This is the period over which the two economic alternatives are evaluated: the production of energy by the Marginal Resource and the delivery of energy using conventional generation. The costs and benefits of these alternatives occur in the future, so the Economic Study Period is selected over one or more future years.

The selection of Economic Study Period is often tied to the final metrics for presenting the benefits and costs, and the assumed useful service life of the resource (e.g., the 20 to 30 year life of solar PV) may be used. For example, if a 25-year service life is assumed, the study objective may be to estimate the levelized value over 25 years. Such an analysis would take into account anticipated capacity additions over this period, expected changes in wholesale energy costs, and load growth rates.

A valuation study may be designed to calculate a one-year, or first-year, value of generation. This is in contrast to a long-term levelized rate. Such an approach offers the advantage of accuracy because it is less dependent on long-term forecasts (e.g., it would require a one-year fuel price forecast rather than a 25-year fuel price forecast). In this case, the investor in renewables takes the risk of future fluctuations in value. Rather than “locking in” a 25-year rate, the rate fluctuations year to year are unknown, and this may be an important factor in the investment decisions.

In the one-year analysis approach, long-term benefits that fall outside of the analysis period, such as the avoidance of future generation capacity additions, may still be included. For example, a future year capacity addition could be included by amortizing the capacity cost of the addition over its expected life, calculating the present value of the annualized avoided costs that occur during the life of the Marginal Resource, and then amortizing this value over the life of the Marginal Resource. This results in the annual value attributed to the present resource in avoiding or deferring the need for future resources.

PV System Rating Convention

The methodology requires the establishment of a rating convention to be used for the Marginal Resource. There are several rating methods available, such as DC power under “Standard Test Conditions,” DC power under “PVUSA Test Conditions” (DC-PTC), and an AC rating that includes the effect of inverter efficiency.

The selection of rating convention is somewhat arbitrary, but must be used consistently. For example, if a DC rating is used, then the Marginal Resource would have a unit rating of 1 kW DC. When determining the annual energy produced, the same convention would be used: annual energy would be expressed as AC energy delivered to the grid per kW DC. Likewise, the effective generation capacity would be expressed as the effective generation capacity per kW DC.

Load Data and PV Fleet Production Profile

The capacity-related technical metrics that follow (see sections on Effective Load Carrying Capability and Peak Load Reduction below) are heavily dependent upon the assumed production profile of the Marginal PV Resource. If there is a good match between solar production and load, then the effective capacity is high. On the other hand, if the peak load occurs during times when solar production is poor, then the effective capacity will be low. This directly affects the economic capacity value.

Before calculating the match, it is necessary to obtain the load data and develop a solar production profile. Both the load and production profile are time series with start and end times corresponding to the Load Analysis Period described above. An hourly interval is most common for studies of this type, although other intervals could be used. MISO pricing is available in hourly intervals, and this will form the basis of the energy valuation. Therefore, hourly intervals are assumed here.

Two sets of load data are required: the MISO system load data and the utility distribution load data. The system load data will be used to calculate effective generation capacity, so the load data should correspond to the MISO zone associated with the utility. The distribution load data will be used to calculate the effective distribution capacity.

In addition, a production profile representing the output of the Marginal Resource is required over the Load Analysis Period. This can be either simulated or measured from sample PV resources, but must accomplish the following:

- The data must accurately reflect the diversity of geographical locations across the utility and the diversity of design orientations (range of azimuth angles and tilt angles, etc.). Typically, this requires the aggregation of several hundred systems comprising a representative “fleet” of solar resources.
- The data must not represent “typical year” conditions, but rather must be taken from the same hours and years as the load data. It must be therefore “time synchronized” with load.
- The gross energy output of the resource is required, not the net export energy which includes on-site consumption.

The fleet comprises a large set of real or anticipated PV systems having varying orientations (different tilt angles and azimuth angles) at a large number of locations. The intention is to calculate costs and benefits for the PV fleet as a whole, rather than for a specific system with specific attributes.

Effective Load Carrying Capability (ELCC)

Distributed solar is not dispatchable in the market, but it does have an indirect effect on the amount of power that is dispatched. If distributed solar produces energy during peak load hours, then the required amount of dispatchable capacity is lowered. Therefore, it is important to quantify how effective distributed solar is in reducing capacity requirements.

