ENVIRONMENTAL LAW & POLICY CENTER
Protecting the Midwest's Environment and Natural Heritage

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Commission Staff:

The Environmental Law and Policy Center ("ELPC") and 5 Lakes Energy hereby submit the following comments in response to the Staff Strawman Proposal regarding the methodology for establishing avoided costs under the Public Utility Regulatory Policies Act of 1978, Pub. L. No. 95-617, 92 Stat 3117 ("PURPA").

I. Introduction

On October 27, 2015, the Michigan Public Service Commission ("Commission") issued an order commencing investigation into PURPA and the avoided cost payments that a public utility may be obligated to pay to a Qualifying Facility ("QF").[1] In its Opening Order, the Commission noted that the passage of time and significant changes in the energy industry merited a comprehensive examination of PURPA and avoided cost issues. One of these changes is the increased availability of renewable energy.

By the Commission's order, a Technical Advisory Committee ("TAC") was established consisting of Staff, representatives of electric utilities and electric cooperatives, QFs, small power producers, and advocates. ELPC and 5 Lakes Energy appreciate the opportunity to be involved in the TAC and to provide comments responsive to the straw man proposal created by Staff. The Strawman Proposal includes preliminary avoided cost calculations for five different methodologies: Hydro, Biomass, Landfill Gas, Solar, and Wind. The avoided cost for each of these technologies must be fair and non-discriminatory, which requires an evaluation of the specific characteristics of the type of renewable generation. While ELPC and 5 Lakes Energy's comments support a robust avoided cost methodology for all QFs, we provide specific analysis related to solar and co-generation. ELPC and 5 Lakes Energy have participated in working groups established by the Commission addressing the characteristics of solar generation; these comments are a natural extension of that work. Other participants in the TAC have focused on

[1] Case No. U-17973, Dkt. #1, (Mich. PSC 2015).

the specific attributes of other renewable technologies which should also be given full and careful consideration in establishing avoided cost rates.

II. The Strawman Proposal Methodology Should Be Expanded To Calculate The Utility's Full Avoided Cost, Taking Into Account Technology-Specific Values.

In order to encourage the development of co-generation and small power production facilities, Section 210 of PURPA requires large electric utilities to purchase available energy and capacity from small power producers, known as "qualifying facilities".[2] The Federal Energy Regulatory Commission ("FERC") has delegated to state commissions the responsibility to set rates for purchases from qualifying cogenerators and small power producers by electric utilities under their ratemaking authority.[3] In doing so, FERC stated that it "believe[d] that providing an opportunity for experimentation by the States is more conducive to the development of these difficult rate principles."[4]

PURPA leaves the specific methodology to be used in determining avoided cost to the states' discretion.[5] In Michigan, where the state legislature has not mandated the use of a particular avoided cost methodology, the appropriate methodology is left to the Commission.

PURPA requires that rates for the purchase of energy from QFs not discriminate against qualifying cogenerators or qualifying small power producers and be just and reasonable to the consumers of the electric utility and in the public interest.[6] Under FERC's implementing regulations, upheld by the U.S. Supreme Court in 1983, avoided cost rates are set at the utility's **full avoided cost**.[7] Under these regulations, a utility's full avoided cost is the incremental cost the utility would bear if it were required itself to supply or purchase the electricity produced by the small power producer.[8]

Neither PURPA nor its implementing regulations support the interpretation of avoided cost as the price of energy on the spot market or the short-term marginal cost to the utility of generating one additional unit of electric energy. To the contrary, PURPA encourages states to look beyond the cost of "alternative sources which are instantaneously available to the utility" and evaluate factors such as the reliability of the power and cost savings that could accrue to the

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[2] *See* 16 U.S.C. § 824a-3 (2005); *American Paper Inst. v. Am. Elec. Power Serv. Corp.,* 461 U.S. 402, 405 (1983) ("Section 210 of PURPA was designed to encourage the development of cogeneration and small power production facilities.").

[3] *State ex rel. Utilities Com'n v. North Carolina Power*, 450 S.E.2d 896, 899 (1994); *see also Small Power Production and Cogeneration Facilities Regulations Implementing Section 210 of PURPA* (Order No. 69), 45 Fed. Reg. 12214, 12215 (Feb. 25, 1980).

[4] *Id*. at 12231.

