Minnesota Value of Solar: Methodology

Prepared for

Minnesota Department of Commerce,

Division of Energy Resources

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Executive Summary

Minnesota passed legislation[1] in 2013 that allows Investor-Owned Utilities (IOUs) to apply to the Public Utility Commission (PUC) for a Value of Solar (VOS) tariff as an alternative to net metering, and as a rate identified for community solar gardens. The Department of Commerce (Commerce) was assigned the responsibility of developing and submitting a methodology for calculating the VOS tariff to the PUC by January 31, 2014. Utilities adopting the VOS will be required to follow this methodology when calculating the VOS tariff. Commerce selected Clean Power Research (CPR) to support the process of developing the methodology, and additionally held four public workshops to develop, present, and receive feedback.

The 2013 legislation specifically mandated that the VOS legislation take into account the following values of distributed PV: energy and its delivery; generation capacity; transmission capacity; transmission and distribution line losses; and environmental value. The legislation also mandated a method of implementation, whereby solar customers will be billed for their gross electricity consumption under their applicable tariff, and will receive a VOS credit for their gross solar electricity production.

The present document provides the methodology to be used by participating utilities. It is based on the enabling statute, stakeholder input, and guidance from Commerce. It includes a detailed example calculation for each step of the calculation.

Key aspects of the methodology include:

- A standard PV rating convention
- Methods for creating an hourly PV production time-series, representing the aggregate output of all PV systems in the service territory per unit capacity corresponding to the output of a PV resource on the margin
- Requirements for calculating the electricity losses of the transmission and distribution systems
- Methods for performing technical calculations for avoided energy, effective generation capacity and effective distribution capacity
- Economic methods for calculating each value component (e.g., avoided fuel cost, capacity cost, etc.)
- Requirements for summarizing input data and final calculations in order to facilitate PUC and stakeholder review

Application of the methodology results in the creation of two tables: the VOS Data Table (a table of utility-specific input assumptions) and the VOS Calculation Table (a table of utility-specific total value of

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[1] MN Laws 2013, Chapter 85 HF 729, Article 9, Section 10.

solar). Together these two tables ensure stakeholder transparency and facilitate stakeholder understanding.

The VOS Calculation Table is illustrated in Figure ES-1. The table shows each value component and how the gross value of each component is converted into a distributed solar value. The process uses a component-specific load match factor (where applicable) and a component-specific Loss Savings Factor. The values are then summed to yield the 25-year levelized value.

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

25 Year Levelized Value	Gross Value ($/kWh)	×	Load Match Factor (%)	× (1 +	Loss Savings Factor (%)	)	=	Distributed PV Value ($/kWh)
Avoided Fuel Cost	GV1				LSF-Energy			V1
Avoided Plant O&M - Fixed	GV2				LSF-Energy			V2
Avoided Plant O&M - Variable	GV3				LSF-Energy			V3
Avoided Gen Capacity Cost	GV4		ELCC		LSF-ELCC			V4
Avoided Reserve Capacity Cost	GV5		ELCC		LSF-ELCC			V5
Avoided Trans. Capacity Cost	GV6		ELCC		LSF-ELCC			V6
Avoided Dist. Capacity Cost	GV7		PLR		LSF-PLR			V7
Avoided Environmental Cost	GV8				LSF-Energy			V8
Avoided Voltage Control Cost								
Solar Integration Cost								
								Value of Solar

As a final step, the methodology calls for the conversion of the 25-year levelized value to an equivalent inflation-adjusted credit. The utility would then use the first year value as the credit for solar customers, and would adjust each year using the latest Consumer Price Index (CPI) data.

Contents

Introduction

Background

Minnesota passed legislation[2] in 2013 that allows Investor-Owned Utilities (IOUs) to apply to the Public Utility Commission (PUC) for a Value of Solar (VOS) tariff as an alternative to net metering, and as a rate identified for community solar gardens. The Department of Commerce (Commerce) was assigned the responsibility of developing and submitting a methodology for calculating the VOS tariff to the PUC by January 31, 2014. Utilities adopting the VOS will be required to follow this methodology when calculating the VOS rate. Commerce selected Clean Power Research (CPR) to support the process of developing the methodology, and additionally held four public workshops to develop, present, and receive feedback.

The present document provides the VOS methodology to be used by participating utilities. It is based on the enabling statute, stakeholder input and guidance from Commerce.

Purpose

The State of Minnesota has identified a VOS tariff as a potential replacement for the existing Net Energy Metering (NEM) policy that currently regulates the compensation of home and business owners for electricity production from PV systems. As such, the adopted VOS legislation is not an incentive for distributed PV, nor is it intended to eliminate or prevent current or future incentive programs.

While NEM effectively values PV-generated electricity at the customer retail rate, a VOS tariff seeks to quantify the value of distributed PV electricity. If the VOS is set correctly, it will account for the real value of the PV-generated electricity, and the utility and its ratepayers would be indifferent to whether the electricity is supplied from customer-owned PV or from comparable conventional means. Thus, a VOS tariff eliminates the NEM cross-subsidization concerns. Furthermore, a well-constructed VOS tariff could provide market signals for the adoption of technologies that significantly enhance the value of electricity from PV, such as advanced inverters that can assist the grid with voltage regulation.

VOS Calculation Table Overview

The VOS is the sum of several distinct value components, each calculated separately using procedures defined in this methodology. As illustrated in Figure 1, the calculation includes a gross component value, a component-dependent load-match factor (as applicable for capacity related values) and a component-dependent Loss Savings Factor.

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[2] MN Laws 2013, Chapter 85 HF 729, Article 9, Section 10.

For example, the avoided fuel cost does not have a load match factor because it is not dependent upon performance at the highest hours (fuel costs are avoided during all PV operating hours). Avoided fuel cost does have a Loss Savings Factor, however, accounting for loss savings in both transmission and distribution systems. On the other hand, the Avoided Distribution Capacity Cost has an important Load Match Factor (shown as Peak Load Reduction, or 'PLR') and a Loss Savings Factor that only accounts for distribution (not transmission) loss savings.

Gross Values, Distributed PV Values, and the summed VOS shown in Figure 1 are all 25-year levelized values denominated in dollars per kWh.

Figure 1. Illustration of the VOS Calculation Table

25 Year Levelized Value	Gross Value ($/kWh)	×	Load Match Factor (%)	× (1 +	Loss Savings Factor (%)	) =	Distributed PV Value ($/kWh)
Avoided Fuel Cost	GV1				LSF-Energy		V1
Avoided Plant O&M - Fixed	GV2				LSF-Energy		V2
Avoided Plant O&M - Variable	GV3				LSF-Energy		V3
Avoided Gen Capacity Cost	GV4		ELCC		LSF-ELCC		V4
Avoided Reserve Capacity Cost	GV5		ELCC		LSF-ELCC		V5
Avoided Trans. Capacity Cost	GV6		ELCC		LSF-ELCC		V6
Avoided Dist. Capacity Cost	GV7		PLR		LSF-PLR		V7
Avoided Environmental Cost	GV8				LSF-Energy		V8
Avoided Voltage Control Cost							
Solar Integration Cost							
							Value of Solar

VOS Rate Implementation

Separation of Usage and Production

Minnesota's VOS legislation mandates that, if a VOS tariff is approved, solar customers will be billed for all usage under their existing applicable tariff, and will receive a VOS credit for their gross solar energy production. Separating usage (charges) from production (credits) simplifies the rate process for several reasons:

- Customers will be billed for all usage. Energy derived from the PV systems will not be used to offset ("net") usage prior to calculating charges. This will ensure that utility infrastructure costs will be recovered by the utilities as designed in the applicable retail tariff.
- The utility will provide all energy consumed by the customer. Standby charges for customers with on-site PV systems are not permitted under a VOS rate.
- The rates for usage can be adjusted in future ratemaking.

