PGE Distributed Solar Valuation Methodology

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Executive Summary

This report lays out a methodology to calculate the avoided costs that result from distributed solar production delivered to the Portland General Electric (PGE) electric distribution system.

The methodology is concerned primarily with the benefits and costs of distributed solar generation, but can also be modified for use with utility scale resources (connected to transmission) by eliminating the avoided transmission and distribution costs benefits and removing the loss savings. Furthermore, the methodology can be used for other generation technologies other than solar, but it does not include dispatch strategies or other methods to produce an assumed generation profile (the profile is an input to the methodology).

The overall methodology is summarized in Figure ES-1 in which the benefit and cost categories are listed along with applicable load match factors and loss savings factors to arrive at the final value. For example, the Avoided Generation Capacity Cost is developed initially for a “perfect” (i.e., fully dispatchable) resource, and then a factor for the effective capacity (EC) is applied to account for the non-dispatchable nature of the resource. Finally a loss savings factor is applied since the resource is located adjacent to the load. Note that three different loss savings factors are employed, depending upon category. For example, the loss savings factor associated with Avoided Energy Cost (“LSF-Energy”) differs from the loss savings factor associated with effective capacity (“LSF-EC”). LSF-Energy would incorporate loss savings in all solar hours, while LSF-EC would be heavily weighted by the relatively few peak hours, depending upon the method selected for EC.

The method for calculating each component cost and benefit is described in this document, along with supporting methods, such as those needed to produce the underlying solar profiles and the method for calculating load match factors and loss savings factors.

Figure ES-1. Summary of Methodology

Levelized Value			Gross Value A ($/kWh)	×	Load Match Factor B (%)	×	Loss Savings Factor (1+C) (%)	=	Distributed PV Value D ($/kWh)
Energy Supply		Avoided Fuel Cost	C1				LSF-Energy		V1
		Avoided Variable O&M Cost	C2				LSF-Energy		V2
		Avoided Fixed O&M Cost	C3		EC		LSF-EC		V3
		Avoided Gen. Capacity Cost	C4		EC		LSF-EC		V4
		(Solar Integration Cost)	(C5)				LSF-Energy		(V5)
Transmission and Distribution		Avoided Trans. Capacity Cost	C6		EC		LSF-EC		V6
		Avoided Dist. Capacity Cost	C7		PLR		LSF-Dist		V7
		Voltage Regulation	C8						V8
Environmental		Avoided Environmental Compliance	C9				LSF-Energy		V9
		Avoided SO_2 Emissions	C10				LSF-Energy		V10
Customer		Avoided Fuel Price Uncertainty	C11				LSF-Energy		V11
									Total

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Introduction

Overview

This report lays out a proposed methodology to calculate the avoided costs that result from distributed solar production delivered to the Portland General Electric (PGE) electric distribution system.

Distributed PV versus Utility Scale PV

The methodology presented here incorporates many techniques developed for evaluating distributed PV resources. However, PGE also has an interest in evaluating utility scale resources. To accomplish this objective, the more challenging and detailed methods of distributed systems will be developed first. The methodology then will include descriptions of how to adapt this method for utility scale.

The main areas of difference lie in the development of fleet production profiles and loss savings calculations.

Methodology Framework

The methodology described here is designed primarily for determining the benefits and costs of the gross energy produced by a PV system prior to netting with local load. Variants of this methodology could be used to determine the value of energy exported to the grid after netting local load, but the methods for calculating export energy (i.e., what assumptions to make about customer load shape and PV size relative to usage) are not included in this methodology. These considerations should be taken into account when applying this methodology in valuing energy provided by NEM systems.

The value of distributed solar is the sum of several distinct value components, each calculated separately using separate procedures. As illustrated in Figure 1, the calculation of each component includes an initial value, a component-dependent load-match factor (as applicable to account for solar intermittency) and a component-dependent Loss Savings Factor.

For example, the avoided generation capacity cost includes an initial value that is calculated based on a perfectly-dispatchable, centralized resource. This is then corrected to account for the non-dispatchability of solar by multiplying it by the effective capacity load match factor. Next, loss savings are included using a factor that is calculated using a method that corresponds to the effective capacity calculation. From these two adjustments, a distributed PV value is calculated for avoided generation capacity cost. Similar adjustments are applied, as applicable, to the other cost and benefit components.

Distributed PV Values are summed as shown in Figure 1 to give the levelized value denominated in dollars per kWh.

Figure 1. Overview of value calculation

		Levelized Value	Gross Value A ($/kWh)	×	Load Match Factor B (%)	×	Loss Savings Factor (1+C) (%)	=	Distributed PV Value D ($/kWh)
Energy Supply		Avoided Fuel Cost	C1				LSF-Energy		V1
		Avoided Variable O&M Cost	C2				LSF-Energy		V2
		Avoided Fixed O&M Cost	C3		EC		LSF-EC		V3
		Avoided Gen. Capacity Cost	C4		EC		LSF-EC		V4
		(Solar Integration Cost)	(C5)				LSF-Energy		(V5)
Transmission and Distribution		Avoided Trans. Capacity Cost	C6		EC		LSF-EC		V6
		Avoided Dist. Capacity Cost	C7		PLR		LSF-Dist		V7
		Voltage Regulation	C8						V8
Environmental		Avoided Environmental Compliance	C9				LSF-Energy		V9
		Avoided SO_2 Emissions	C10				LSF-Energy		V10
Customer		Avoided Fuel Price Uncertainty	C11				LSF-Energy		V11
									Total

Applicability to Non-solar Technologies

Many of the techniques included in this methodology have historically been developed for evaluating solar resources; however PGE also has an interest in using these for non-solar technologies, such as CHP, microturbines, fuel cells, and energy storage. With this in mind, the methodology is intended to be technology neutral and applicable to all distributed generation technologies.

Each technology has a different production profile. While the solar profile ramps up and down over the course of the day, the microturbine is a dispatchable resource and its profile is therefore user-defined. For example, a customer-owned microturbine may be operated to maximize bill savings based on the customer's load profile and the rate schedule.

Regardless of technology, the technical and economic methods described here may be used. For example, if a dispatchable distributed microturbine is used, the effective capacity would be calculated using the same load match factors for distributed solar (see "Load Match Factors"). The result would be expected to be considerably higher for the microturbine than for solar, but the method is the same.

For example, Figure 1 shows that the Avoided Distribution Capacity Costs includes the gross value "C7." The value of C7 would be the same regardless of technology, calculated as described in the Avoided Distribution Capacity Cost section. However, the calculation of the load match factor "PLR" would be different for a microturbine versus a distributed solar resource. Both calculations would be based on the same method—see the method described in the Peak Load Reduction section—but the numerical result would be different. The resulting Loss Savings Factors "LSF-Dist" would also be slightly different for microturbines versus solar resources but would each be calculated using the same equation (4).

As an example, suppose that gross value C7 was $0.01 per kWh, PLR was determined to be 100% and 10% for the microturbine and solar, respectively, and LSF-Dist was 10% and 9% for the microturbine and solar, respectively. The resulting distributed PV values would be $0.01 x 1 x 1.10 = $0.011 per kWh and $0.01 x 0.1 x 1.09 = $0.00109 per kW, respectively.

Utility Avoided Costs

Figure 1 identifies costs and benefits of distributed solar that accrue to the utility and its customers. However, there may be other important societal benefits that are not included in this list. These are described more fully in the Societal Benefits section.

Methodology Objectives

The value of generated energy for each distributed PV system will differ because each system is a unique combination of many factors, such as:

- Irradiance patterns and shading at PV system geographical coordinates
- PV system orientation, such as the azimuth and tilt angle that define the daily generation profile
- Interconnection point of PV system on the transmission and distribution system
- Conductor sizing on local feeder

To calculate the value for each system would be highly impractical. Instead, it is useful to calculate average values for a defined group, such as for all distributed PV in the PGE service territory.