[5] *See California Public Utilities Com'n Order Denying Rehearing*, 134 FERC ¶ 61,044, 61,160 (2011) (granting state commissions the authority to decide what particular capacity is being avoided in setting avoided cost rates).

[6] *See* 16 U.S.C. § 824a-3(b) (2005); 18 C.F.R. § 292.304(a)(1) (2015).

[7] *See American Paper Inst.*, 461 U.S. 402 (1983).

[8] *See Public Service Co. v. Public Utilities Com.*, 687 P.2d 968, 973 (Colo. 1984); 18 C.F.R. § 292.304(b) and (e).

utility in the future.[9] In order to be just and reasonable, the avoided cost rate does not need to be set at the lowest possible rate available.[10]

FERC explicitly sets out those factors that must, to the extent practicable, be taken into account when determining avoided costs. These factors should be evaluated in light of the underlying purpose of PURPA. As the Court explained in *FERC v. Mississippi*, "Congress believed that increased use of these sources of energy would reduce the demand for traditional fossil fuels," and it recognized that electric utilities had traditionally been "reluctant to purchase power from, and to sell power to, the nontraditional facilities."[11] The factors that must be considered are:

> (1) [Utility system cost] data provided pursuant to § 292.302(b), (c), or (d), including State review of any such data;
>
> (2) The availability of capacity or energy from a qualifying facility during the system daily and seasonal peak periods, including:
>
>> (i) The ability of the utility to dispatch the qualifying facility;
>>
>> (ii) The expected or demonstrated reliability of the qualifying facility;
>>
>> (iii) The terms of any contract or other legally enforceable obligation, including the duration of the obligation, termination notice requirement and sanctions for non-compliance;
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>> (iv) The extent to which scheduled outages of the qualifying facility can be usefully coordinated with scheduled outages of the utility's facilities;
>>
>> (v) The usefulness of energy and capacity supplied from a qualifying facility during system emergencies, including its ability to separate its load from its generation;
>>
>> (vi) The individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system; and
>>
>> (vii) The smaller capacity increments and the shorter lead times available with additions of capacity from qualifying facilities; and
>
> (3) The relationship of the availability of energy or capacity from the qualifying facility as derived in paragraph (e)(2) of this section, to the ability of the electric utility to avoid costs, including the deferral of capacity additions and the reduction of fossil fuel use; and
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> (4) The costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from a qualifying facility, if the

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[9] *See Public Service Co.*, 687 P.2d at 973 (Colo. 1984)(citing H.R. Conf. Rep. No. 95-1750, 95th Cong., 2d Sess., reprinted in 1978 U.S.C.C.A.N. 7797, 7832-33).
[10] *See American Paper Inst.*, 461 U.S. 413, 414 (1983).
[11] *FERC v. Mississippi*, 456 U.S. 751 (1982) (footnote omitted).

> purchasing electric utility generated an equivalent amount of energy itself or purchased an equivalent amount of electric energy or capacity.[12]

Commission Staff's Strawman Proposal properly takes into account both energy and capacity impacts on avoided costs on a technology-specific basis. ELPC supports the Strawman Proposal's technology-specific methodology and further notes that a 2010 FERC ruling confirmed that avoided cost rates can differentiate among QFs using various technologies on the basis of the supply characteristics of the different technologies.[13] Avoided cost methodology should differ by technology, because each of the available technologies has different attributes that impact avoided cost in different ways. However, the methodology must be non-discriminatory and result in a full and fair avoided cost rate for each of the different methodologies.

Staff raised a number of additional questions and issues for discussion in the TAC that acknowledge the factors outlined in the FERC implementing regulations. The Commission must now explicitly include each of these factors into technology-specific avoided cost methodology. It is not only practicable to include each of these factors into the avoided cost methodology, but as discussed below, it is the trend in other states that are undertaking similar evaluations of avoided costs under PURPA.

a. Effective Load Carrying Capacity

We appreciate and support Staff's proposal to base capacity value on effective load-carrying capacity (ELCC). This is the appropriate way to determine the effect on firm capacity requirements of resource-limited QFs such as solar, hydropower, and cogeneration. However, we urge staff to recognize that effective load-carrying capacity is potentially facility-specific and technology-dependent. Given a fixed solar array facing south, a fixed solar array facing southwest, a single-axis tracking solar array, and a dual-axis tracking array, each will have a different ELCC. A cogeneration facility that operates whenever the host facility needs process heat will likely have an ELCC that is nameplate capacity less its forced outage rate, which according to Oak Ridge National Laboratory can be as low as 2.5%, while a dispatchable cogeneration facility may also fail to produce due to low spark spread. Thus, while we support use of technology-average ELCC as a starting point in the Commission's methodology, we also urge room for case-specific determination.