VOS Components

The definition and selection of VOS components were based on the following considerations:

- Components corresponding to minimum statutory requirements are included. These account for the "value of energy and its delivery, generation capacity, transmission capacity, transmission and distribution line losses, and environmental value."
- Non-required components were selected only if they were based on known and measurable evidence of the cost or benefit of solar operation to the utility.
- Environmental costs are included as a required component, and are based on existing Minnesota and EPA externality costs.
- Avoided fuel costs are based on long-term risk-free fuel supply contracts. This value implicitly includes both the avoided cost of fuel, as well as the avoided cost of price volatility risk that is otherwise passed from the utility to customers through fuel price adjustments.
- Credit for systems installed at high value locations (identified in the legislation as an option) is included as an option for the utility. It is not a separate VOS component but rather is implemented using a location-specific distribution capacity value (the component most affected by location). This is addressed in the Distribution Capacity Cost section.
- Voltage control and solar integration (a cost) are kept as "placeholder" components for future years. Methodologies are not provided, but these components may be developed for the future. Voltage control benefits are anticipated but will first require implementation of recent changes to national interconnection standards. Solar integration costs are expected to be small, but possibly measureable. Further research will be required on this topic.

Table 1 presents the VOS components selected by Commerce and the cost basis for each component. Table 2 presents the VOS components that were considered but not selected by Commerce. Selections were made based on requirements and guidance in the enabling statute, and were informed by stakeholder comments (including those from Minnesota utilities; local and national solar and environmental organizations; local solar manufacturers and installers; and private parties) and workshop discussions. Stakeholders participated in four public workshops and provided comments through workshop panels, workshop Q&A sessions and written comments.

Table 1. VOS components included in methodology.

Value Component	Basis	Legislative Guidance	Notes
Avoided Fuel Cost	Energy market costs (portion attributed to fuel)	Required (energy)	Includes cost of long-term price risk
Avoided Plant O&M Cost	Energy market costs (portion attributed to O&M)	Required (energy)	
Avoided Generation Capacity Cost	Capital cost of generation to meet peak load	Required (capacity)	
Avoided Reserve Capacity Cost	Capital cost of generation to meet planning margins and ensure reliability	Required (capacity)	
Avoided Transmission Capacity Cost	Capital cost of transmission	Required (transmission capacity)	
Avoided Distribution Capacity Cost	Capital cost of distribution	Required (delivery)	
Avoided Environmental Cost	Externality costs	Required (environmental)	
Voltage Control	Cost to regulate distribution (future inverter designs)		Future (TBD)
Integration Cost[3]	Added cost to regulate system frequency with variable solar		Future (TBD)

[3] This is not a value, but a cost. It would reduce the VOS rate if included.

Table 2. VOS components not included in methodology.

Value Component	Basis	Legislative Guidance	Notes
Credit for Local Manufacturing/ Assembly	Local tax revenue tied to net solar jobs	Optional (identified in legislation)	
Market Price Reduction	Cost of wholesale power reduced in response to reduction in demand		
Disaster Recovery	Cost to restore local economy (requires energy storage and islanding inverters)		

Solar Penetration

Solar penetration refers to the total installed capacity of PV on the grid, generally expressed as a percentage of the grid's total load. The level of solar penetration on the grid is important because it affects the calculation of the Effective Load Carrying Capability (ELCC) and Peak Load Reduction (PLR) load-match factors (described later).

In the methodology, the near-term level of PV penetration is used. This is done so that the capacity-related value components will reflect the near-term level of PV penetration on the grid. However, the change in PV penetration level will be accounted for in the annual adjustment to the VOS. To the extent that PV penetration increases, future VOS rates will reflect higher PV penetration levels.

Marginal Fuel

This methodology assumes that PV displaces natural gas during PV operating hours. This is consistent with current and projected MISO market experience. During some hours of the year, other fuels (such as coal) may be the fuel on the margin. In these cases, natural gas displacement is a simplifying assumption that is not expected to materially impact the calculated VOS tariff. However, if future analysis indicates that the assumption is not warranted, then the methodology may be modified accordingly. For example, by changing the methodology to include displacement of coal production, avoided fuel costs may decrease and avoided environmental costs may increase.

Economic Analysis Period

In evaluating the value of a distributed PV resource, the economic analysis period is set at 25 years, the assumed useful service life of the PV system[4]. The methodology includes PV degradation effects as described later.

Annual VOS Tariff Update

Each year, a new VOS tariff would be calculated using current data, and the new resulting VOS rate would be applicable to all customers entering the tariff during the year. Changes such as increased or decreased fuel prices and modified hourly utility load profiles due to higher solar penetration will be incorporated into each new annual calculation.

Customers who have already entered into the tariff in a previous year will not be affected by this annual adjustment. However, customers who have entered into a tariff in prior years will see their Value of Solar rates adjusted for the previous year's inflation rate as described later.

Commerce may also update the methodology to use the best available practices, as necessary.

Transparency Elements

The methodology incorporates two tables that are to be included in a utility's application to the Minnesota PUC for the use of a VOS tariff. These tables are designed to improve transparency and facilitate understanding among stakeholders and regulators.

- **VOS Data Table.** This table provides a utility-specific defined list of the key input assumptions that go into the VOS tariff calculation. This table is described in more detail later.
- **VOS Calculation Table.** This table includes the list of value components and their gross values, their load-match factors, their Loss Savings Factors, and the computation of the total levelized value.

Glossary

A glossary is provided at the end of this document defining some of the key terms used throughout this document.

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[4] [4] NREL: Solar Resource Analysis and High-Penetration PV Potential (April 2010). http://www.nrel.gov/docs/fy10osti/47956.pdf

Methodology: Assumptions

Fixed Assumptions

Table 3 and Table 4 present fixed assumptions, common to all utilities and incorporated into this methodology, that are to be applied to the calculation of 2014 VOS tariffs. These may be updated by Commerce in future years as necessary when performing the annual VOS update. Table 4 is described in more detail in the Avoided Environmental Cost subsection. Table terms can be found in the Glossary.

Published values from the Bureau of Labor and Statistics for the Urban Consumer Price Index (CPI) (ftp://ftp.bls.gov/pub/special.requests/cpi/cpiai.txt) were used to calculate an average annual inflation rate of 2.53% over the last 25 years (see equations below). This was taken as the expected general escalation rate.

$$25yrAvgAnnualInflation = \left(\frac{Nov2013\ UCPI}{Nov1988\ UCPI}\right)^{1/(2013-1988)} - 1 \qquad (1)$$

$$25yrAvgAnnualInflation = \left[\left(\frac{224.939}{120.300}\right)^{1/25} - 1\right] = 2.53\% \qquad (2)$$

The “Guaranteed NG Fuel Price Escalation” value of 4.77%, used as described later to calculate the Avoided Fuel Costs, is calculated from a best fit to the listed NYMEX futures prices (also shown in Table 3). This fit can be seen below in Figure 2.

Figure 2. Fit to NYMEX natural gas futures prices.