Effective Load Carrying Capability (ELCC) is the metric used for this purpose. It is typically expressed as a percentage of rated capacity. For example, if solar is credited with an ELCC of 50%, then a 100 kW solar resource is considered to provide the same effective capacity as a 50 kW dispatchable resource.

MISO is working to develop a process[1] for solar accreditation and several alternatives used at other ISOs are under consideration. When such a process becomes defined, it could be used to calculate ELCC using the PV Fleet Production Profile.

Before the process is developed, it will be necessary to select an interim method, and one such method is described here. This method has been used in other studies by CPR[2] and can be used as an easily implemented method until the MISO process is available.

Under the MISO tariff, Load Serving Entities (LSEs) are required to meet both a local clearing requirement (LCR) in their local resource zone (LRZ) as well as MISO-level planning reserve margin requirement (PRMR). Both of these requirements ensure that reliability meets a 1-day in 10-year loss of load standard. Each of the two requirements is considered separately.

First, the contribution of distributed solar in meeting the LCR requirement is dependent upon the load match of solar production with the zonal load. This could be evaluated as the average of the PV Fleet Production Profile during the peak 100 hours per year in the LRZ. The contribution of these distributed resources not only reduce the required resources to meet the peak zonal load but also reserve requirements. For example, if the average production during the peak 100 hours in the LRZ was 0.5 kWh per hour per kW of rated solar capacity and if the local resource requirement per unit of peak demand was 1.1, then the effective contribution of solar would be 0.5 x 1.1 = 55% of rated capacity.

Second, the contribution of distributed solar in meeting the PRMR requirement is dependent upon the load match with the MISO system load. In this case, the contribution could be calculated by averaging the PV Fleet Production Profile during the peak 100 hours per year in the MISO footprint and applying the planning reserve margin. For example, if the load match

---

[1] See "MISO Solar Capacity Credit" at: https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/SAWG/2015/20150806/20150806%20SAWG%20Item%2007%20Solar%20Capacity%20Credit.pdf

[2] E.g., a 2014 valuation study for the Maine PUC.

was 40% and the margin was 7%, then the effective contribution of solar would be 0.4 x 1.07 = 43% of rated capacity.

Finally, the LSEs may use the same resource to serve both the LCR requirement and the PRMR requirement. The effective capacity, or ELCC, would be selected as the lower of the two results. Continuing the example, if the effective solar capacity was 55% for LCR but only 43% for PRMR purposes, then the overall ELCC would be 43%.

Peak Load Reduction (PLR)

The ELCC is a measure of effective capacity for resource adequacy. It is an essential input to evaluating the benefit of avoided generation capacity costs. However, it is not necessarily a good metric for evaluating avoided transmission and distribution (T&D) capacity benefits for two reasons: (1) it is based on the loads of the MISO zone, rather than the utility's distribution loads (peaks make occur at different times); and (2) it averages output over many hours, whereas distribution planning requires that the resource be there for a small number of peak hours.

Therefore, a different measure of effective capacity can be used in evaluating the distribution benefits. The Peak Load Reduction (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.

Loss Savings Analysis

Distributed solar resources not only displace energy delivered to the load. They also avoid losses in the transmission and distribution lines. To account for this, Loss Savings Factors are calculated and incorporated into the analysis.

Loss Savings Factors depend on the benefit and cost category under evaluation. For example, one Loss Savings Factor could be determined for the avoided energy costs by determining the losses that would be incurred in the absence of PV the solar hours of a given year, and comparing this to the losses that would be incurred during those same hours if the Marginal

Resource were present. The difference could be expressed in a Loss Savings Factor associated with the avoided energy costs.

The Loss Savings Factor associated with avoided distribution capacity costs, however, would be different from the one associated with energy. This is due to two factors. First, as described in the PLR metric, only the peak distribution hours are of interest in calculating the PLR. Avoided losses during non-peak hours (e.g., mid-morning hours) are not relevant to the determination of avoided distribution capacity costs. Second, only the avoided losses in the distribution system are relevant to the distribution benefit calculation. Avoided losses in the transmission system should not be included.

Three Loss Savings Factors should be developed as shown in Table 1.