With specific respect to solar QFs, we note that the ELCC calculation methods commonly used by utilities and RTOs fail to account for the fact that solar generation is specifically correlated with peak loads because solar heat gain during times of high insolation causes a part of peak loads. Typical averaging methods miss this phenomenon. While we do not expect the Commission to overcome this deficiency and use capacity credits that would not be accepted by regional transmission organizations ("RTOs"), the Commission should understand that it will be undervaluing solar capacity by using these methods.

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[12] 18 C.F.R. § 292.304(e)(1)-(4).

[13] *See* Order Granting Clarification and Dismissing Rehearing, 133 FERC ¶ 61,059 (Oct. 21, 2010).

We further note that if a QF is required to purchase stand-by capacity against the potential that the QF will not be generating at all times, then the QF is effectively providing 100% capacity through the bundle of QF operations and standby power agreements; therefore, the QF should accordingly be credited for said capacity.

b. Avoided Transmission Costs

With respect to all generation technologies, the Commission must include appropriate treatment of avoided transmission costs in its methodology. Michigan regulated electric utilities do not directly own or operate transmission facilities, but purchase transmission services through either the Midcontinent Independent System Operator ("MISO") or PJM Interconnection ("PJM"), pursuant to tariffs adopted by those organizations and approved by FERC. Most costs of transmission are broadly "socialized" within the footprints of these RTOs and are allocated to individual utilities based on the twelve monthly peak hours of power delivery to step-down substations in each utility's service territory. Thus, any QF that is interconnected at sub-transmission voltage and whose power output partially or fully reduces power delivery from the transmission system to such a substation during monthly peak hours directly reduces transmission charges to its utility. This reduction constitutes an avoided cost to the utility, one that the Commission must determine and consider as an avoided cost. The amount of such avoided cost will necessarily be based on the specific circumstances of the QF, but the method of determination can be addressed now by the Commission.

In addition to this basic allocation of transmission costs to utilities, at certain times (not necessarily at monthly peak hours) transmission congestion charges are allocated to a utility when power cannot be delivered to a substation from the least-cost generation resource due to constraints in the transmission system. Specific substations may experience congestion charges at high frequency or in high amounts. These congestion charges are intended to provide a market signal as to the need for additional transmission capacity or alternative resources such as load reduction or distributed generation. A QF that is interconnected through such a substation will reduce such congestion charges, and the Commission must determine either that any avoided congestion charges are an avoided cost to the utility or that any deferred or avoided capacity investments are an avoided cost to the utility. In certain circumstances where transmission congestion, substation capacity, or line length and load prevent the utility from delivering adequate voltage to customers on the same distribution circuits as the QF, the avoided transmission cost may take the form of improved service to those other customers and this should be accounted for as an avoided cost. The amount of such avoided cost will necessarily be based on the specific circumstances of the QF but the method of determination can be addressed now by the Commission.

c. Avoided Line Losses

To the extent that any QF interconnected at sub-transmission voltage serves local load and does not place that power on the transmission system, it avoids line and transformer losses. Thus the value of energy and capacity provided by the QF should each be scaled by the appropriate line-loss factor. The Commission routinely considers and adopts line-loss factors in general rate cases and applies those line-loss factors in power supply cost recovery cases. At minimum, the Commission should use the most recent line-loss study of the relevant utility and make the appropriate adjustments to both energy and capacity avoided costs. It is important to note that the line-loss factors for energy and capacity are distinct and separately determined. We further note that while it is Commission practice to use annual average line-loss factors in adjusting energy costs, actual physical losses are the sum of some losses in transformers and similar equipment that are constant with respect to current and a substantial majority of actual physical losses that are proportional to the square of current. Consequently, any marginal reduction of load due to distributed generation reduces losses equal to nearly twice the proportional reduction in load. Thus, if the Commission only applies the line-loss factors determined in its rate cases, it will systematically understate the avoided costs of distributed generation.