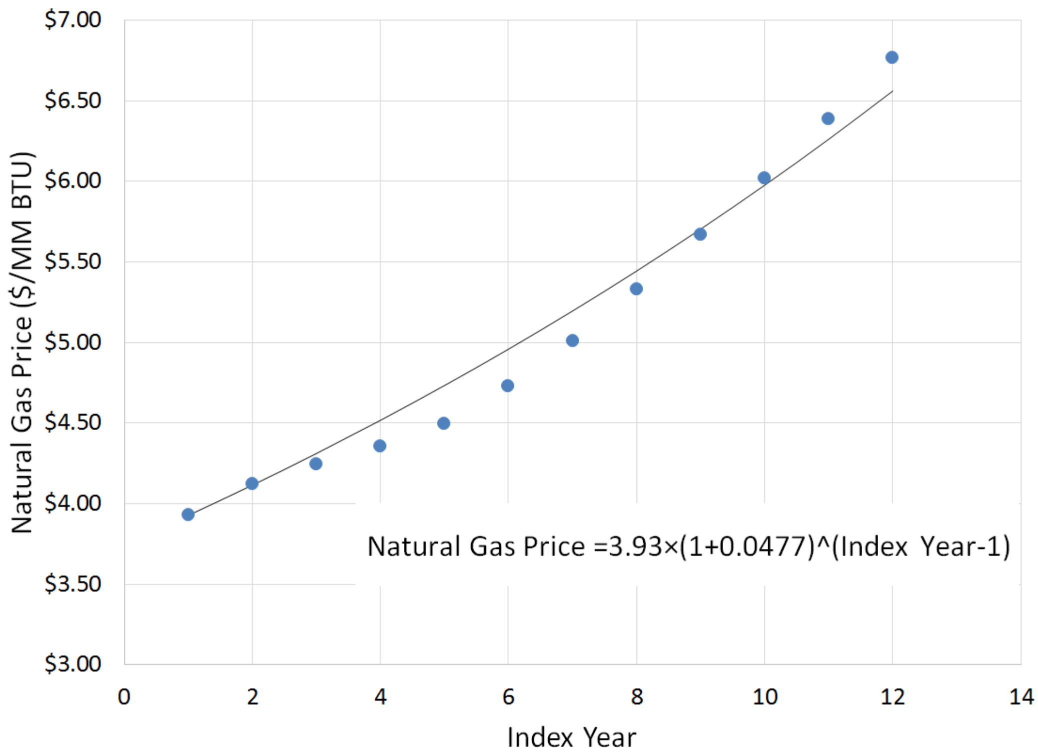

Table 3. Fixed assumptions to be used for 2014 VOS calculations – common to all utilities.

Guaranteed NG Fuel Prices						
Year				**Environmental Externalities**		
2014	$3.93	$ per MMBtu		Environmental discount rate (nominal)	5.61%	per year
2015	$4.12	$ per MMBtu		Environmental costs	(shown in separate table)	
2016	$4.25	$ per MMBtu				
2017	$4.36	$ per MMBtu		**Economic Assumptions**		
2018	$4.50	$ per MMBtu		General escalation rate	2.53%	per year
2019	$4.73	$ per MMBtu				
2020	$5.01	$ per MMBtu				
2021	$5.33	$ per MMBtu		**Treasury Yields**		
2022	$5.67	$ per MMBtu		1 Year	0.13%	
2023	$6.02	$ per MMBtu		2 Year	0.29%	
2024	$6.39	$ per MMBtu		3 Year	0.48%	
2025	$6.77	$ per MMBtu		5 Year	1.01%	
				7 Year	1.53%	
NG fuel price escalation	4.77%			10 Year	2.14%	
				20 Year	2.92%	
PV Assumptions				30 Year	3.27%	
PV degradation rate	0.50%	per year				
PV life	25	years				

Table 4. Fixed environmental externality costs by year.

Year	Analysis Year	CO_2 Cost ($/MMBtu)	PM10 Cost ($/MMBtu)	CO Cost ($/MMBtu)	NO_x Cost ($/MMBtu)	Pb Cost ($/MMBtu)	Total Cost ($/MMBtu)
2014	0	2.140	0.027	0.000	0.044	0.000	2.210
2015	1	2.255	0.028	0.000	0.045	0.000	2.327
2016	2	2.375	0.028	0.000	0.046	0.000	2.449
2017	3	2.499	0.029	0.000	0.047	0.000	2.575
2018	4	2.628	0.030	0.000	0.048	0.000	2.706
2019	5	2.829	0.030	0.000	0.050	0.000	2.909
2020	6	2.970	0.031	0.000	0.051	0.000	3.052
2021	7	3.045	0.032	0.000	0.052	0.000	3.130
2022	8	3.195	0.033	0.000	0.053	0.000	3.282
2023	9	3.351	0.034	0.000	0.055	0.000	3.439
2024	10	3.512	0.034	0.000	0.056	0.000	3.603
2025	11	3.679	0.035	0.000	0.058	0.000	3.772
2026	12	3.853	0.036	0.000	0.059	0.000	3.948
2027	13	4.033	0.037	0.000	0.061	0.000	4.131
2028	14	4.219	0.038	0.000	0.062	0.000	4.320
2029	15	4.413	0.039	0.000	0.064	0.000	4.516
2030	16	4.613	0.040	0.000	0.065	0.000	4.719
2031	17	4.730	0.041	0.000	0.067	0.000	4.839
2032	18	4.944	0.042	0.000	0.069	0.000	5.054
2033	19	5.165	0.043	0.000	0.070	0.000	5.278
2034	20	5.394	0.044	0.000	0.072	0.000	5.510
2035	21	5.631	0.045	0.000	0.074	0.000	5.750
2036	22	5.877	0.047	0.000	0.076	0.000	5.999
2037	23	6.131	0.048	0.000	0.078	0.000	6.257
2038	24	6.395	0.049	0.000	0.080	0.000	6.524

See explanation in the Avoided Environmental Cost section.

Utility-Specific Assumptions and Calculations

Some assumptions and calculations are unique to each utility. These include economic assumptions (such as discount rate) and technical calculations (such as ELCC). Utility-specific assumptions and calculations are determined by the utility, and are included in the VOS Data Table, a required transparency element.

The utility-specific calculations (such as capacity-related transmission capital cost) are determined using the methods described in this methodology.

An example VOS Data Table, showing the parameters to be included in the utility filing for the VOS tariff, is shown in Table 5. This table includes values that are given for example only. These example values carry forward in the example calculations.

Table 5. VOS Data Table (EXAMPLE DATA) — required format showing example parameters used in the example calculations.

	Input Data	Units
Economic Factors		
Start Year for VOS applicability	2014	
Discount rate (WACC)	8.00%	per year
Load Match Analysis (see calculation method)		
ELCC (no loss)	40%	% of rating
PLR (no loss)	30%	% of rating
Loss Savings - Energy	8%	% of PV output
Loss Savings - PLR	5%	% of PV output
Loss Savings - ELCC	9%	% of PV output
PV Energy (see calculation method)		
First year annual energy	1800	kWh per kW-AC
Transmission (see calculation method)		
Capacity-related transmission capital cost	$33	$ per kW-yr

	Input Data	Units
Power Generation		
Peaking CT, simple cycle		
Installed cost	900	$/kW
Heat rate	9,500	BTU/kWh
Intermediate peaking CCGT		
Installed cost	1,200	$/kW
Heat rate	6,500	BTU/kWh
Other		
Solar-weighted heat rate (see calc. method)	8000	BTU per kWh
Fuel Price Overhead	$0.50	$ per MMBtu
Generation life	50	years
Heat rate degradation	0.100%	per year
O&M cost (first Year) - Fixed	$5.00	per kW-yr
O&M cost (first Year) - Variable	$0.0010	$ per kWh
O&M cost escalation rate	2.00%	per year
Reserve planning margin	15%	
Distribution		
Capacity-related distribution capital cost	$200	$ per kW
Distribution capital cost escalation	2.00%	per year
Peak load	5000	MW
Peak load growth rate	1.00%	per year

Methodology: Technical Analysis

Load Analysis Period

The VOS methodology requires that a number of technical parameters (PV energy production, effective load carrying capability (ELCC) 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. For this reason, the load analysis period must cover a period of at least one year.

The data may start on any day of the year, and multiple years may be included, as long as all included years are contiguous and each included year is a complete one-year period. For example, valid load analysis periods may be 1/1/2012 0:00 to 12/31/2012 23:00 or 11/1/2010 0:00 to 10/31/2013 23:00.

Three types of time series data are required to perform the technical analysis:

- **Hourly Generation Load:** the hourly utility load over the Load Analysis Period. This is the sum of utility generation and import power needed to meet all customer load.
- **Hourly Distribution Load:** the hourly distribution load over the Load Analysis Period. The distribution load is the power entering the distribution system from the transmission system (i.e., generation load minus transmission losses).
- **Hourly PV Fleet Production:** the hourly PV Fleet production over the Load Analysis Period. The PV fleet production is the aggregate generation of all of the PV systems in the PV fleet.