There is a natural tension between transparency and complexity of analysis. The intent of this methodology is to balance these two competing objectives as best as possible. For example, to evaluate avoided utility losses, every PV system could be modeled on the distribution system based on electrical location, wire size, regulator settings, and other modeling details. While this would provide the most satisfying engineering estimates, it is not practical from the standpoint of transparency because other stakeholders do not have access to the physical circuit models or the detailed device data that accompanies them. Implementing such a methodology would also be prohibitively costly. Therefore, a simplifying assumption employed here is to model the distribution system as a single component with single loss-versus-load curve rather than modeling each circuit separately.

Note that the methodology described here could be applied at varying levels of granularity. For example, the method could be applied at the level of the distribution circuit. This would require additional detail in input data (e.g., obtaining loss factors, hourly loads, and solar production profiles unique to each circuit). Such an analysis would result in the costs and benefits of distributed PV at the circuit level. It would be up to PGE to decide what level of granularity would be appropriate.

Marginal Fuel

This methodology calculates energy value as the avoided cost of fuel and O&M, assuming that PV displaces natural gas during PV operating hours. During some hours of the year, other fuels may be the fuel on the margin. In these cases, natural gas displacement is a simplifying assumption.

Lumpiness of Capital Investments

Capacity-related investments by PGE, whether for generation, transmission, or distribution, are planned such that the required capacity is installed and put into service in time to meet anticipated loads. This methodology implicitly assumes that DG is also installed and put into service in time to meet the same loads. It is not necessary that all DG is installed in a single year, but the cumulative capacity has to be sufficient to avoid the investment.

PGE Economic Analysis Period and Residual Value

PGE has set the analysis period for the Solar Generation Market Research work at 20 years. This period will largely overlap with the useful service life of PV, but not necessarily entirely. If the useful service life of PV is, for example, 25 years, then the selection of 20 years would capture only the first 20 years of value. PGE suggests incorporating “residual” value to account for the difference between service life and study period.

To accomplish this objective in the methodology, the following procedure is used. First, PGE will make an assumption about the PV service life. If the decision is made to adopt 20 years, then there is no residual value. If it is less than 20 years, then the analysis period should be set to the service life because no additional costs or benefits will be realized in the years that follow the service life. Finally, if PGE adopts a life assumption greater than 20 years (e.g. 25 years), then the methodology should be run twice: once with the service life and once with the study period. The difference in results should be added as another benefit category entitled “Residual Value.” Since the assumption is not known at this time, Residual Value is not shown explicitly in the summary chart in Figure 1.

PGE Assumptions and Sensitivities

This methodology does not propose specific input assumptions to perform the VOS calculations. These assumptions would largely be developed by PGE or other sources as a preliminary to conducting the VOS study. Therefore, the methodology is intended to treat assumptions as variables, although in some cases example values are used to illustrate calculation methods.

A VOS study may include, if desired, sensitivities to the input assumptions. For example, the PV degradation rate may be selected for the baseline assumption as 0.5 percent per year, but sensitivity runs may be performed using other values. The sensitivity runs would use the same methodology, but just incorporate different assumptions.

Methodology: Technical Analysis

Load Analysis Period

The VOS methodology requires that a number of technical parameters (PV energy production, effective capacity (EC) and peak load reduction (PLR) load-match factors, and electricity-loss factors) be calculated over a fixed period of time in order to account for day-to-day variations and seasonal effects, such as changes in solar radiation.

To ensure that the solar modeling is time-correlated with load, a historical "Load Analysis Period" must be selected over which the technical parameters are calculated. To account for seasonal variations, a minimum of one year is required. The Load Analysis Period may be lengthened (e.g., 3 years) if desired, to account for annual differences.

PV Energy Production

PV System Rating Convention

The methodology uses a rating convention for PV capacity based on AC delivered energy, taking into account losses internal to the PV system. This is in contrast to DC rating conventions based on Standard Test Conditions (STC). All PV capacity under this study is calculated by multiplying the DC rating by an STC-to-PTC derate factor,[1] by an inverter loss factor, and by an "other losses" factor. Typical assumptions might be 90%, 95%, and 85%, respectively, so the overall DC to AC derate factor using these assumptions would be 0.90 x 0.95 x 0.85 = 0.73, or 73% of the DC rating at standard test conditions.

The rating convention described above is one of several possible conventions used in the industry. The DC-STC rating convention is common (the DC-STC module rating times the number of modules), and it is easy to apply because the ratings are readily available from the module manufacturer. Another common convention is an "AC" rating calculated as the DC-STC rating times the STC-to-PTC derate factor times the load-weighted inverter efficiency. This is also relatively easy to implement because these factors are available from the module and inverter manufacturer. However, such a rating does not include system-level losses, such as the voltage-current mismatch between modules and strings. Such losses are specific to the system design and are therefore more difficult to obtain for each system individually. The above approach therefore makes an assumption of these other losses based on typical system performance.

[1] PTC refers to PVUSA Test Conditions, which were developed to test and compare PV systems as part of the PVUSA (Photovoltaics for Utility Scale Applications) project. PTC rating allows modules to come to steady state temperatures with external conditions of 1,000 Watts per square meter solar irradiance, 20 degrees C air temperature, and wind speed of 1 meter per second at 10 meters above ground level.

The rating convention is somewhat arbitrary; however PGE should be internally consistent when describing PV capacity. For example, when calculating the EC percentage, the result will differ if using AC or DC rating conventions. Similarly, when discussing future MW penetration levels, the rating convention should be clearly stated.

PGE PV Fleet Production Profiles

PV Fleet Production Profiles on an hourly basis over the Load Analysis Period will be developed using the method that follows. Note that the VOS is to be developed for future, as yet unbuilt resources, and that existing resources are used as a proxy for these systems. The existing systems serve as the best available data because they are found in locations (such as population centers) in proportion to where future capacity is likely to be built and they reflect the design attributes (roof pitches, etc.) that are representative of future systems.

PV resources at PGE include both behind-the-meter PV systems (distribution connected) as well as utility scale resources (transmission connected). As the VOS calculations will be done separately for these two types of resources, it is necessary to break these effectively into two fleets.

For the utility-scale resources, PGE may take the metered production over the Load Analysis Period, sum them hour for hour, and divide by the combined rating of the systems. This generation profile will reflect the irradiance values at the plant locations, and the specific design attributes for those plants.

The behind-the-meter resources are more complex. Generally, metered output for these resources is not available because production is netted with customer load on the customer side of the meter. Therefore, these resources are modeled using the time-synchronized solar resource data.

The PGE fleet comprises a large set of PV systems of 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. The principle is illustrated in Figure 2 where a range of tilt angles and azimuth angles would be expected to be found for the fleet. Each of these orientations contributes a different production profile as illustrated in Figure 3.

Figure 2. Illustration of capacity weighting by azimuth (x axis) and tilt angle (legend).