d. Hedging Value

Solar and other distributed generation provided through long-term QF contracts at a fixed price or price schedule also acts as a hedging mechanism, reducing a utility's fuel price uncertainty. This hedge has real value and should be included in avoided costs. The standard method to value such a hedge is to determine the levelized cost of the contracted power to the utility using a zero-risk discount rate, for which US treasury inflation-protected securities are normally the proxy. If the contract is indexed to a macroeconomic measure, such as general inflation, then the discount rate used in the levelized cost calculation should be adjusted for the index. For example, if the contract is indexed to inflation then the discount rate should be based on (non-inflation-protected) US treasury securities.

e. Avoided Emissions and Environmental Compliance Costs

Utilities should also include avoided carbon costs and other emissions allowances in the calculation of avoided energy costs. While environmental considerations are not included in FERC's regulations, planning numbers associated with regulation of greenhouse gas emissions reflect imminently real, non-zero, costs. While there are challenges to quantifying this benefit, the value should not be set at zero. Unless such costs are quantified and included in the avoided costs on which a QF's contract is based, then the value of any such future avoided costs to the utility should accrue to the QF at such time as regulatory changes cause such costs to be manifest. Some care is needed on this point, as some environmental benefits, such as renewable energy credits, can accrue to the QF in the ordinary course of regulation. But others, such as avoidance of emissions allowances by utility generation, may accrue to the utility in the ordinary course of regulation.

III. The Commission Should Consider a Value of Solar Analysis to Help Establish Avoided Costs for Distributed Solar Resources in Michigan.

States and utilities are undertaking increasingly sophisticated evaluations of the true avoided cost of solar. These evaluations not only acknowledge the factors FERC requires be considered in determining avoided costs, but also demonstrate the feasibility of incorporating these factors into an avoided cost methodology that captures the full, technology-specific avoided costs of solar PV. Staff's 2014 Solar Working Group report discussed several programs that have attempted to establish a fair "value of solar" ("VOS") rate based on avoided utility costs, including the Austin Energy VOS Program, the Minnesota VOS methodology, a dynamic pricing program proposed by 5 Lakes Energy, and a Michigan-specific white paper developed by the National Renewable Energy Lab (NREL).[14] The Solar Energy Industries Association (SEIA) maintains a webpage with links to more than 30 other recent solar cost-benefit studies.[15]

Although the details vary, the benefits and costs studied in VOS analysis generally fall into the following categories: energy (including line-losses), capacity (both generation capacity and transmission and distribution capacity), grid support services (also referred to as ancillary services), financial risk (fuel price hedging and market price response), security risk (reliability and resilience), environmental benefits (carbon emissions, criteria air pollutants, and others) and social benefits. Many of these values relate to solar generation's innate characteristics – its natural coincidence with peak demand; its ability to avoid transmission capacity costs and line-losses by siting smaller systems on the distribution grid closer to load; its scalability; its lack of fuel volatility; and other characteristics.

The growing body of VOS analysis consistently demonstrates that solar energy has value that significantly exceeds more narrowly calculated avoided costs. While not every factor can be quantified precisely, a VOS analysis generally provides a more accurate estimate of the "full avoided costs" associated with solar generation over the life of the solar generation system. Thus, several states and utilities have established or are considering the use of a VOS analysis to establish a technology-specific avoided cost under PURPA that explicitly accounts for the unique values of distributed solar PV.[16]

The firm Clean Power Research (CPR) has conducted a number of comprehensive market-based VOS studies that have been used by a number of states and utilities to help inform program and tariff design. CPR has just completed a new report that describes a proposed methodology and other recommendations for valuing distributed solar energy resources in Michigan.[17] The report concludes that a properly-designed VOS analysis could be used to establish a technology-specific avoided cost for distributed PV resources in Michigan. The Commission should carefully consider this report, as well as the other VOS analyses performed for other states and utilities in order to develop a technology-specific rate that fairly reflects the "full avoided costs" associated with solar generation.

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[14] *See* Michigan Public Service Commission, *Solar Working Group – Staff Report* (June 30, 2014) *available at* http://efile.mpsc.state.mi.us/efile/docs/17302/0106.pdf. (The MPSC's Solar Working Group website also includes links to other value of solar (VOS) resources and documents. The website is available at the following link: http://www.michigan.gov/mpsc/0,4639,7-159-16393_55246_55249-321593--,00.html).