All three types of data must be provided as synchronized, time-stamped hourly values of average power over the same period, and corresponding to the same hourly intervals. Data must be available for every hour of the Load Analysis Period.

PV data using Typical Meteorological Year data is not time synchronized with time series production data, so it should not be used as the basis for PV production.

Data that is not in one-hour intervals must be converted to hourly data (for example, 15-minute meter data would have to be combined to obtain 1-hour data). Also, data values that represent energy must be converted to average power.

If data is missing or deemed erroneous for any time period less than or equal to 24 hours, the values corresponding to that period may be replaced with an equal number of values from the same time interval on the previous or next day if it contains valid data. This data replacement method may be used provided that it does not materially affect the results.

PV Energy Production

PV System Rating Convention

The methodology uses a rating convention for PV capacity based on AC delivered energy (not DC), taking into account losses internal to the PV system. A PV system rated output is calculated by multiplying the number of modules by the module PTC rating[5] [as listed by the California Energy Commission (CEC)[6]] to account for module de-rate effects. The result is then multiplied by the CEC-listed inverter efficiency rating[7] to account for inverter efficiency, and the result is multiplied by a loss factor to account for internal PV array losses (wiring losses, module mismatch and other losses).

If no CEC module PTC rating is available, the module PTC rating should be calculated as 0.90 times the module STC rating[8]. If no CEC inverter efficiency rating is available, an inverter efficiency of 0.95 should be used. If no measured or design loss factor is available, 0.85 should be used.

To summarize: [9]

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

Hourly PV Fleet Production

Hourly PV Fleet Production can be obtained using any one of the following three options:

1. Utility Fleet - Metered Production. Fleet production data can be created by combining actual metered production data for every PV system in the utility service territory, provided that there are a sufficient number of systems[10] installed to accurately derive a correct representation of aggregate PV production. Such metered data is to be gross PV output on the AC side of the

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[5] 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 are 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. PV manufacturers use Standard Test Conditions, or STC, to rate their PV products.

[6] CEC module PTC ratings for most modules can be found at: http://www.gosolarcalifornia.ca.gov/equipment/pv_modules.php

[7] CEC inverter efficiency ratings for most inverters can be found at: http://www.gosolarcalifornia.ca.gov/equipment/inverters.php

[8] PV manufacturers use Standard Test Conditions, or STC, to rate their PV products. STC are 1,000 Watts per square meter solar irradiance, 25 degrees C cell temperature, air mass equal to 1.5, and ASTM G173-03 standard spectrum.

[9] In some cases, this equation will have to be adapted to account for multiple module types and/or inverters. In such cases, the rating of each subsystem can be calculated independently and then added.

[10] A sufficient number of systems has been achieved when adding a single system of random orientation, tilt, tracking characteristics, and capacity (within reason) does not materially change the observed hourly PV Fleet Shape (see next subsection of PV Fleet Shape definition).

system, but before local customer loads are subtracted (i.e., PV must be separately metered from load). Metered data from individual systems is then aggregated by summing the measured output for all systems for each one-hour period. For example, if system A has an average power of 4.5 kW-AC from 11:00 AM to 12:00 PM, and system B has an average power of 2.3 kW-AC from 11:00 AM to 12:00 PM, the combined average power for 11:00 AM to 12:00 PM would be 6.8 kW-AC.

2. <u>Utility Fleet, Simulated Production</u>. If metered data is not available, the aggregate output of all distributed PV systems in the utility service territory can be modeled using PV system technical specifications and hourly irradiance and temperature data. These systems must be deployed in sufficient numbers to accurately derive a correct representation of aggregate PV production. Modeling must take into account the system's location and each array's tracking capability (fixed, single-axis or dual-axis tracking), orientation (tilt and azimuth), module PTC ratings, inverter efficiency and power ratings, other loss factors and the effect of temperature on module output. Technical specifications for each system must be available to enable such modeling. Modeling must also make use of location-specific, time-correlated, measured or satellite-derived plane of array irradiance data. Ideally, the software will also support modeling of solar obstructions.
   - To make use of this option, detailed system specifications for every PV system in the utility's service territory must be obtained. At a minimum, system specifications must include:
     - Location (latitude and longitude)
     - System component ratings (e.g., module ratings an inverter ratings)
     - Tilt and azimuth angles
     - Tracking type (if applicable)
   - After simulating the power production for each system for each hour in the Load Analysis Period, power production must be aggregated by summing the power values for all systems for each one-hour period. For example, if system A has an average power of 4.5 kW-AC from 11:00 AM to 12:00 PM, and system B has an average power of 2.3 kW-AC from 11:00 AM to 12:00 PM, the combined average power for 11:00 AM to 12:00 PM would be 6.8 kW-AC.

3. <u>Expected Fleet, Simulated Production</u>. If neither metered production data nor detailed PV system specifications are available, a diverse set of PV resources can be estimated by simulating groups of systems at major load centers in the utility's service territory with some assumed fleet configuration. To use this method, one or more of the largest load centers in the utility service territory may be used. If a single load center accounts for a high percentage of the utility's total load, a single location will suffice. If there are several large load centers in the territory, groups of systems can be created at each location with capacities proportional to the load in that area.
   - For each location, simulate multiple systems, each rated in proportion to the expected capacity, with azimuth and tilt angles such as the list of systems presented in Table 6. Note

that the list of system configurations should represent the expected fleet composition. No method is explicitly provided to determine the expected fleet composition; however, a utility could analyze the fleet composition of PV fleets outside of its territory.

Table 6. (EXAMPLE) Azimuth and tilt angles

System	Azimuth	Tilt	% Capacity
1	90	20	3.5
2	135	15	3.0
3	135	30	6.5
4	180	0	6.0
5	180	15	16.0
6	180	25	22.5
7	180	35	18.0
8	235	15	8.5
9	235	30	9.0
10	270	20	7.0

- Simulate each of the PV systems for each hour in the Load Analysis Period. Aggregate power production for the systems is obtained by summing the power values for each one-hour period. For example, if system A has an average power of 4.5 kW-AC from 11:00 AM to 12:00 PM, and system B has an average power of 2.3 kW-AC from 11:00 AM to 12:00 PM, the combined average power for 11:00 AM to 12:00 PM would be 6.8 kW-AC.
- If the utility elects to perform a location-specific analysis for the Avoided Distribution Capacity Costs, then it should also take into account what the geographical distribution of the expected PV fleet would be. Again, this could be done by analyzing a PV fleet composition outside of the utility's territory. An alternative method that would be acceptable is to distribute the expected PV fleet across major load centers. Thereby assuming that PV capacity is likely to be added where significant load (and customer density) already exists.
- Regardless of location count and location weighting, the total fleet rating is taken as the sum of the individual system ratings.

PV Fleet Shape

Regardless of which of the three methods is selected for obtaining the Hourly PV Fleet production, the next step is divide each hour's value by the PV Fleet's aggregate AC rating to obtain the PV Fleet Shape. The units of the PV Fleet Shape are kWh per hour per kW-AC (or, equivalently, average kW per kW-AC).

Marginal PV Resource

The PV Fleet Shape is hourly production of a Marginal PV Resource having a rating of 1 kW-AC.

Annual Avoided Energy

Annual Avoided Energy (kWh per kW-AC per year) is the sum of the hourly PV Fleet Shape across all hours of the Load Analysis Period, divided by the numbers of years in the Load Analysis Period. The result is the annual output of the Marginal PV Resource.

$$Annual\ Avoided\ Energy\ (kWh) = \frac{\sum Hourly\ PV\ Fleet\ Production_h}{NumberOfYearsInLoadAnalysisPeriod} \tag{3}$$

- Defined in this way, the Annual Avoided Energy does not include the effects of loss savings. As described in the Loss Analysis subsection, however, it will have to be calculated for the two loss cases (with losses and without losses).