Table 1. Loss Savings Factors

Loss Savings Factor	Loss Savings Considered
Avoided Annual Energy	Avoided transmission and distribution losses for every hour of the Load Analysis Period.
ELCC	Avoided transmission and distribution losses during the 100 peak hours in each year of the Load Analysis Period.
PLR	Avoided distribution losses (not transmission) at the distribution peak.

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

1. Avoided losses should be calculated on an hourly (not an annual) basis over the Load Analysis Period. This is because solar tends to be correlated with load and losses during high load periods exceed average losses.

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

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

4. Calculations of avoided losses in any hour should take into account the non-linear relationship between losses and load (load-related losses are proportional to the square of the load, assuming constant voltage).

PART 3 – ECONOMIC ANALYSIS

Avoided Energy Costs

Distributed solar reduces the wholesale cost of energy in two respects. First, it reduces the quantity of energy procured in the MISO market for delivery to customers. Solar production displaces energy that would have been procured at a given price in a given hour. Second, it lowers demand for energy, resulting in lower clearing prices for all transactions, an effect sometimes referred to as the “market price response.”

The goal of the valuation analysis is illustrated in Figure 3, which shows the relationship between price and load in a given hour. As load increases (or decreases), the price similarly increases (or decreases). This relationship reflects the supply and demand of resources participating in the market.

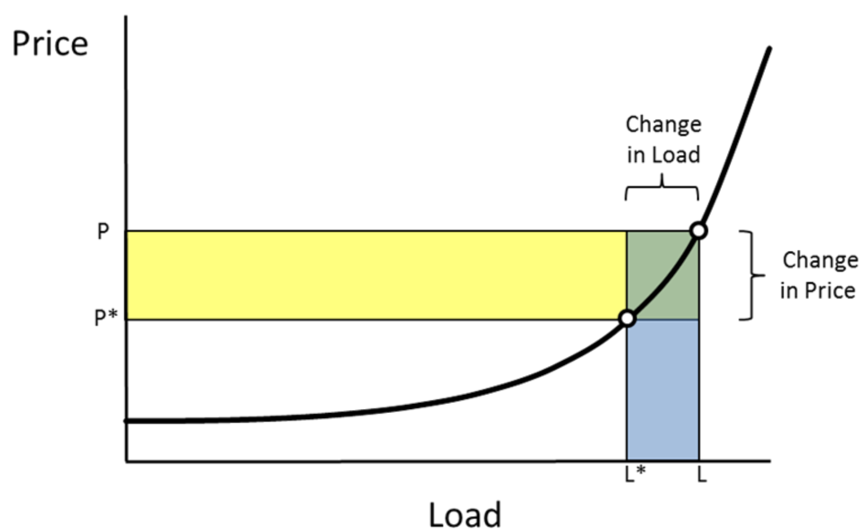


Figure 1. Avoided Energy Cost (Illustrative)

In this illustration L represents the measured load in any given hour, and P represents the corresponding price (the MISO day-ahead clearing price). The Marginal PV Resource reduces load from L to L* and price from P to P*. This reduces the total wholesale cost of energy from LP to L*P* and the savings are represented by the shaded regions.

The calculation of savings may be performed in two steps. The first step is to multiply the observed market price P by the change in load (the blue area). The change in load is the PV fleet production for the hour. This is done for each hour of a sample year and summed.

The second step is to multiply the resulting load L* by the reduction in price. This requires an estimate of the change in price, which may be obtained from a model such as the one illustrated in Figure 2. This shows hourly load-price points for a given month at a sample ISO. From these points a model F may be developed as a least squares curve fit. Then, the analysis can assume that the change in price from P to P* is proportional to the change in F. The calculation is done for each hour of the year and summed.