[15] *See* SEIA, Distributed Solar Cost-Benefit Studies, http://www.seia.org/policy/distributed-solar/solar-cost-benefit-studies (last visited Feb. 24, 2016).

[16] For example, Georgia Power recently filed a new VOS framework that it intends to "serve as the basis for new avoided cost calculations, renewable program development, project evaluation, and rate design." *See* Georgia Public Service Commission, Docket 40161 (Georgia Power Company's 2016 Integrated Resource Plan) at 10-103.

[17] Clean Power Research, *PV Valuation Methology, Recommendations for Regulated Utilities in Michigan* (February 2016) (attached as Exhibit 1).

IV. The Commission Should Consider Expanding the Availability of Standard Rates For Purchases to Further the Purposes and Objectives of PURPA.

In addition to creating an avoided cost methodology that encourages cogeneration and small power production facilities, the Commission must also evaluate the framework under which energy and capacity are provided by QFs. This framework must include the availability of standard rates to QFs that reduce transaction costs and are of sufficient length to provide certainty regarding financing. Long-term contracts enable investors to calculate return on investment with certainty and instill confidence that the borrower will be in a position to repay any loan extended. With increased price certainty for a project, investors typically require a lower return, which, in turn, reduces the cost of financing. Unlike the electric utilities to which they provide energy and capacity, a QF is not guaranteed a rate of return on its activities. Without some continuity and certainty, QFs are placed in a position of considerable risk in proceeding forward in a cogeneration or small power production enterprise.

The establishment of standard rates under PURPA provides the certainty necessary to encourage development of cogeneration and small power production facilities. PURPA regulations require electric utilities to establish standard rates for purchases from QFs with capacity of 100 kilowatts ("kW") or less, and give state commissions the authority to develop standard rates for larger QFs.[18] In contrast to an individualized rate, a standard rate is the avoided cost rate that would apply to any QF eligible for that rate that provides energy or capacity to the utility. The availability of a standard rate reduces transaction costs for individual QFs, avoiding the cost and burden of establishing an individualized avoided cost rate and reducing barriers to entry. Although standard rates do not differentiate among individual QFs, they can be technology-specific and "differentiate among qualifying facilities using various technologies on the basis of the supply characteristics of the different technologies."[19]

Standard rates allow QFs to create a legally enforceable obligation on the part of the utility to purchase energy and capacity. Under a standard rate for purchases, a QF has the option to either provide energy "as available" or to provide energy or capacity pursuant to a legally enforceable obligation.[20] If the QF chooses to sell pursuant to a legally enforceable obligation, it has the express right to choose a rate based on either the avoided costs calculated at the time of delivery, or the avoided costs calculated at the time the obligation is incurred.[21] FERC established this legally enforceable obligation in order to reconcile the requirement that rates for purchases equal avoided costs with the need for QFs to enter into contractual commitments based on estimates of future avoided costs. In promulgating regulations, FERC agreed with comments stressing the need for certainty with regard to return on investment in new technologies.[22] Standard rates are essential for small QFs to obtain financing. FERC acknowledged that "in order to be able to evaluate the financial feasibility of a cogeneration or small power production

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[18] 18 C.F.R. § 292.304(c)(1), (2).
[19] *Id*. at 292.304(c)(3)(ii).
[20] *Id*. at 292.304(d).
[21] *Id*.
[22] 45 Fed. Reg. 12224 (1980).

facility, an investor needs to be able to estimate, with reasonable certainty, the expected return on a potential investment before construction of a facility."[23]

The mechanism is framed as a "legally enforceable obligation" in order to prevent utilities from circumventing the requirement that provides capacity credit for a QF simply by refusing to enter into a contract.[24] Intermittent QF resources, including solar, can enable a utility to avoid capacity, and the aggregate capacity value of such facilities must be considered in the calculation of rates for purchases.[25]

Michigan should establish standard rates for QFs with generating capacity above 100 kW because it will further the purposes of PURPA by promoting growth of cogeneration and small power production facilities. In fact, the FERC gave states the discretion to establish standard rates for larger QFs **precisely because** standard rates significantly encourage cogeneration and small power production.[26] Other states have recognized the benefit of extending the standard rate to larger QFs. In upholding the propriety of continuing to offer standard rate contracts to QF's under 5MW, the North Carolina Utilities Commission considered Public Staff testimony that:

> . . . setting the standard threshold at a [5 MW] level that allows QFs to receive the benefit of reduced transaction costs and appropriate economies of scale provides ratepayers with the assurance that the utilities' resource needs are being met by the lowest cost options that may be available.[27]

Extending standard rates for larger QFs in Michigan will not only serve the purposes of encouraging the growth of cogeneration and small power production facilities, it will benefit ratepayers by providing them with the lowest cost option to meet resource needs.

The Commission should offer standard rates with conditions that are conducive to growth of cogeneration and small power production. Specifically, the Commission should require utilities to offer long-term levelized capacity payments and energy payments for a variety of terms, including terms long enough to provide a QF with sufficient certainty to obtain financing for and undertake capital expenditures.

Although the issue of standard rates has not been a primary focus of the TAC meetings, it should be addressed in the Staff report and considered by the Commission as an important part of the PURPA avoided cost framework. It is essential that both the avoided cost methodology and the mechanism by which QFs access avoided costs be fair, non-discriminatory, and promote development of cogeneration and small power production facilities.

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[23] *Id*. at 12218.
[24] *Id*. at 12224.
[25] *See JD Wind 1, LLC*, 130 FERC ¶ 61,127 (2010) ("[FERC] always intended that nonfirm, intermittent QF resources are included in the phrase 'each qualifying facility' that has the option to choose to sell pursuant to a legally enforceable obligation.").
[26] 45 Fed. Reg. 12223 (1980).
[27] *See* Order Setting Avoided Cost Input Parameters, Docket No. E-100, SUB 140, (North Carolina Utilities Commission, Dec. 31, 2014).

V. Conclusion

The Staff straw man proposal's preliminary estimate of technology-based avoided costs is a solid start towards developing an updated avoided cost methodology in Michigan. The proposed methodology should be expanded to account for the utility's full avoided cost, taking into account all of the factors FERC has directed states to evaluate. Evaluation of factors such as ELCC, transmission costs, hedging value, and avoided emissions is not only practicable, it is essential to developing technology-specific avoided cost rates that are fair and non-discriminatory. Staff should not lose sight of other important attributes of avoided cost, and should support standard rates that are available to QFs over 100 kW and that can be incorporated into legally enforceable obligations of sufficient duration to allow QFs to obtain appropriate financing. Michigan should join the other states and utilities undertaking these comprehensive analyses, the result of which will be a more robust avoided cost methodology that furthers the goals of PURPA.

Respectfully submitted,

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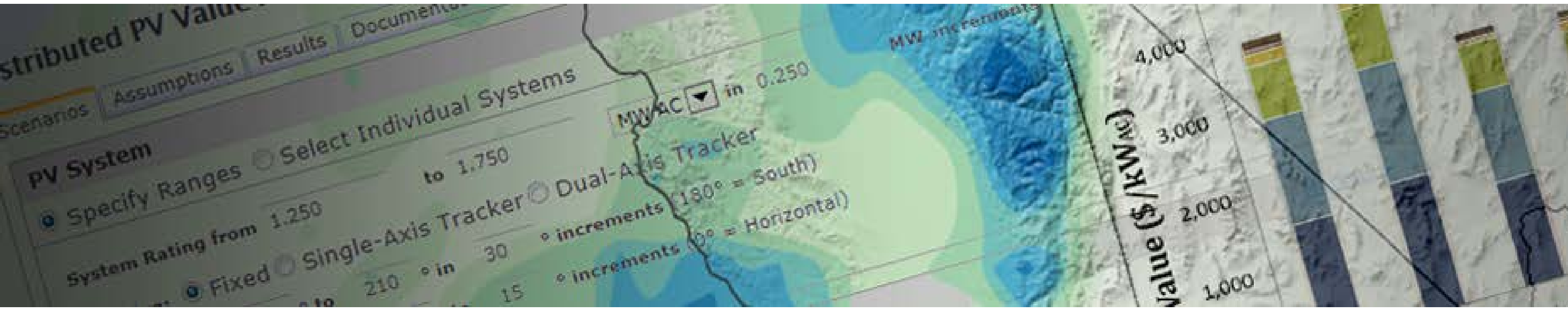
Exhibit 1

PV Valuation Methodology

Recommendations for

Regulated Utilities in Michigan



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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 to 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.