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 used:

- Effective Load Carrying Capability (ELCC)
- Peak Load Reduction (PLR)

Near term PV penetration levels are used in the calculation of the ELCC and PLR values so that the capacity-related value components will reflect the near term level of PV penetration on the grid. However, the ELCC and PLR will be re-calculated during the annual VOS adjustment and thus reflect any increase in future PV Penetration Levels.

Effective Load Carrying Capability (ELCC)

The Effective Load Carrying Capability (ELCC) is the measure of the effective capacity for distributed PV that can be applied to the avoided generation capacity costs, the avoided reserve capacity costs, the avoided generation fixed O&M costs, and the avoided transmission capacity costs (see Figure 1).

Using current MISO rules for non-wind variable generation (MISO BPM-011, Section 4.2.2.4, page 35)[11]: the ELCC will be calculated from the PV Fleet Shape for hours ending 2pm, 3pm, and 4pm Central Standard Time during June, July, and August over the most recent three years. If three years of data are unavailable, MISO requires “a minimum of 30 consecutive days of historical data during June, July, or August” for the hours ending 2pm, 3pm and 4pm Central Standard Time.

The ELCC is calculated by averaging the PV Fleet Shape over the specified hours, and then dividing by the rating of the Marginal PV Resource (1 kW-AC), which results in a percentage value. Additionally, the ELCC must be calculated for the two loss cases (with and without T&D losses, as described in the Loss Analysis subsection).

Peak Load Reduction (PLR)

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).

[11] https://www.misoenergy.org/Library/BusinessPracticesManuals/Pages/BusinessPracticesManuals.aspx

Loss Savings Analysis

In order to calculate the required Loss Savings Factors on a marginal basis as described below, it will be necessary to calculate ELCC, PLR and Annual Avoided Energy each twice. They should be calculated first by *including* the effects of avoided marginal losses, and second by *excluding* them. For example, the ELCC would first be calculated by including avoided 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 calculations should observe the following

Table 7. Losses to be considered.

Technical Parameter	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 MISO defined hours.
PLR	Avoided distribution losses (not transmission) at peak.

When calculating avoided marginal losses, the analysis must 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 for use within the VOS Calculation Table:

$$Annual\ Avoided\ Energy_{WithLosses} = Annual\ Avoided\ Energy_{WithoutLosses}\left(1 + Loss\ Savings_{Energy}\right) \quad (4)$$

Equation 3 is then rearranged to solve for the Energy Loss Savings Factor:

$$Loss\ Savings_{Energy} = \frac{Annual\ Avoided\ Energy_{WithLosses}}{Annual\ Avoided\ Energy_{WithoutLosses}} - 1 \quad (5)$$

Similarly, the PLR Loss Savings Factor is defined as:

$$Loss\ Savings_{PLR} = \frac{PLR_{WithLosses}}{PLR_{WithoutLosses}} - 1 \quad (6)$$

and the ELCC Loss Savings Factor is defined as:

$$Loss\ Savings_{ELCC} = \frac{ELCC_{WithLosses}}{ELCC_{WithoutLosses}} - 1 \quad (7)$$

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. These gross component values will then be entered into the VOS Calculation Table, which is the second of the two key transparency elements.

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

By convention, the analysis year 0 corresponds to the year in which the VOS tariff will begin. As an example, if a VOS was done in 2013 for customers entering a VOS tariff between January 1, 2014 and December 31, 2014, then year 0 would be 2014, year 1 would be 2015, and so on.

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

$$DiscountFactor_i = \frac{1}{(1 + DiscountRate)^i} \qquad (8)$$

The *DiscountRate* is the utility Weighted Average Cost of Capital.

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

$$RiskFreeDiscountFactor_i = \frac{1}{(1 + RiskFreeDiscountRate)^i} \qquad (9)$$

The *RiskFreeDiscountRate* is based on the yields of current Treasury securities[12] of 1, 2, 3, 5, 7, 10, 20, and 30 year maturation dates. The *RiskFreeDiscountRate* is used once in the calculation of the Avoided Fuel Costs.

Finally, an environmental discount factor is given by:

$$EnvironmentalDiscountFactor_i = \frac{1}{(1 + EnvironmentalDiscountRate)^i} \qquad (10)$$

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

The *EnvironmentalDiscountRate* is based on the 3% *real* discount rate that has been determined to be an appropriate societal discount rate for future environmental benefits.[13] As the methodology requires a nominal discount rate, this 3% *real* discount rate is converted into its equivalent 5.61% nominal discount rate as follows:[14]

$$NominalDiscountRate = (1 + RealDiscountRate) \times (1 + GeneralEscalationRate) - 1 \qquad (11)$$

The *EnvironmentalDiscountRate* is used once in the calculation of the Avoided Environmental 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:

$$PVProduction_i = PVProduction_0 \times (1 - \mathrm{PVDegradationRate})^i \qquad (12)$$

where PVDegradationRate is the annual rate of PV degradation, assumed to be 0.5% per year – the standard PV module warranty guarantees a maximum of 0.5% power degradation per annum. $PVProduction_0$ is the Annual Avoided Energy for the Marginal PV Resource.

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

$$PVCapacity_i = (1 - \mathrm{PVDegradationRate})^i \qquad (13)$$

Avoided Fuel Cost

Avoided fuel costs are based on long-term, risk-free fuel supply contracts. This value implicitly includes both the avoided cost of fuel as well as the avoided cost of price volatility risk that is otherwise passed from the utility to customers through fuel price adjustments.

PV displaces energy generated from the marginal unit, so it avoids the cost of fuel associated with this generation. Furthermore, the PV system is assumed to have a service life of 25 years, so the uncertainty in fuel price fluctuations is also eliminated over this period. For this reason, the avoided fuel cost must take into account the fuel as if it were purchased under a guaranteed, long term contract.

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[13] http://www.epa.gov/oms/climate/regulations/scc-tsd.pdf
[14] http://en.wikipedia.org/wiki/Nominal_interest_rate

The methodology provides for three options to accomplish this:

- **Futures Market.** This option is described in detail below, and is based on the NYMEX NG futures with a fixed escalation for years beyond the 12-year trading period.
- **Long Term Price Quotation.** This option is identical to the above option, except the input pricing data is based on an actual price quotation from an AA-rated NG supplier to lock in prices for the 25-year guaranteed period.
- **Utility-guaranteed Price.** This is the 25-year fuel price that is guaranteed by the utilities. Tariffs using the utility guaranteed price will include a mechanism for removing the usage fuel adjustment charges and provide fixed prices over the term.

Table 8 presents the calculation of the economic value of avoided fuel costs.

For the Futures Market option, Guaranteed NG prices are calculated as follows. Prices for the first 12 years are based on NYMEX futures, with each monthly price averaged to give a 12-month average in $ per MMBtu. Prices for years beyond this NYMEX limit are calculated by applying the assumed annual NYMEX price escalation. An assumed fuel price overhead amount, escalated by year using the assumed NYMEX price escalation, is added to the fuel price to give the burnertip fuel price.

The first-year solar-weighted heat rate is calculated as follows:

$$SolarWeighedHeatRate_0 = \frac{\sum HeatRate_j \times FleetProduction_j}{\sum FleetProduction_j} \tag{14}$$

where the summation is over all hours *j* of the load analysis period, *HeatRate* is the actual heat rate of the plant on the margin, and *FleetProduction* is the Fleet Production Shape time series.

The solar-weighted heat rate for future years is calculated as:

$$SolarWeighedHeatRate_i = SolarWeighedHeatRate_0 \times (1 - \mathrm{HeatRateDegradationRate})^i \tag{15}$$

The utility price in year *i* is:

$$UtilityPrice_i = \frac{BurnertipFuelPrice_i \times SolarWeighedHeatRate_i}{10^6} \tag{16}$$

where the burnertip price is in $ per MMBtu and the heat rate is in Btu per kWh.

Utility cost is the product of the utility price and the per unit PV production. These costs are then discounted using the risk free discount rate and summed for all years. A risk-free discount rate (fitted to the US Treasury yields shown in Table 3) has been selected to account for the fact that there is no risk in the avoided fuel cost.