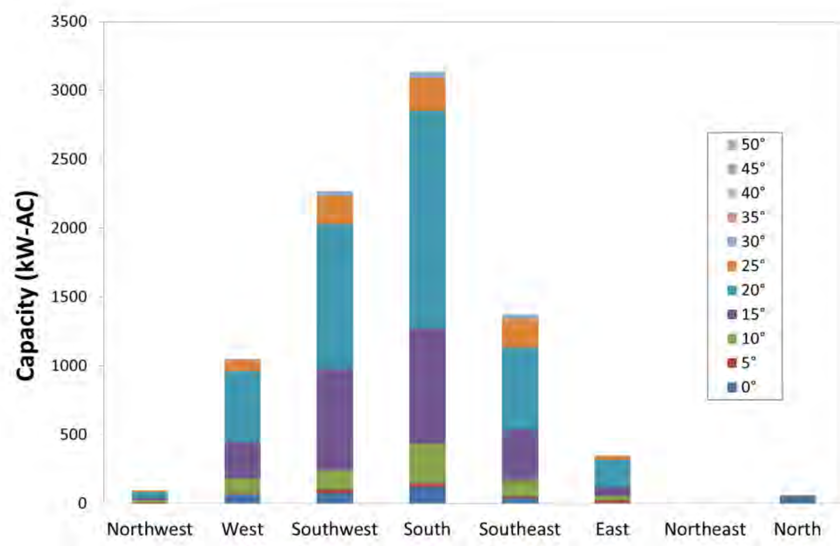
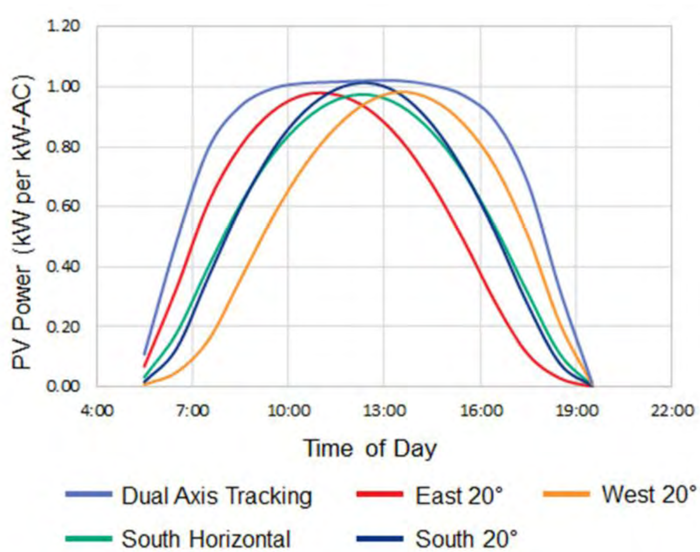


Figure 3. Illustration of PV generation profile by design orientation.



To develop the actual PV Fleet Production Profile it is necessary to take into account the actual fleet characteristics. This is done using the attributes collected in the PowerClerk® database for the Oregon Energy Trust (see Figure 4). Simulations may be performed using FleetView® software, incorporating satellite-derived irradiance data (SolarAnywhere®) or other simulation software, provided that the simulations are performed using actual design attributes for each system, and using irradiance and temperature data corresponding to each of the system locations.

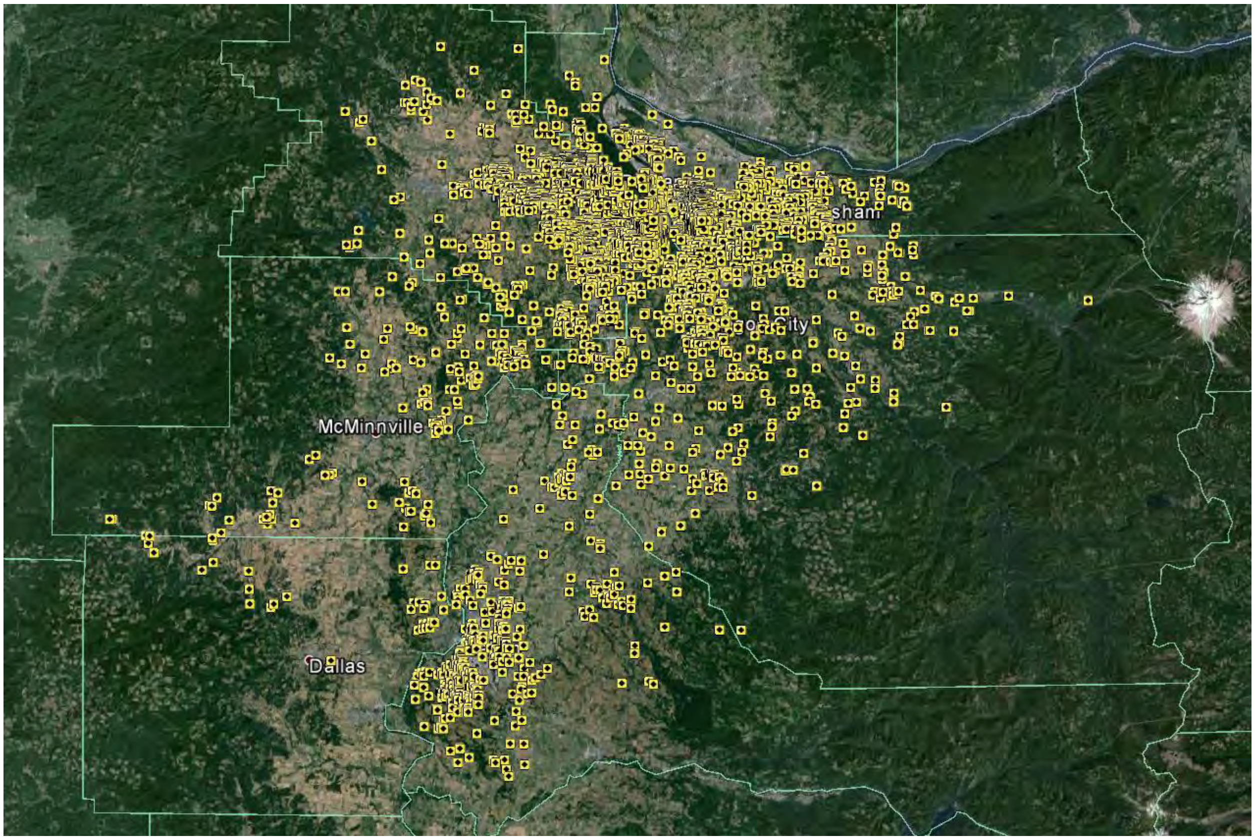


Figure 4. PGE behind-the-meter fleet locations (from FleetView).

For example, each system is mapped to its corresponding 10 km x 10 km weather data grid location from which temperature, wind speed, direct normal irradiance, and global horizontal irradiance would be taken. For each hour, the weather data is used, array-sun angles and plane-of-array irradiance is calculated, and PV system output is modeled with temperature and wind speed corrections.

PVFleetProduction

All systems are simulated individually over the Load Analysis Period, and the results aggregated. Finally, the energy for each hour is divided by the fleet aggregate AC rating. This results in the time series *PVFleetProduction* with units of kWh per hour per kW-AC (or, equivalently, average kW per kW-AC).

Marginal PV Resource

The PV Fleet Production Profile may be thought of as the hourly production of a Marginal PV Resource having a rating of 1 kW-AC. This “resource” does not exist in practice since there is no PV system having the output shape of the blended fleet. For ease of description, however, the term Marginal PV Resource is used and intended to mean the fleet blend as described above.

First Year Avoided Energy

The first year energy produced by PV (kWh per kW-AC per year), before annual PV degradation is taken into account, is the sum of the *PVFleetProduction* time series across all hours of the Load Analysis Period, divided by the number of years in the Load Analysis Period. The result is the first year annual output of the Marginal PV Resource.

$$AnnualEnergy_0 = \frac{\sum PVFleetProduction_h}{Number\ of\ Years} \tag{1}$$

$AvoidedEnergy_0$ does not include the effects of loss savings. The Loss Savings Analysis section describes the method for calculating factors to incorporate the effects of loss savings, and these factors are then used in the Final VOS Calculation section.

Load-Match Factors

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

- Effective Capacity (EC)
- Peak Load Reduction (PLR)

Effective Capacity

Effective Capacity (EC) is the measure of the capacity for distributed PV that is applied to avoided generation capacity costs, avoided fixed O&M costs, avoided reserve capacity costs, and avoided transmission capacity costs. It is expressed as a percentage of rated capacity, and the percentage is an indication of effectiveness relative to a fully dispatchable resource.

PGE may utilize any of several methods for calculating EC, many of which are detailed in NREL's overview of methods for evaluating DG costs and benefits.[2] Three methods are considered here:

- Production during defined peak periods
- Production during peak load hours
- Loss of load probability (LOLP)

The first method is to calculate the average hourly PV production during defined peak periods. This method was included in the Minnesota Value of Solar methodology in order to be compatible with MISO rules for non-wind variable generation.[3] In the MISO case, for example, the period was defined as the hours ending 14:00, 15:00, and 16:00 CST during June, July, and August over the last three years. This method is simple to calculate once the production time series dataset is prepared, it is easy for

[2] Denholm, et al., "Methods for Analyzing the Benefits and Costs of Distributed Photovoltaic Generation to the U.S. Electric Utility System," NREL, September 2014, available at: http://www.nrel.gov/docs/fy14osti/62447.pdf

[3] MISO BPM-011, Section 4.2.2.4, page 35, https://www.misoenergy.org/Library/BusinessPracticesManuals/Pages/BusinessPracticesManuals.aspx

stakeholders to understand, and it provides a straightforward methodology for implementation year after year in a tariff.