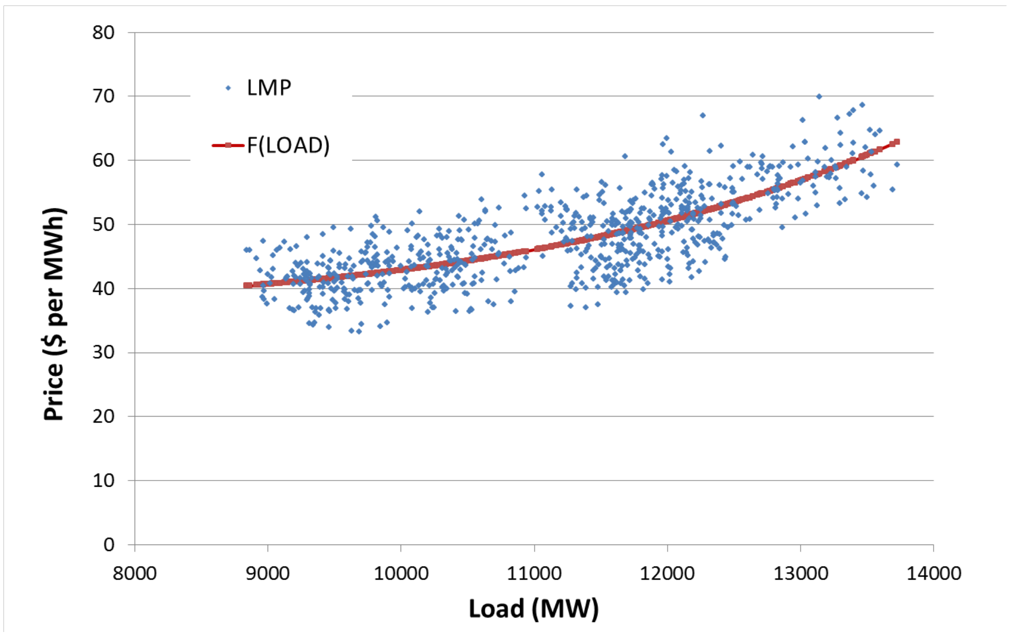


Figure 2. Load Versus Price Model F

Avoided Cost of Resource Adequacy

Part 2 described a method for calculating ELCC, a measure of the effectiveness of distributed solar resources in meeting resource adequacy requirements. The avoided cost, then, is calculated by multiplying the ELCC by the cost of new entry (CONE) for the LRZ. CONE indicates the annualized capital cost of constructing a new plant.

CONE is calculated by MISO[3] by annualizing the net present value (NPV) of the capital cost, long-term O&M costs, insurance and property taxes. There are other measures of capital cost,[4] such as the MISO planning auction, but these do not necessarily correspond to the long-term (e.g., 25 year) service provided by solar.

Voltage Regulation

Distribution utilities have the responsibility to deliver electricity to customers within specified voltage windows as required by State rules. When PV or other distributed generation resources are introduced onto the grid, this can affect line voltages depending upon generator rating, available solar resource, load, line conditions, and other factors. Furthermore, at the distribution level (in contrast to transmission) PV systems are more geographically concentrated. Depending upon concentration and weather variability, PV could cause fluctuations in voltage that would require additional regulation.

In some cases, these effects will require that utilities make modifications to the distribution system (e.g., adding voltage regulation or transformer capacity) to address the technical concerns. For purposes of this methodology, it is assumed that such costs are born by the solar generator. Consequently, no cost is assumed related to interconnection costs.

Advanced Inverters

Advanced inverter technology is available to provide additional services, which may be beneficial to the operation of the distribution system. These inverters can curtail production on demand, source or sink reactive power, and provide voltage and frequency ride through. These functions have already been proven in electric power systems in Europe and may be introduced in the U.S. in the near term once regulatory standards and markets evolve to incorporate them.

Based on these considerations, it is reasonable to expect that at some point in the future, distributed PV may offer additional benefits, and voltage regulation benefits may be included in a future methodology.

Avoided Transmission Capacity Cost

[3] See "Cost of New Entry: PY 2016/17," at: https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/SAWG/2015/20151029/20151029%20SAWG%20Item%2004%20CONE%20PY%202016-2017.pdf

[4] See "Michigan Public Service Commission Solar Working Group – Staff Report" at https://efile.mpsc.state.mi.us/efile/docs/17752/0045.pdf

Distributed PV has the potential to avoid or defer transmission investments, provided that they are made for the purpose of providing capacity, and provided that the solar production is coincident with the peak. The challenge is finding the cost of future transmission that is avoidable or deferrable as a result of distributed generation. As a proxy for this price, transmission tariffs used to recover historical costs may be used.