The VOS price (shown in red in Table 8) is the levelized amount that results in the same discounted amount as the utility price for the Avoided Fuel Cost component.

Avoided Plant O&M – Fixed

Economic value calculations for fixed plant O&M are presented in Table 9. The first year fixed value is escalated at the O&M escalation rate for future years.

Similarly, PV capacity has an initial value of one during the first year because it is applicable to PV systems installed in the first year. Note that effective capacity (load matching) is handled separately, and this table represents the "ideal" resource, as if PV were able to receive the same capacity credit as a fully dispatchable technology.

Fixed O&M is avoided only when the resource requiring fixed O&M is avoided. For example, if new generation is not needed for two years, then the associated fixed O&M is also not needed for two years. In the example calculation, generation is assumed to be needed for all years, so the avoided cost is calculated for all years.

The utility cost is the fixed O&M cost times the PV capacity divided by the utility capacity. Utility prices are the cost divided by the PV production. Costs are discounted using the utility discount factor and are summed for all years.

The VOS component value is calculated as before such that the discounted total is equal to the discounted utility cost.

Table 8. (EXAMPLE) Economic Value of Avoided Fuel Costs.

				Prices			**Costs**			**Disc. Costs**	
Year	**Guaranteed NG Price**	**Burnertip NG Price**	**Heat Rate**	**Utility**	**VOS**	**p.u. PV Production**	**Utility**	**VOS**	**Discount Factor**	**Utility**	**VOS**
	($/MMBtu)	($/MMBtu)	(Btu/kWh)	($/kWh)	($/kWh)	(kWh)	($)	($)	**(risk free)**	($)	($)
2014	$3.93	$4.43	8000	$0.035	$0.061	1,800	$64	$110	1.000	$64	$110
2015	$4.12	$4.65	8008	$0.037	$0.061	1,791	$67	$110	0.999	$67	$110
2016	$4.25	$4.79	8016	$0.038	$0.061	1,782	$68	$109	0.994	$68	$109
2017	$4.36	$4.93	8024	$0.040	$0.061	1,773	$70	$109	0.986	$69	$107
2018	$4.50	$5.10	8032	$0.041	$0.061	1,764	$72	$108	0.971	$70	$105
2019	$4.73	$5.36	8040	$0.043	$0.061	1,755	$76	$108	0.951	$72	$102
2020	$5.01	$5.67	8048	$0.046	$0.061	1,747	$80	$107	0.927	$74	$99
2021	$5.33	$6.03	8056	$0.049	$0.061	1,738	$84	$107	0.899	$76	$96
2022	$5.67	$6.40	8064	$0.052	$0.061	1,729	$89	$106	0.872	$78	$93
2023	$6.02	$6.78	8072	$0.055	$0.061	1,721	$94	$106	0.842	$79	$89
2024	$6.39	$7.18	8080	$0.058	$0.061	1,712	$99	$105	0.809	$80	$85
2025	$6.77	$7.60	8088	$0.061	$0.061	1,703	$105	$105	0.786	$82	$82
2026	$7.09	$7.96	8097	$0.064	$0.061	1,695	$109	$104	0.762	$83	$79
2027	$7.43	$8.34	8105	$0.068	$0.061	1,686	$114	$104	0.737	$84	$76
2028	$7.78	$8.74	8113	$0.071	$0.061	1,678	$119	$103	0.713	$85	$73
2029	$8.15	$9.16	8121	$0.074	$0.061	1,670	$124	$102	0.688	$85	$70
2030	$8.54	$9.60	8129	$0.078	$0.061	1,661	$130	$102	0.663	$86	$68
2031	$8.95	$10.06	8137	$0.082	$0.061	1,653	$135	$101	0.637	$86	$65
2032	$9.38	$10.54	8145	$0.086	$0.061	1,645	$141	$101	0.612	$86	$62
2033	$9.83	$11.04	8153	$0.090	$0.061	1,636	$147	$100	0.587	$87	$59
2034	$10.29	$11.57	8162	$0.094	$0.061	1,628	$154	$100	0.563	$86	$56
2035	$10.79	$12.12	8170	$0.099	$0.061	1,620	$160	$99	0.543	$87	$54
2036	$11.30	$12.70	8178	$0.104	$0.061	1,612	$167	$99	0.523	$88	$52
2037	$11.84	$13.30	8186	$0.109	$0.061	1,604	$175	$98	0.504	$88	$50
2038	$12.41	$13.94	8194	$0.114	$0.061	1,596	$182	$98	0.485	$88	$48

Validation: Present Value	**$1,999**	**$1,999**

Table 9. (EXAMPLE) Economic value of avoided plant O&M – fixed

Year	O&M Fixed ($/kW)	Utility Capacity (p.u.)	PV Capacity (kW)	p.u. PV Production (kWh)	Costs Utility ($)	Costs VOS ($)	Discount Factor	Disc. Costs Utility ($)	Disc. Costs VOS ($)	Prices Utility ($/kWh)	Prices VOS ($/kWh)
2014	$5.00	1.000	1.000	1800	$5	$6	1.000	$5	$6	$0.003	$0.003
2015	$5.10	0.999	0.995	1791	$5	$6	0.926	$5	$5	$0.003	$0.003
2016	$5.20	0.998	0.990	1782	$5	$6	0.857	$4	$5	$0.003	$0.003
2017	$5.31	0.997	0.985	1773	$5	$6	0.794	$4	$5	$0.003	$0.003
2018	$5.41	0.996	0.980	1764	$5	$6	0.735	$4	$4	$0.003	$0.003
2019	$5.52	0.995	0.975	1755	$5	$6	0.681	$4	$4	$0.003	$0.003
2020	$5.63	0.994	0.970	1747	$5	$6	0.630	$3	$4	$0.003	$0.003
2021	$5.74	0.993	0.966	1738	$6	$6	0.583	$3	$3	$0.003	$0.003
2022	$5.86	0.992	0.961	1729	$6	$6	0.540	$3	$3	$0.003	$0.003
2023	$5.98	0.991	0.956	1721	$6	$6	0.500	$3	$3	$0.003	$0.003
2024	$6.09	0.990	0.951	1712	$6	$6	0.463	$3	$3	$0.003	$0.003
2025	$6.22	0.989	0.946	1703	$6	$6	0.429	$3	$2	$0.003	$0.003
2026	$6.34	0.988	0.942	1695	$6	$6	0.397	$2	$2	$0.004	$0.003
2027	$6.47	0.987	0.937	1686	$6	$6	0.368	$2	$2	$0.004	$0.003
2028	$6.60	0.986	0.932	1678	$6	$6	0.340	$2	$2	$0.004	$0.003
2029	$6.73	0.985	0.928	1670	$6	$6	0.315	$2	$2	$0.004	$0.003
2030	$6.86	0.984	0.923	1661	$6	$6	0.292	$2	$2	$0.004	$0.003
2031	$7.00	0.983	0.918	1653	$7	$5	0.270	$2	$1	$0.004	$0.003
2032	$7.14	0.982	0.914	1645	$7	$5	0.250	$2	$1	$0.004	$0.003
2033	$7.28	0.981	0.909	1636	$7	$5	0.232	$2	$1	$0.004	$0.003
2034	$7.43	0.980	0.905	1628	$7	$5	0.215	$1	$1	$0.004	$0.003
2035	$7.58	0.979	0.900	1620	$7	$5	0.199	$1	$1	$0.004	$0.003
2036	$7.73	0.978	0.896	1612	$7	$5	0.184	$1	$1	$0.004	$0.003
2037	$7.88	0.977	0.891	1604	$7	$5	0.170	$1	$1	$0.004	$0.003
2038	$8.04	0.976	0.887	1596	$7	$5	0.158	$1	$1	$0.005	$0.003

Validation: Present Value	Utility	VOS
	$66	**$66**

Avoided Plant O&M – Variable

An example calculation of avoided plant O&M is displayed in Table 10. Utility prices are given in the VOS Data Table, escalated each year by the O&M escalation rate. As before, the per unit PV production is shown with annual degradation taken into account. The utility cost is the product of the utility price and the per unit production, and these costs are discounted. The VOS price of variable O&M is the levelized value resulting in the same total discounted cost.