Alternatively, PGE could calculate EC based on distributed PV production during peak load hours. For example, the average production during the top 100 hours over the load analysis period could be used. This is also a simple calculation, and it provides a means for penetration level to be easily accounted for in future year updates. If penetration level increased, then peak hours may shift to non-solar hours, and this method would then result in an EC reflecting such a shift.

A third method would be to determine the rating of a dispatchable resource having the same loss of load probability (LOLP) as the Marginal PV Resource. This method provides a good measure of equivalent reliability, but it is more difficult to communicate to stakeholders and more difficult for stakeholders to validate independently.

While the PV capacity under evaluation is “new,” (i.e., installed in 2015), its impact on avoiding new generation capacity is not realized until at some year in the future (e.g., 2020), the year that new generation is scheduled for installation. Therefore, the EC of the new resource would be calculated for the year that new generation is scheduled for installation. For example, if the generation is scheduled for 2020, then the EC of the 2015 capacity would be evaluated based on the anticipated load shape in 2020.

Note that in order to ensure that PV production is correctly time-synchronized with load, both the PV production and the load data must be taken from the same hours. In this methodology, the time-synchronization is accomplished by using both PV fleet simulation results and load from the same hours in the Load Analysis Period. Utility loads are scaled according to projected retail sales (or projected peak load growth), taking into account anticipated PV capacity in the intervening years. It would not be correct to use “typical” year data for either the PV or load profiles unless the underlying raw data (temperature and irradiance) are taken from the same hours, i.e., the definition for typical year is the same for both load and PV.

For future years, the method for calculating utility hourly loads is as follows. First, utility loads from the Load Analysis Period are scaled by the projected annual energy sales (or projected peak load). All hourly loads are assumed to scale by this same ratio. Next, the hourly output of the differential PV resource for the future year (the difference between utility projected 2020 rooftop PV capacity and the PV capacity at the conclusion of the load analysis period) is calculated by multiplying the differential capacity by the hourly normalized fleet output.[4] Finally, the differential PV production is subtracted from the load to give the hourly net load.

This projection is illustrated in Figure 5 in which a 2020 generation capacity increase is assumed. The net load for 2020 is used to calculate EC.

[4] Normalized output is the output in MWh per MW-AC of fleet capacity.

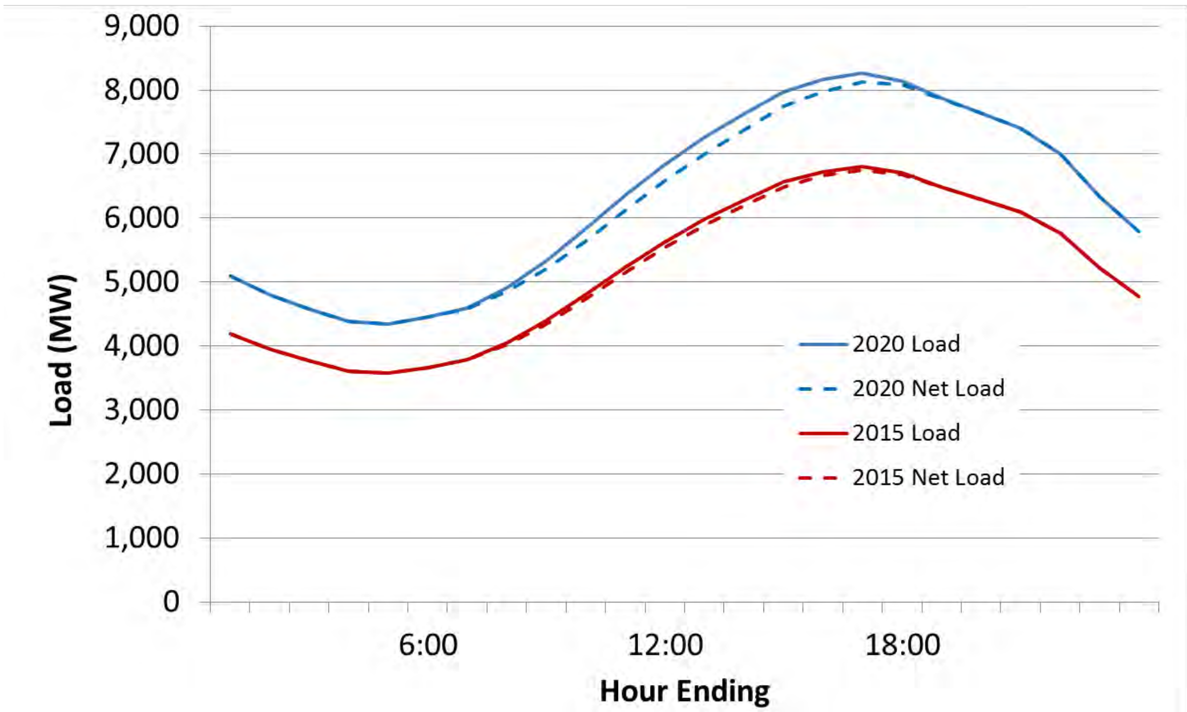


Figure 5. Peak day load and net load for 2015 and 2020 (illustrative).

As suggested by the chart, the EC may be a function of both the change in load and the change in PV installed capacity. Therefore, both of these effects need to be included in the calculation of future year EC.

The EC is calculated using PGE's selected method, then dividing by the rating of the Marginal PV Resource (1 kW-AC), which results in a percentage value. Annual ECs are then averaged over the Load Analysis Period (if more than one year) to give the final fleet EC.

Additionally, the EC must be calculated for the two loss cases (with and without T&D losses, as described in the Loss Savings Analysis subsection). Note that the inclusion of transmission losses is only true when the avoided generation is off-system, and this is not always the case.

Peak Load Reduction

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

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

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

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

Loss Savings Analysis

In order to calculate the required Loss Savings Factors on a marginal basis as described below, it is necessary to calculate EC, PLR and Annual Avoided Energy each twice. They should be calculated first by *including* losses, and second by *excluding* losses. For example, the EC would first be calculated by including transmission and distribution losses, and then re-calculated assuming no losses, i.e., as if the Marginal PV Resource was a central (not distributed) resource. The loss savings factor associated with EC (described below) is then calculated using the two results.

The calculations should observe the following

Table 1. Losses to be considered.

Technical Parameter	Loss Savings Considered
Annual Avoided Energy	Avoided transmission and distribution losses for every hour of the Load Analysis Period.
EC	Avoided transmission and distribution losses during the critical hours.
PLR	Avoided distribution losses (not transmission) at the peak hour.

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

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

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

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

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

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

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

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

Loss Savings Factors

The Energy Loss Savings Factor (as a percentage) is defined as follows:

$$Annual\ Avoided\ Energy_{WithLosses} = Annual\ Avoided\ Energy_{WithoutLosses}\left(1 + Loss\ Savings_{Energy}\right) \quad (2)$$

Equation (2) is then rearranged to solve for the Energy Loss Savings Factor:

$$Loss\ Savings_{Energy} = \frac{Annual\ Avoided\ Energy_{WithLosses}}{Annual\ Avoided\ Energy_{WithoutLosses}} - 1 \quad (3)$$

Similarly, the PLR Loss Savings Factor is defined as:

$$Loss\ Savings_{PLR} = \frac{PLR_{WithLosses}}{PLR_{WithoutLosses}} - 1 \quad (4)$$

And the EC Loss Savings Factor is defined as:

$$Loss\ Savings_{EC} = \frac{EC_{WithLosses}}{EC_{WithoutLosses}} - 1 \tag{5}$$

Methodology: Economic Analysis

The following subsections provide a methodology for performing the economic calculations to derive gross values in $/kWh for each of the VOS components.