In the MISO footprint, network transmission service to load is provided under the Open Access Transmission Tariff (OATT) as a per-MW demand charge that is a function of monthly system peaks. Using the PV Fleet Production Profile and the hourly loads of the zone, the average monthly reduction in network load may be calculated for the Marginal PV Resource. For example, the reduction in January network load for a given year would be calculated by first subtracting the PV Fleet Production from load every hour of the month. Then, the peak load for the month without PV is compared to the peak load with PV, and the difference, if any, is considered the reduction in network load for that month. A similar analysis would be performed for the remaining 11 months of the year. For each month, the reduction in peak demand would be multiplied by the zonal network price in the OATT Schedule 9.

Avoided Distribution Capacity Cost

In calculating the avoided distribution cost, the PLR is used as the load match factor. This is multiplied by the NPV of distribution capacity over the Economic Study Period. For example, if the Economic Study Period is 25 years, then the cost of new distribution capacity within the geographical area of interest should be estimated for each year in this period.

Detailed cost estimates are generally available only for areas facing near term capacity upgrades, making it difficult to perform this analysis. Therefore future costs outside the planning horizon may be made based on a projection of costs and peak loads over a representative historical period, such as the last 10 years, and must correspond to anticipated growth rates. Costs for reliability-related purposes should not be included because they are not avoidable by distributed solar.

PART 4 – OUT OF MARKET BENEFITS

Avoided Environmental Cost

With distributed PV, environmental emissions including carbon dioxide (CO_2), sulfur dioxide (SO_2), and nitrous oxides (NOx) may be avoided. In general, it is relatively straightforward to calculate the technical impact—for example, through the use of the Environmental Protection Agency's AVERT tool—but the estimates of avoided social costs are more difficult to quantify.

Estimates of social costs must be taken from external studies. The social cost of carbon, for example, may be based on results from the Interagency Working Group on Social Cost of Carbon.[5]

It should be noted that costs to comply with environmental standards (scrubbers, etc.) are embedded in the energy costs already described. The technical calculations of emissions should therefore already take into account the compliance measures used to reduce emissions. The social costs are therefore associated with the emissions after compliance has been met (the "net" emissions) and the costs are therefore in addition to compliance.

Fuel Price Guarantee

This value accounts for the fuel price volatility of natural gas generation that is not present for solar generation. To put these two generation alternatives on the same footing, the cost that would be incurred to remove the fuel price uncertainty may be included. This can be accomplished by estimating the natural gas displaced by PV over the Economic Study Period and determining the cost of natural gas futures required to eliminate the uncertainty.

Note that price volatility is also mitigated by other sources (wind, nuclear, and hydro). Therefore, the methodology is designed to quantify the hedge associated only with the gas that is displaced by PV.

PART 5 – IMPLEMENTATION OPTIONS

Evaluation of Existing Net Metering Programs

A valuation using the above methods would result in the avoided costs per kWh of distributed solar generation. This valuation could then be used to evaluate the question of whether solar customers under net energy metering (NEM) rates are subsidizing non-solar customers or whether non-solar customers are subsidizing NEM customers.

---

[5] The annual Social Cost of Carbon values are listed in table A1 of the Social Cost of Carbon Technical Support Document, found at: http://www.whitehouse.gov/sites/default/files/omb/assets/inforeg/technical-update-social-cost-of-carbon-for-regulator-impact-analysis.pdf.

NEM customers are only billed (or credited) for the difference between their consumption charges and their generation credits. It has been argued that fixed costs recovered through volumetric rates may not be recovered equitably because NEM customers are able to reduce their monthly net consumption. On the other hand, NEM customers may provide additional benefits, resulting in savings to other customers. For example, a NEM customer may be delivering energy and capacity to the grid at times when it is most valuable. Using the methods described here can help to determine whether cost shifting is taking place and the direction of cost shifting (whether solar customers are subsidizing or being subsidized by non-solar customers, as the case may be).

Considerations for Community Shared Solar

Some customers do not have good options to install solar on their rooftops. They may not own their building (especially in the case of commercial customers), the building may be heavily shaded, or it may not lend itself to solar due to architectural considerations. For these, customers, community shared solar may be an option. Systems built for this purpose may be sited in more desirable locations with good solar access and may be built with higher ratings at lower cost per kW.