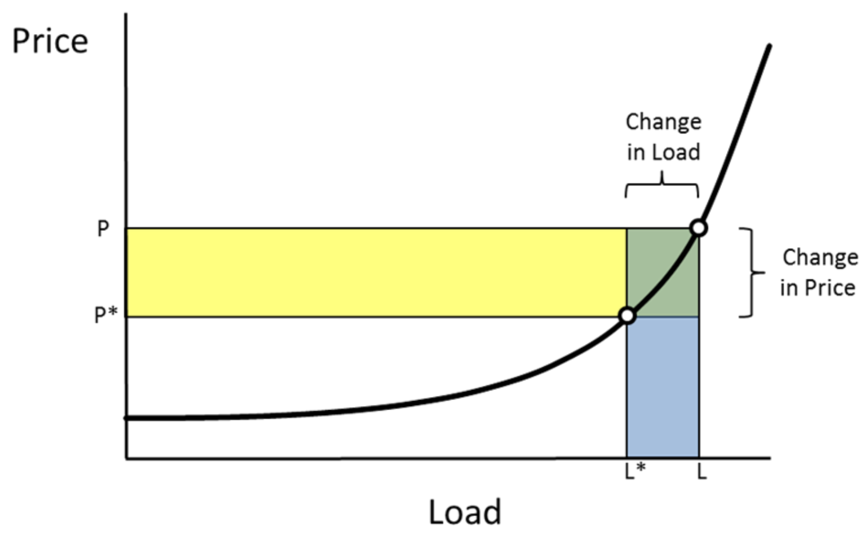

Figure 1. Avoided Energy Cost (Illustrative)

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.

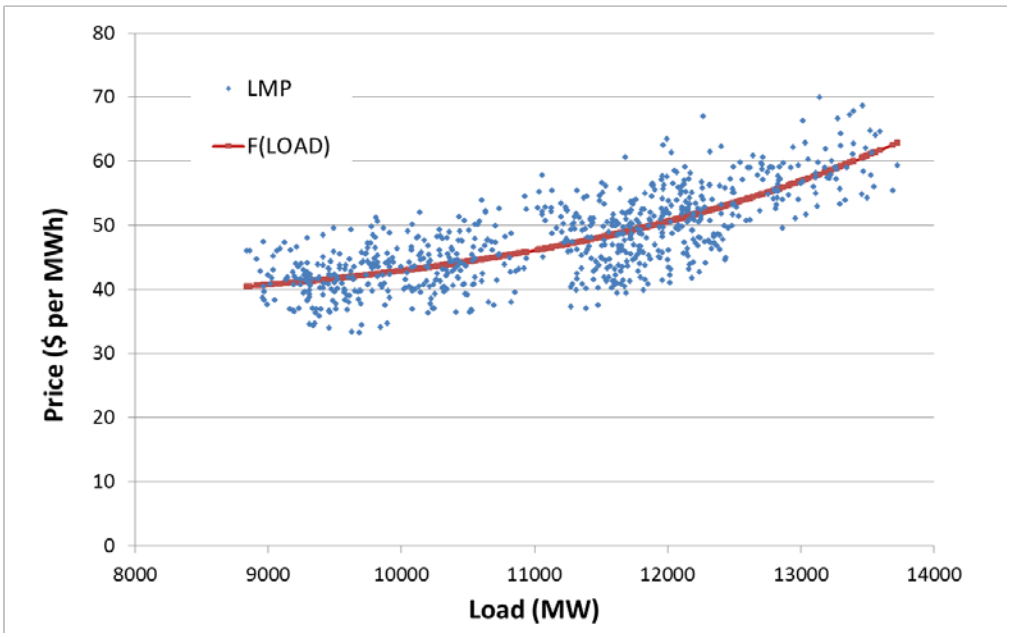

Figure 2. Load Versus Price Model F

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.

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[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

Avoided Transmission Capacity Cost

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 (CO2), sulfur dioxide (SO2), 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

[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.

customers under net energy metering (NEM) rates are subsidizing non-solar customers or whether non-solar customers are subsidizing NEM customers.

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.