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

Discount Factors

For this analysis, year 0 corresponds to the year of installation of the PV systems in question. As an example, if the calculation is performed for PV installations between January 1, 2016 and December 31, 2016, then year 0 would be 2016, year 1 would be 2017, and so on.

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

$$DiscountFactor_i = \frac{1}{(1 + DiscountRate)^i} \qquad (6)$$

DiscountRate is the PGE after tax Weighted Average Cost of Capital. Either real or nominal discount rates, depending on whether the levelized value is to be calculated on a real basis or a nominal basis.

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

$$RiskFreeDiscountFactor_i = \frac{1}{(1 + RiskFreeDiscountRate)^i} \qquad (7)$$

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

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

$$AnnualEnergy_i = AnnualEnergy_0 \times (1 - PVDegradationRate)^i \qquad (8)$$

where PVDegradationRate is the annual rate of PV degradation.[6] $AnnualEnergy_0$ is the First Year Avoided Energy for the Marginal PV Resource.

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

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

$$PVCapacity_i = PVCapacity_0 \times (1 - PVDegradationRate)^i \tag{9}$$

where $PVCapacity_0$ is the initial capacity of the marginal resource, i.e., 1 kW-AC.

Each benefit and cost category is levelized by discounting future year amounts to get NPV and then using the following relationship:

$$LevelizedValue = \frac{NPV}{\sum PVProduction_i \times DiscountFactor_i} \tag{10}$$

Avoided Fuel Cost

The solar-weighted heat rate is calculated for each month *m* as follows:

$$SolarWeighedHeatRate_m = \frac{\sum HeatRate_j \times PVFleetProduction_j}{\sum PVFleetProduction_j} \tag{11}$$

where the summation is over all hours *j* of the Load Analysis Period for the month, *HeatRate* is the actual heat rate of the plant on the margin, and *PVFleetProduction* is the time series calculated as described in the PV Energy Production section.

A burnertip fuel price by month is a required input for the Avoided Fuel Cost calculation. This input may be from an internal utility forecast or from public sources,[7] adjusted for delivery.

The avoided unit fuel cost (in $ per kWh) for year *i* is calculated as:

$$AvoidedUnitFuelCost_i = \sum_{m=0}^{11} \frac{BurnertipFuelPrice_{m,i} \times SolarWeighedHeatRate_m}{10^6} \tag{12}$$

where the burnertip price is in $ per MMBtu and the heat rate is in Btu per kWh. For each year, the Avoided Fuel Cost in $ per year is calculated by multiplying the above annual result ($ per kWh) by the fleet production in kWh for that year, taking into account solar degradation. This value stream is then discounted and levelized as described in equation (10).

[6] A good source of data for this assumption is the median value of systems from an NREL study of the literature. See Jordan and Kurtz, "Photovoltaic Degradation Rates – An Analytic Review," NREL, available at http://www.nrel.gov/docs/fy12osti/51664.pdf.

[7] For public sources, an option used in other studies is a combination of NYMEX NG futures (first 12 years) and then escalated using the EIA forecast of natural gas prices.

Avoided Variable O&M Cost

A required input to this calculation is the assumed first-year variable O&M cost in $ per kWh. This assumption should correspond to a typical resource that is displaced, such as a CCGT. For each year, escalate this value using an assumed escalation rate, multiply by the PV production in that year (after degradation), discount each year's value and levelize.

For example, if the variable O&M cost is $0.01 per kWh, nominal escalation is 2%, the first year Annual Energy is 1800 kWh per kW, and PV degradation is 0.05% per year, then the avoided O&M cost for study year 10 would be $0.01 x (1.02)^10 x 1800 x (0.95)^10 = $13 per kW-yr.

Avoided Generation Capacity Cost

Avoided Generation Capacity Cost is calculated initially for a "perfect" resource and is later adjusted based on the EC to account for the intermittent nature of the solar resource.

Generation capacity using conventional resources is assumed to take place at some year in the future. Therefore, new PV capacity (i.e., capacity added in 2015) will provide capacity immediately, but will not avoid capacity costs until the year in which new capacity was scheduled for construction. The methodology described here takes into account this time delay.

The key inputs for the Avoided Generation Capacity Cost component are the capital cost of new generating capacity (e.g., the installed cost of a CCGT) and the year in which the installation is expected to occur.

First, the capital cost is escalated to the assumed year of installation. In the example of Table 2 the escalated cost is shown as $1200 per kW occurring in 2020. This cost is amortized over the life of the plant (e.g., 30 years), and the example is an amortized cost of $106.59 beginning in study year 6. The potential avoided cost is represented, then, by the overlap of the annualized costs and the study period (PGE has defined this as 20 years). So, in this example, the amortized costs for years 6 through 19 are potentially deferrable. These costs are discounted to $598.08 per kW and levelized over the assumed 20 year life as $0.032 per kWh. In year 2030, for example, the levelized cost of $0.032 per kW may be multiplied by the PV production in that year of 1670 kWh per kW (after degradation) to obtain an avoided cost of $54.18 per kW. As a check in the calculation, the NPV for all years is shown to agree with the $598.08 per kW of avoided costs.

The capacity value should be adjusted to account for the fact that the displaced, dispatchable capacity could have been used during certain hours to dispatch economically in the market when not needed for load. Both energy and capacity could be sold during these hours.

Table 2. Avoided capacity value calculation (illustration only).

	Year	Disc. Fact.	Capital Cost ($/kW)	Amortized Cost ($/kW-yr)	Disc. ($/kW-yr)	Solar Production (kWh/kW)	Lev. Value ($/kWh)	Value ($/kW)	Disc. ($/kW)
0	2015	1.000				1,800	0.032	$ 58.41	$ 58.41
1	2016	0.926				1,791	0.032	$ 58.11	$ 53.81
2	2017	0.857				1,782	0.032	$ 57.82	$ 49.58
3	2018	0.794				1,773	0.032	$ 57.54	$ 45.67
4	2019	0.735				1,764	0.032	$ 57.25	$ 42.08
5	2020	0.681	1,200			1,755	0.032	$ 56.96	$ 38.77
6	2021	0.630		$106.59	$ 67.17	1,747	0.032	$ 56.68	$ 35.72
7	2022	0.583		$106.59	$ 62.20	1,738	0.032	$ 56.39	$ 32.90
8	2023	0.540		$106.59	$ 57.59	1,729	0.032	$ 56.11	$ 30.32
9	2024	0.500		$106.59	$ 53.32	1,721	0.032	$ 55.83	$ 27.93
10	2025	0.463		$106.59	$ 49.37	1,712	0.032	$ 55.55	$ 25.73
11	2026	0.429		$106.59	$ 45.72	1,703	0.032	$ 55.27	$ 23.71
12	2027	0.397		$106.59	$ 42.33	1,695	0.032	$ 55.00	$ 21.84
13	2028	0.368		$106.59	$ 39.19	1,686	0.032	$ 54.72	$ 20.12
14	2029	0.340		$106.59	$ 36.29	1,678	0.032	$ 54.45	$ 18.54
15	2030	0.315		$106.59	$ 33.60	1,670	0.032	$ 54.18	$ 17.08
16	2031	0.292		$106.59	$ 31.11	1,661	0.032	$ 53.91	$ 15.73
17	2032	0.270		$106.59	$ 28.81	1,653	0.032	$ 53.64	$ 14.50
18	2033	0.250		$106.59	$ 26.67	1,645	0.032	$ 53.37	$ 13.36
19	2034	0.232		$106.59	$ 24.70	1,636	0.032	$ 53.10	$ 12.30
	NPV				$ 598.08				$ 598.08

Avoided Reserve Capacity Cost

Distributed PV energy is delivered to the distribution system, not transmission. Therefore, load is reduced and the reserve requirement likewise decreases, similar to the effect of energy efficiency. Since this is just a fixed fraction of the generation capacity (e.g., 15%), it is treated as an add-on to the Avoided Generation Capacity Cost and included in that component.