Table 10. (EXAMPLE) Economic value of avoided plant O&M – variable.

	Prices			Costs			Disc. Costs	
Year	Utility	VOS	p.u. PV Production	Utility	VOS	Discount Factor	Utility	VOS
	($/kWh)	($/kWh)	(kWh)	($)	($)		($)	($)
2014	$0.0010	$0.0012	1,800	$2	$2	1.000	$2	$2
2015	$0.0010	$0.0012	1,791	$2	$2	0.926	$2	$2
2016	$0.0010	$0.0012	1,782	$2	$2	0.857	$2	$2
2017	$0.0011	$0.0012	1,773	$2	$2	0.794	$1	$2
2018	$0.0011	$0.0012	1,764	$2	$2	0.735	$1	$2
2019	$0.0011	$0.0012	1,755	$2	$2	0.681	$1	$1
2020	$0.0011	$0.0012	1,747	$2	$2	0.630	$1	$1
2021	$0.0011	$0.0012	1,738	$2	$2	0.583	$1	$1
2022	$0.0012	$0.0012	1,729	$2	$2	0.540	$1	$1
2023	$0.0012	$0.0012	1,721	$2	$2	0.500	$1	$1
2024	$0.0012	$0.0012	1,712	$2	$2	0.463	$1	$1
2025	$0.0012	$0.0012	1,703	$2	$2	0.429	$1	$1
2026	$0.0013	$0.0012	1,695	$2	$2	0.397	$1	$1
2027	$0.0013	$0.0012	1,686	$2	$2	0.368	$1	$1
2028	$0.0013	$0.0012	1,678	$2	$2	0.340	$1	$1
2029	$0.0013	$0.0012	1,670	$2	$2	0.315	$1	$1
2030	$0.0014	$0.0012	1,661	$2	$2	0.292	$1	$1
2031	$0.0014	$0.0012	1,653	$2	$2	0.270	$1	$1
2032	$0.0014	$0.0012	1,645	$2	$2	0.250	$1	$0
2033	$0.0015	$0.0012	1,636	$2	$2	0.232	$1	$0
2034	$0.0015	$0.0012	1,628	$2	$2	0.215	$1	$0
2035	$0.0015	$0.0012	1,620	$2	$2	0.199	$0	$0
2036	$0.0015	$0.0012	1,612	$2	$2	0.184	$0	$0
2037	$0.0016	$0.0012	1,604	$3	$2	0.170	$0	$0
2038	$0.0016	$0.0012	1,596	$3	$2	0.158	$0	$0

Validation: Present Value	$24	$24

Avoided Generation Capacity Cost

The solar-weighted capacity cost is based on the installed capital cost of a peaking combustion turbine and the installed capital cost of a combined cycle gas turbine, interpolated based on heat rate:

$$Cost = Cost_{CCGT} + (HeatRate_{PV} - HeatRate_{CCGT}) \times \frac{Cost_{CT} - Cost_{CCGT}}{HeatRate_{CT} - HeatRate_{CCGT}} \qquad (17)$$

Where $HeatRate_{PV}$ is the solar-weighted heat rate calculated in equation (14).

Using equation (17) with the CT/CCGT heat rates and costs from the example VOS Data Table, we calculated a solar-weighted capacity cost of $1,050 per kW. In the example, the amortized cost is $86 per kW-yr.

Table 11 illustrates how utility costs are calculated by taking into account the degrading heat rate of the marginal unit and PV. For example, in year 2015, the utility cost is $86 per kW-yr x 0.999 / 0.995 to give $85 for each unit of effective PV capacity. Utility prices are back-calculated for reference from the per unit PV production. Again, the VOS price is selected to give the same total discounted cost as the utility costs for the Generation Capacity Cost component.

Table 11. (EXAMPLE) Economic value of avoided generation capacity cost.

Year	Capacity Cost	Utility Capacity	PV Capacity	p.u. PV Production	Costs Utility	Costs VOS	Discount Factor	Disc. Costs Utility	Disc. Costs VOS	Prices Utility	Prices VOS
	($/kW-yr)	(p.u.)	(kW)	(kWh)	($)	($)		($)	($)	($/kWh)	($/kWh)
2014	$86	1.000	1.000	1800	$86	$87	1.000	$86	$87	$0.048	$0.048
2015	$86	0.999	0.995	1791	$85	$86	0.926	$79	$80	$0.048	$0.048
2016	$86	0.998	0.990	1782	$85	$86	0.857	$73	$73	$0.048	$0.048
2017	$86	0.997	0.985	1773	$85	$85	0.794	$67	$68	$0.048	$0.048
2018	$86	0.996	0.980	1764	$84	$85	0.735	$62	$62	$0.048	$0.048
2019	$86	0.995	0.975	1755	$84	$84	0.681	$57	$57	$0.048	$0.048
2020	$86	0.994	0.970	1747	$84	$84	0.630	$53	$53	$0.048	$0.048
2021	$86	0.993	0.966	1738	$83	$84	0.583	$49	$49	$0.048	$0.048
2022	$86	0.992	0.961	1729	$83	$83	0.540	$45	$45	$0.048	$0.048
2023	$86	0.991	0.956	1721	$83	$83	0.500	$41	$41	$0.048	$0.048
2024	$86	0.990	0.951	1712	$82	$82	0.463	$38	$38	$0.048	$0.048
2025	$86	0.989	0.946	1703	$82	$82	0.429	$35	$35	$0.048	$0.048
2026	$86	0.988	0.942	1695	$82	$81	0.397	$32	$32	$0.048	$0.048
2027	$86	0.987	0.937	1686	$81	$81	0.368	$30	$30	$0.048	$0.048
2028	$86	0.986	0.932	1678	$81	$81	0.340	$28	$27	$0.048	$0.048
2029	$86	0.985	0.928	1670	$81	$80	0.315	$25	$25	$0.048	$0.048
2030	$86	0.984	0.923	1661	$80	$80	0.292	$23	$23	$0.048	$0.048
2031	$86	0.983	0.918	1653	$80	$79	0.270	$22	$21	$0.049	$0.048
2032	$86	0.982	0.914	1645	$80	$79	0.250	$20	$20	$0.049	$0.048
2033	$86	0.981	0.909	1636	$80	$79	0.232	$18	$18	$0.049	$0.048
2034	$86	0.980	0.905	1628	$79	$78	0.215	$17	$17	$0.049	$0.048
2035	$86	0.979	0.900	1620	$79	$78	0.199	$16	$15	$0.049	$0.048
2036	$86	0.978	0.896	1612	$79	$77	0.184	$14	$14	$0.049	$0.048
2037	$86	0.977	0.891	1604	$78	$77	0.170	$13	$13	$0.049	$0.048
2038	$86	0.976	0.887	1596	$78	$77	0.158	$12	$12	$0.049	$0.048
					Validation: Present Value			**$958**	**$958**		

Avoided Reserve Capacity Cost

An example of the calculation of avoided reserve capacity cost is shown in Table 12. This is identical to the generation capacity cost calculation, except utility costs are multiplied by the reserve capacity margin. In the example, the reserve capacity margin is 15%, so the utility cost for 2014 is calculated as $86 per unit effective capacity x 15% = $13. The rest of the calculation is identical to the capacity cost calculation.

Avoided Transmission Capacity Cost

Avoided transmission costs are calculated the same way as avoided generation costs except in two ways. First, transmission capacity is assumed not to degrade over time (PV degradation is still accounted for). Second, avoided transmission capacity costs are calculated based on the utility's 5-year average MISO OATT Schedule 9 charge in Start Year USD, e.g., in 2014 USD if year one of the VOS tariff was 2014. Table 13 shows the example calculation.