However, the methodologies described above may have to be adjusted. There are two factors that must be considered. First, the production profile of these systems will be different than that of the overall fleet as described in Part 2. These systems will be built at optimal orientation (e.g., south facing at an optimal tilt angle) in order to maximize the energy production. Therefore, the production profile associated with such an optimal design should be used rather than the fleet profile.

It should also be noted that the shared solar resource may be electrically distant from the member-customer. In a sense, the energy would have to travel from the shared resource to the customer, and this would include additional losses not accounted for in the methodology. However, the energy in practice would not be delivered to the specific customer but simply accounted for and credited through metering. The energy produced by the resource would still result in avoided losses, except that the losses would be avoided in delivering energy to non-members rather than to the members themselves. The methodology would provide a reasonable accounting of this benefit. Such would not be the case if the shared resource were outside of the service territory of the utility.

Value of Exported Solar Energy

In some studies, the value of export energy is sought rather than the value of gross solar production. This may be the case, for example, in developing a tariff in which self-consumption is used to reduce a customer's electricity bill. Such a rate would effectively provide the customer-generator with two benefit streams: the benefit of lower utility bills due to self-consumption and the benefit of a bill credits associated with the value of export energy. From the utility perspective, such a mechanism also results in two impacts: lost revenue from the self-consumption and lost revenue associated with those bill credits that are exercised.

Regardless of perspective—customer or utility—the economic analysis requires as study inputs the hourly load profile and the relative size of the solar system and the load. This data is necessary to calculate the hourly export profile, and this is a different shape and magnitude than the gross production. If solar generation is self-consumed during the daytime, the mid-day export may be low or non-existent, in contrast to the PV Fleet Production Profile described in this methodology. This means that the capacity value will be different since it is dependent upon the match of between solar and load.

Customers have a choice in sizing their systems. Depending upon size, more or less energy will be delivered to the grid as export energy. Therefore, a study of the export energy value would have to include scenarios that handle these size variations. For example, scenarios could be developed in which solar provides 100%, 75%, 50% and 25% of the annual energy.

Finally, the details of the customer load profile are important. One residential customer, for example, may have a different load profile than another. The export energy profile will therefore be different even if other factors such as system design are the same.

Including multiple scenarios of relative size and profile shape may prove impractical due to the additional technical effort to address each scenario as well as the complexity in determining which result to apply to a given customer. Therefore, the study approach might consider just one or a small number of representative scenarios as an approximation.

Qualifying Facilities Rates

Many of the methods described here could be used to help identify a solar-specific avoided cost rate for qualifying facilities under PURPA. The resulting rate would incorporate many of the solar-specific attributes, such as the hourly production profile, intermittency, and loss savings.

Applicability to Other DER Technologies

Aspects of this methodology may be used for other DER technologies, such as storage and efficiency. However, the PV Fleet Production Profile would have to be replaced with a profile suitable to the technology. For example, energy storage may have a profile that includes off-peak charging and on-peak discharging. If the profile were known, or if they were assumed in a scenario analysis, then the rest of the methodology could be used to calculate the value of these resources.

Real Time Pricing with AMI

In some cases, such as storage (a dispatchable resource), the customer has control of its operation, so the generation profiles may not be known. Value-based rates calculated using an assumed production profile might therefore not be valid for these cases.

If the goal of the valuation is to develop a mechanism for compensation, the methodology may be adapted for use in a technology-neutral value-based rate using real-time pricing. In this case, the DER profile may be determined at the conclusion of the billing month and applied against actual energy prices (e.g., LMPs). In the case of storage, the charging or discharging periods would correspond to energy charges and credits. Capacity value could be fixed for non-dispatchable resources but could require adherence to resource qualification standards similar to the MISO standards and utility control (or penalties for not dispatching during critical peaks).

Value of Solar Tariffs

Value of solar tariffs (or VOST) were introduced by Austin Energy in 2012 and by Hawaiian Electric in 2015. These tariffs intend to provide compensation for solar based on value. Austin Energy, for example, uses a methodology similar to the one described here and incorporating market-based prices in ERCOT. The Hawaiian Electric “grid supply” option provides for self-consumption and a rate for export energy based on marginal energy costs.