Avoided Fixed O&M Cost

Again, the avoided costs are first calculated for a “perfect” resource and are later adjusted using the EC load match factor to account for the intermittent nature of PV.

The first year fixed O&M value ($ per kW) is an input to this calculation.

For each year, calculate the following:

- [1] the escalated cost of fixed O&M ($ per kW)
- [2] an index for the decreased capacity of the displaced generation resource taking into account the degradation of plant output over time. For simplicity, the heat rate degradation (from the fuel cost calculation) may be used.
- [3] an index for the decreased capacity of PV, taking into account the PV degradation rate.

- [4] the adjusted O&M cost ($ per kW) for that year, calculated as [1]x[3]/[4]

The NPV of this time series is calculated and levelized over the study period.

Solar Integration Cost

The Solar Integration Cost is the cost of the operational modifications needed to accept variable distributed PV onto the system. This variability is a function of PV penetration (MW of PV resource relative to the overall load), the geographical spread of resource, the time period of interest (i.e., the four second AGC period), and the speed of clouds causing the transients.

For example, two PV systems (System A and System B) located adjacent to each other would be highly time-correlated because a given cloud transient, measurable within the AGC period would be observable in the change in output for both System A and System B. However, if the two resources were separated by a large distance, the two would not be time correlated. In this case, a cloud transient may be observable at A (say, a sudden increase in PV power), but four seconds would not be sufficient time for the cloud to traverse the distance. At B, it is possible that (1) there is no cloud transient; (2) that there is a transient in the opposite direction (a sudden decrease in PV power); and (3) that there is a transient in the same direction.

With a large number of systems sufficiently spread out, the aggregate change in required regulation is a probabilistic function of the behavior of many systems. To measure the aggregate change, it would be necessary to meter distributed PV resources of the fleet, sample the integrated energy for each system over the four second period, and aggregate the time-synchronized results. The data would have to be collected over a representative duration, such as the Load Analysis Period (or at least a representative year). The cost and complexity of such as study by PGE would be considerable, however, and impractical for purposes of this methodology.

Two studies are available that may be of interest to PGE in estimating the integration costs. The first was conducted by Idaho Power,[8] which estimated costs of real-time market activities associated with deviations in solar production forecasts under hour-ahead scheduling. Load following resources were a mix of hydroelectric resources, gas-fired generators, and coal-fired generators. Costs ranged from $0.40 per MWh to $2.50 per MWh for PV capacity ranging from 100 MW to 700 MW. However, this study utilized data from only six locations using five minute intervals. The distributed fleet at PGE would comprise roughly 1500 times the number of locations[9] and 75 times the temporal resolution, both of which result in very little output correlation. On the other hand, many of these systems would be clustered in some areas with possible time correlation.

[8] Solar Integration Study Report, 2014, by Idaho Power, available at https://www.idahopower.com/AboutUs/PlanningForFuture/SolarStudy/default.cfm.
[9] Roughly 9000 distributed systems in PGE's existing fleet divided by 6 systems in the Idaho sample is 1500.

A second relevant study was performed by Duke Energy Carolinas,[10] resulting in a range of $2 to $7 per MWh for baseline scenarios, for the penetration years 2014 to 2022. In this case, one-minute time-synchronized data was used for PV located in about 300 locations (at zip code centroids). It is also difficult to determine how these results may compare with PGE, except to recognize that capacity would be spread throughout each zip code rather than concentrated at a single location.

A study similar to the Duke Energy study could be performed at PGE using PV simulations using the exact locations of the distributed fleet over the Load Analysis Period. This would eliminate the geographical uncertainty, but it would be limited to the best available satellite-derived data time resolution of one-minute. There are other, advanced methods[11] that could be adapted to quantifying fleet variability at the four-second AGC time interval, but these have not been demonstrated yet for actual fleets.

For purposes of the methodology in the absence of PGE-specific results, PGE should either estimate a $ per MWh cost using best judgment from the available studies performed elsewhere, develop its own integration cost methodology, or assume that the cost is negligible.

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. This benefit assumes that the avoided resource is “off system,” although this may not always be the case.

Avoided Transmission Capacity Cost is calculated initially for a “perfect” resource and is later adjusted based on the EC to account for the intermittent nature of the solar resource.

The methodology for this value component is identical to that of Avoided Generation Capacity Cost, except that the cost of new transmission capacity is used ($ per kW) and the year that new generation capacity is expected. Table 2 is an example format for calculating this value.

Avoided Distribution Capacity Cost

As peak demand grows, distribution circuits and substations can approach capacity limits, requiring capital investments in distribution plant. Under these conditions, distributed PV may potentially defer or avoid the need to make these investments, provided that PV production is coincident with the local demand.

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[10] Lu, S., et. al., Duke Energy Photovoltaic Integration Study: Carolinas Service Areas, available at http://www.pnnl.gov/main/publications/external/technical_reports/PNNL-23226.pdf. Clean Power Research provided the underlying solar data to PNNL for this work.

[11] For example, see http://www.cleanpower.com/wp-content/uploads/2012/02/071_ModelingPVFleetOutputVariability.pdf .

The intent of this methodology is to capture the benefit, if any, in deferring capacity-related capital expenditures, to the extent that distributed resources are able to defer them. Distribution expenditures that are intended to provide reliability are not deferrable.

This section describes the method for calculating avoided costs for a “perfect” resource. The match between solar and distribution peak is incorporated in the PLR load match factor described previously. Note that PGE performs planning studies and develops projects to provide reliable service under a range of system conditions. This includes winter days with heavy cloud cover, when solar availability may be at a minimum. In the extreme case, the PLR would be zero, that is, the distributed resource would not support the peak load at all. In this case the Avoided Distribution Capacity Cost would be zero and it would not be necessary to calculate the economic value.

Under certain scenarios, it is possible that distributed generation would require additional capacity-related investments, so this category would potentially be a cost rather than a benefit. For example, if the amount of DG were installed locally in sufficient quantity as to require new line or transformer capacity, and if the cost of this new capacity were greater than the savings realized elsewhere on the system, then there would be a net overall cost to PGE.

PGE’s summer peak load typically occurs at 4:00 to 6:00 PM, where the winter peak load occurs at 8:00 to 11:00 AM and again at 6:00 to 8:00 PM. Depending on the relative magnitudes of the peaks in specific distribution areas, the best match may be provided by west-facing systems. Using this methodology, it would be possible to quantify relative value for such configuration options if desired. Using the PV Fleet Production methods described above, however, the benefits and costs are calculated for the broad range of designs, some of which are not optimized for distribution benefits.

Avoided distribution capacity costs are determined using capital investment and peak growth rate data from each of the last 10 years. The costs and growth rate must be taken over the same time period because the historical investments must be tied to the growth associated with those investments.

All costs for each year for FERC accounts 360, 361, 362, 365, 366, and 367 should be included. These costs, however, should be adjusted to consider only capacity-related amounts as illustrated in Table 3. Note that the capacity-related percentages are for illustration, and PGE may elect to modify these percentages.

The table illustrates the calculation of capacity-only investments for a sample year. Costs (e.g., new tie lines) that are for reliability should not be counted.

Table 3. (EXAMPLE) Determination of deferrable costs.

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

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

Note that this method results in capital cost per unit of load growth, not per unit of capacity. It would be incorrect to use the added distribution capacity that results from this investment.

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

$$GrowthRate = \left(\frac{P_{15}}{P_1}\right)^{1/14} - 1 \tag{13}$$

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

Example Calculation

An example calculation of avoided distribution capital cost is presented in Table 4. This method is intended to derive an approximate value of the potential value that results from deferring capacity-related investments, assuming that there is a perfect load match between the distributed generation resource and the load, i.e., if the resource provided a constant reduction in load for every hour of the year. The actual load match, if any, is accounted for in the PLR load match factor.

This example includes two separate sections: the "Conventional Distribution Planning" section and the "Deferred Distribution Planning" section.

In the "Conventional Distribution Planning" section, the distribution cost for the first year is assumed to be $200 per kW of load growth. While the details in obtaining this cost are not shown, it is taken as an example value as if it were calculated using the method described above. This cost is escalated each year using an assumed PGE escalation rate for distribution capital costs.

For each future year, the amount of new distribution capacity is calculated based on the growth rate, and this is multiplied by the cost per kW to get the cost for the year. Note that for the first year or two, it may be possible to estimate actual capital costs based on existing expansion plans. However, since this data is not available over the economic study period, an estimate must be made based on the cost per unit of load growth.

In the example, the first year distribution capacity additions are shown as 50 MW. This is calculated based on the growth rate and the existing peak load. Multiplying 50 MW by the cost gives $10M for the first year, and this is discounted. Each future year is calculated in a similar fashion by taking into account the escalation rate of distribution capital costs, the expected load growth for that year, and the discount factor for that year.

The total discounted cost is determined by summing the discounted expenditures (shown as $149M in the example). This cost is then amortized over the study period.

The total discounted cost of the deferred time series is calculated ($140M) and amortized.

Avoided costs are calculated using the difference between the amortized costs of the conventional plan and the amortized cost of the deferred plan. For example, the avoided cost for 2022 is ($14M - $13M)/54MW = $14 per effective kW of PV, and this is discounted to $8 per kW. Summing the discounted avoided costs for all years gives $166 per kW. The levelized VOS that gives the same NPV is shown to be $0.008 per kWh, taking into account the annual degradation of PV.

The method assumes implicitly that PV is assumed to be installed in sufficient capacity to allow the investment stream to be deferred for one year. In the example chart, distribution capacity supporting 50 MW of load growth would be deferred. Suppose that of these 50 MW, a 10 MW of load growth is expected in a particular area, but only 5 MW of cumulative DG is installed in that area. In this case, the distribution deferral would not be possible.

Table 4. (EXAMPLE) Economic value of avoided distribution capacity cost.

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

Table 4. (CONTINUED)

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

Validation: Present Value	$166	$166

Voltage Regulation

Distribution utilities have the responsibility to deliver electricity to customers within specified voltage windows. 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. To quantify these costs, PGE may consider all systems installed over a representative period, e.g., the last three years, add the utility distribution costs associated with interconnecting these systems, and divide by the total rated capacity of these systems. Some systems (e.g., small systems in areas with high loads) may have no added cost, while some systems (e.g., large systems in areas with low loads or limited circuit capability) would have high costs. The aggregate cost per kW-AC would then be levelized over the analysis period.

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 is kept as a placeholder for future value analyses.

Avoided Environmental Costs

With distributed PV, environmental emissions including carbon dioxide (CO_2), sulfur dioxide (SO_2), and nitrous oxides (NO_x) will be avoided, and these value components are defined to reflect these benefits. Other indirect environmental impacts (such as health care costs, etc.) are not included.

Estimates of avoided environmental costs are done in two steps: (1) determine the annual avoided emissions in tons of pollutant per MWh of PV production; and (2) applying forecasted market prices to the avoided emissions.

Calculating Avoided Emissions

Avoided emissions are calculated using the U.S. Environmental Protection Agency's "AVoided Emissions and geneRation Tool" (AVERT)[12] which calculates state-specific hourly avoided emissions of carbon dioxide (CO_2), nitrous oxides (NO_x), and sulfur dioxide (SO_2). The Northwest data file, or a PGE specific data file, would be used for the calculations.

Hourly avoided emissions are calculated using the PV Fleet Production Profile, and the average avoided emissions per year over the Load Analysis Period will be used as the annual avoided emissions per kWh.

Environmental Compliance

The State of Oregon has adopted a renewable portfolio standard (RPS)[13] which sets forth requirements for the delivery of electricity derived from renewable resources, expressed as a percentage of electricity sold to retail customers. As distributed PV is a qualifying renewable resource, the electricity produced may have value to PGE by reducing the quantity of renewable electricity to be procured. The value of the renewable attribute is captured in the value of renewable energy credits (RECs) associated with the distributed PV energy.

Another possible compliance benefit is related to possible greenhouse gas (GHG) compliance stemming from Section 111(d) of the Clean Air Act. If implemented, this will require Oregon to develop standards of performance for existing carbon sources and PGE would have to take measures to reduce carbon emissions. Distributed PV would partly reduce these compliance costs by reducing the amount of generation needed from carbon producing sources. The benefit per MWh may be calculated by PGE once the specifics of the compliance plan are developed.

If Section 111(d) is not implemented, then the valuation is simplified and the REC value may be taken as the compliance value. However, if Section 111(d) is implemented, then measures taken to meet the RPS requirement may also meet some, or all, of the GHG requirement. The cost of compliance will therefore be the cost to meet the RPS requirement, or the cost to meet the GHG requirement, whichever is greater.

The exact determination may need to change as regulatory rules are adopted.

Once these costs ($ per MWh) are known, then the calculation is performed for each year by multiplying the cost by PVProduction for that year. The result is a series of expenditures that may be discounted using each year's discount factor to obtain the NPV. Then, the NPV is levelized to give the levelized cost per kWh.

Avoided SO_2 Emissions

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[12] http://epa.gov/avert/
[13] Oregon Renewable Energy Act of 2007 (Senate Bill 838).

Avoided SO_2 Emissions will be calculated by applying the latest EPA allowance clearing price[14] to the AVERT analysis results, adjusting for inflation and PV degradation, and levelized using the standard discount rate.

Avoided Fuel Price Uncertainty

This value accounts for the avoidance of fuel price volatility associated with natural gas generation that is not present for solar generation. To put these two generation alternatives on the same footing, we calculate the cost that would be incurred to remove the price uncertainty for the amount of energy associated with solar generation.

The treatment of avoided uncertainty would be different depending upon metering arrangements. If solar generation is used to serve loads behind the meter, then this benefit accrues to the solar customer by avoiding energy purchased from the utility. If the energy is delivered to the grid directly for use by PGE in serving its customers, then the benefit accrues to all customers.

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.

To eliminate the fuel price uncertainty in year *i*, one could enter into a futures contract for natural gas delivery in year *i*, and invest sufficient funds today in risk-free securities that mature in year *i*. The steps required are therefore as follows:

- Obtain the natural gas futures price for year *i*.
- Calculate the amount of avoided fuel based on an assumed heat rate and on the amount of anticipated plant degradation in year *i*, and calculate this future cost.
- Obtain the risk-free interest rate corresponding to maturation in year *i*.
- Discount the expense to obtain the present value using the risk-free discount rate.
- Subtract from this result the energy value, which is obtained by discounting the future expense at the utility discount rate. Note that this may not be equal to the energy value obtained through the use of electricity market values.
- The remaining value is the avoided risk.
- Levelize the avoided risk value using the risk-free discount rate.
- Repeat for all remaining years in the study period and sum.

There are two practical difficulties with this method, requiring some simplifying assumptions. First, it is difficult to obtain futures prices for contracts as long as the assumed PV life. The most readily available public data is the NYMEX market prices, but these are available only for 12 years. As a simplification, the methodology assumes NYMEX prices for the first 12 years, and then escalated values as described in the Avoided Fuel Cost section.

[14] http://www.epa.gov/airmarkets/trading/2014/14summary.html

Second, while U.S. government securities provide a public source of effectively risk-free returns, these securities are only available for selected terms. For example, Treasury notes are available with maturities of 2, 3, 5, 7, and 10 years, but when it is necessary to have a yield corresponding to 6 years, there is no security available. To overcome this problem, linear interpolation is employed as required.

The above method may be adjusted to account for added market exposure related to solar variability. The addition of distributed solar will add uncertainty to forecasts of net load that are used to dispatch resources. In some cases, PGE will buy deficit power from the market, and in other cases PGE will sell excess power to the market. The effect of forecast bias error should be evaluated.

Final VOS Calculation

The values calculated above need to be adjusted for load match factors and loss savings factors. This is illustrated in Figure 1. The results are summed to give the distributed PV value.

Utility Scale Resources

For utility scale resources connected to transmission, the following modifications are required. First, these do not avoid transmission or distribution capital costs, so these components are removed. Second, these resources do not avoid losses in either the transmission or distribution system, so the loss savings factors are set to zero. These modifications are illustrated in Figure 6.

	Levelized Value	Gross Value A ($/kWh)	×	Load Match Factor B (%)	×	Loss Savings Factor (1+C) (%)	=	Distributed PV Value D ($/kWh)
Energy Supply	Avoided Fuel Cost	C1				~~LSF-Energy~~		V1
	Avoided Variable O&M Cost	C2				~~LSF-Energy~~		V2
	Avoided Fixed O&M Cost	C3		EC		~~LSF-EC~~		V3
	Avoided Gen. Capacity Cost	C4		EC		~~LSF-EC~~		V4
	(Solar Integration Cost)	(C5)				~~LSF-Energy~~		(V5)
Transmission and Distribution	~~Avoided Trans. Capacity Cost~~	~~C6~~		~~EC~~		~~LSF-EC~~		~~V6~~
	~~Avoided Dist. Capacity Cost~~	~~C7~~		~~PLR~~		~~LSF-Dist~~		~~V7~~
	~~Voltage Regulation~~	~~C8~~						~~V8~~
Environmental	Avoided Environmental Compliance	C9				~~LSF-Energy~~		V9
	Avoided SO_2 Emissions	C10				~~LSF-Energy~~		V10
Customer	Avoided Fuel Price Uncertainty	C11				~~LSF-Energy~~		V11
								Total

Figure 6. Final VOS calculation for utility scale resources.

Societal Benefits

The sections above are intended to provide methods to estimate the benefits and costs from the utility perspective, that is, only the benefits and costs which accrue to the utility and its customers. There are additional benefits that may accrue to society, and these are described in this section.

Clean Power Research does not recommend to PGE whether any of the societal benefits should be included or excluded from a benefit and cost study. They represent public policy choices that must be evaluated by the affected parties.

Social Cost of Carbon

The Avoided Social Cost of Carbon (SCC) is a measure of the externality benefit based on the federal social cost of avoided CO_2 emissions. This cost is included here for completeness as it has been used as the basis of other value of solar studies.

The value for each year is calculated as follows. The SCC values for each year through 2050 are published by the EPA in 2007 dollars per metric ton.[15] For example, the SCC for 2020 (3.0% discount rate, average) is \$43 per metric ton of CO_2 emissions in 2007 dollars. These costs are adjusted for inflation, converted to dollars per short ton, and converted to cost per kWh using the AVERT analysis results, adjusting for PV degradation.

These values are then levelized using the environmental discount rate that corresponds to the selected SCC scenario. For example, if the SCC values were taken using the 3% discount rate scenario, then the environmental discount rate would be 3%. As this is a *real* discount rate, it may be converted into an equivalent nominal discount rate as follows:

$$NominalDiscountRate = (1 + RealDiscountRate) \times (1 + GeneralEscalationRate) - 1 \tag{14}$$

The environmental discount factor is given by:

$$EnvironmentalDiscountFactor_i = \frac{1}{(1 + EnvironmentalDiscountRate)^i} \tag{15}$$

Other Potential Values

[15] 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.epa.gov/oms/climate/regulations/scc-tsd.pdf

Other potential values of solar have been identified through a number of studies, summarized by a 2013 RMI meta-study.[16] These include:

- Market Price Response
- Economic Development
- Reliability and Resilience
- Land
- Water

In general, utility avoided costs are much easier to estimate than societal benefits because they are tied to market prices. For example, avoided fuel costs are relatively straightforward to calculate based on marginal heat rates and gas prices, although there is uncertainty associated with gas price forecast. Similarly, capacity costs are also relatively straightforward because costs are readily available based on equipment costs and installation experience.

On the other hand, pricing sources are not typically available for societal benefits, so estimates are more difficult. The potential societal benefit of land, for example, represents the societal value of leaving land undisturbed, land that may otherwise be required for building generation or T&D capacity. It would not be appropriate to use available land prices in such a valuation for two reasons. First, the land price is already embedded in the generation and T&D capacity benefits (land costs, land right-of-ways, and so on). Second, and more importantly, it is extremely difficult to estimate the societal benefit that comes from leaving land undeveloped. These benefits may include such things as the value of preserving open space for public enjoyment and the value of undisturbed habitat for the preservation of wildlife. These things are extremely difficult to quantify and are therefore highly speculative.

A similar difficulty may be found in quantifying the value of water. While the avoided cost of cooling water is embedded in the O&M cost, the societal benefit is more complicated. It is extremely difficult to determine the social benefit of leaving waterways undisturbed. In the case of hydroelectric power, other difficulties would arise related to the costs and benefits of recreational use, the impact on fisheries and agricultural interests, the effect on Native American communities, and so on.

Among these five potential values, the first three have associated methodologies that have been used in prior solar valuation studies. While speculative, these may be used or adapted if PGE were to decide to include them. The last two (land and water) do not have established methodologies.

Market Price Response

[16] A Review of Solar PV Benefit and Cost Studies, Electricity Innovation Lab, Rocky Mountain Institute, 2013, available at http://www.rmi.org/cms/Download.aspx?id=10793&file=eLab_DERBenefitCostDeck_2nd_Edition&title=A+Review+of+Solar+PV+Benefit+and+Cost+Studies.pdf

This potential benefit refers to DG's effect on market prices related to a reduction in demand. Sometimes called "Demand Reduction Induced Price Effect (DRIPE)," price reductions may potentially be found in gas supply, electric energy, and electric capacity. While the price effects may be small, they would benefit all PGE customers for all energy sold, whether DG participants or not. The methodology is laid out in Chapter 7 of the *Avoided Energy Supply Costs in New England: 2013 Report.*[17]

Economic Development

Another component of value may derive from the increase in local solar jobs (e.g., engineering and installation), netted against losses of jobs for conventional power generation and delivery. Indirect benefits from these jobs may also result: increase in tax revenue that benefits state and local communities, and the multiplier effect (increase in local retail economic activity as a result of the net jobs increase), but these are more speculative.

A sample calculation of these benefits is found on p. 16-17 in a valuation study performed for Solar San Antonio.[18]

Reliability and Resilience

Another possible value relates to the ability of distributed solar to enhance the speed of recovery following major natural disasters, such as earthquakes, hurricanes, and tsunamis. These events generally result in widespread power outages. If DG is available to provide power to key customers, operating as individual islands, the recovery can be hastened and the total economic damage lessened. For example, DG at a grocery store or hardware store may be able to assist in recovery efforts, enabling the retailer to serve the community in the absence of utility power. Similarly, generation sources at hospitals, police stations, and fire stations may enable essential services.

It is important to note that such benefits cannot be provided unless the DG equipment is designed to operate without the utility present. For example, a solar generator may be equipped with an inverter that requires a utility voltage (current source mode) and not able to serve islanded loads independently. If so, then this benefit would not be provided by the generator.

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[17] Hornby, et al., *Avoided Energy Supply Costs in New England: 2013 Report*, Prepared for the Avoided-Energy-Supply-Component (AESC) Study Group, July 12, 2013, Synapse Energy Economics, available at http://www.synapse-energy.com/sites/default/files/SynapseReport.2013-07.AESC_.AESC-2013.13-029-Report.pdf

[18] Jones, N, and Norris, B, *The Value of Distributed Solar Electric Generation to San Antonio*, March 2013, available at: http://www.solarsanantonio.org/wp-content/uploads/2013/04/Value-of-Solar-at-San-Antonio-03-13-2013.pdf

A more complete description and methodology is provided in the "Disaster Recovery" section of the solar value report performed for Austin Energy in 2006.[19]

[19] Hoff, et al., The Value of Distributed Photovoltaics to Austin Energy and the City of Austin, Clean Power Research, March 2006, available at: http://www.ilsr.org/wp-content/uploads/2013/03/Value-of-PV-to-Austin-Energy.pdf.