Table 12. (EXAMPLE) Economic value of avoided reserve capacity cost.

Year	Capacity Cost	Gen. Capacity	PV Capacity	p.u. PV Production	Costs		Discount Factor	Disc. Costs		Prices	
					Utility	VOS		Utility	VOS	Utility	VOS
	($/kW-yr)	(p.u.)	(kW)	(kWh)	($)	($)		($)	($)	($/kWh)	($/kWh)
2014	$86	1.000	1.000	1800	$13	$13	1.000	$13	$13	$0.007	$0.007
2015	$86	0.999	0.995	1791	$13	$13	0.926	$12	$12	$0.007	$0.007
2016	$86	0.998	0.990	1782	$13	$13	0.857	$11	$11	$0.007	$0.007
2017	$86	0.997	0.985	1773	$13	$13	0.794	$10	$10	$0.007	$0.007
2018	$86	0.996	0.980	1764	$13	$13	0.735	$9	$9	$0.007	$0.007
2019	$86	0.995	0.975	1755	$13	$13	0.681	$9	$9	$0.007	$0.007
2020	$86	0.994	0.970	1747	$13	$13	0.630	$8	$8	$0.007	$0.007
2021	$86	0.993	0.966	1738	$13	$13	0.583	$7	$7	$0.007	$0.007
2022	$86	0.992	0.961	1729	$12	$12	0.540	$7	$7	$0.007	$0.007
2023	$86	0.991	0.956	1721	$12	$12	0.500	$6	$6	$0.007	$0.007
2024	$86	0.990	0.951	1712	$12	$12	0.463	$6	$6	$0.007	$0.007
2025	$86	0.989	0.946	1703	$12	$12	0.429	$5	$5	$0.007	$0.007
2026	$86	0.988	0.942	1695	$12	$12	0.397	$5	$5	$0.007	$0.007
2027	$86	0.987	0.937	1686	$12	$12	0.368	$4	$4	$0.007	$0.007
2028	$86	0.986	0.932	1678	$12	$12	0.340	$4	$4	$0.007	$0.007
2029	$86	0.985	0.928	1670	$12	$12	0.315	$4	$4	$0.007	$0.007
2030	$86	0.984	0.923	1661	$12	$12	0.292	$4	$3	$0.007	$0.007
2031	$86	0.983	0.918	1653	$12	$12	0.270	$3	$3	$0.007	$0.007
2032	$86	0.982	0.914	1645	$12	$12	0.250	$3	$3	$0.007	$0.007
2033	$86	0.981	0.909	1636	$12	$12	0.232	$3	$3	$0.007	$0.007
2034	$86	0.980	0.905	1628	$12	$12	0.215	$3	$3	$0.007	$0.007
2035	$86	0.979	0.900	1620	$12	$12	0.199	$2	$2	$0.007	$0.007
2036	$86	0.978	0.896	1612	$12	$12	0.184	$2	$2	$0.007	$0.007
2037	$86	0.977	0.891	1604	$12	$12	0.170	$2	$2	$0.007	$0.007
2038	$86	0.976	0.887	1596	$12	$12	0.158	$2	$2	$0.007	$0.007

Validation: Present Value	$144	$144

Table 13. (EXAMPLE) Economic value of avoided transmission capacity cost.

Year	Capacity Cost	Trans. Capacity	PV Capacity	p.u. PV Production	Costs Utility	Costs VOS	Discount Factor	Disc. Costs Utility	Disc. Costs VOS	Prices Utility	Prices VOS
	($/kW-yr)	(p.u.)	(kW)	(kWh)	($)	($)		($)	($)	($/kWh)	($/kWh)
2014	$33	1.000	1.000	1800	$33	$33	1.000	$33	$33	$0.018	$0.018
2015	$33	1.000	0.995	1791	$33	$33	0.926	$30	$30	$0.018	$0.018
2016	$33	1.000	0.990	1782	$33	$33	0.857	$28	$28	$0.018	$0.018
2017	$33	1.000	0.985	1773	$33	$33	0.794	$26	$26	$0.018	$0.018
2018	$33	1.000	0.980	1764	$32	$32	0.735	$24	$24	$0.018	$0.018
2019	$33	1.000	0.975	1755	$32	$32	0.681	$22	$22	$0.018	$0.018
2020	$33	1.000	0.970	1747	$32	$32	0.630	$20	$20	$0.018	$0.018
2021	$33	1.000	0.966	1738	$32	$32	0.583	$19	$19	$0.018	$0.018
2022	$33	1.000	0.961	1729	$32	$32	0.540	$17	$17	$0.018	$0.018
2023	$33	1.000	0.956	1721	$32	$32	0.500	$16	$16	$0.018	$0.018
2024	$33	1.000	0.951	1712	$31	$31	0.463	$15	$15	$0.018	$0.018
2025	$33	1.000	0.946	1703	$31	$31	0.429	$13	$13	$0.018	$0.018
2026	$33	1.000	0.942	1695	$31	$31	0.397	$12	$12	$0.018	$0.018
2027	$33	1.000	0.937	1686	$31	$31	0.368	$11	$11	$0.018	$0.018
2028	$33	1.000	0.932	1678	$31	$31	0.340	$10	$10	$0.018	$0.018
2029	$33	1.000	0.928	1670	$31	$31	0.315	$10	$10	$0.018	$0.018
2030	$33	1.000	0.923	1661	$30	$30	0.292	$9	$9	$0.018	$0.018
2031	$33	1.000	0.918	1653	$30	$30	0.270	$8	$8	$0.018	$0.018
2032	$33	1.000	0.914	1645	$30	$30	0.250	$8	$8	$0.018	$0.018
2033	$33	1.000	0.909	1636	$30	$30	0.232	$7	$7	$0.018	$0.018
2034	$33	1.000	0.905	1628	$30	$30	0.215	$6	$6	$0.018	$0.018
2035	$33	1.000	0.900	1620	$30	$30	0.199	$6	$6	$0.018	$0.018
2036	$33	1.000	0.896	1612	$30	$30	0.184	$5	$5	$0.018	$0.018
2037	$33	1.000	0.891	1604	$29	$29	0.170	$5	$5	$0.018	$0.018
2038	$33	1.000	0.887	1596	$29	$29	0.158	$5	$5	$0.018	$0.018

Validation: Present Value	Utility	VOS
	$365	**$365**

Avoided Distribution Capacity Cost

Avoided distribution capacity costs may be calculated in either of two ways:

- **System-wide Avoided Costs**. These are calculated using utility-wide costs and lead to a VOS rate that is "averaged" and applicable to all solar customers. This method is described below in the methodology.

- **Location-specific Avoided Costs**. These are calculated using location-specific costs, growth rates, etc., and lead to location-specific VOS rates. This method provides the utility with a means for offering a higher-value VOS rate in areas where capacity is most needed (areas of highest value). The details of this method are site specific and not included in the methodology, however they are to be implemented in accordance with the requirements set for the below.

System-wide Avoided Costs

System wide costs and peak growth rates are determined using actual 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 such, the capacity-related percentages shown in Table 14 will be utility specific.

Table 14. (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, and dividing by the kW increase in peak annual load over the 10 years.

Future growth in peak load is assumed to be at the same rate as the last 10 years. It is calculated using the ratio of peak loads of the most recent year (year 10) and the peak load from the earlier year (year 1):

$$GrowthRate = \left(\frac{P_{10}}{P_1}\right)^{1/10} - 1 \qquad (18)$$

A sample economic value calculation is presented in Table 15. The distribution cost for the first year ($200 per kW in the example) is taken from the analysis of historical cost and growth as described above. This cost is escalated each year using the rate in the VOS Data Table.

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. The total discounted cost is calculated ($149M) and amortized over the 25 years.

PV is assumed to be installed in sufficient capacity to allow this investment stream to be deferred for one year. The total discounted cost of the deferred time series is calculated ($140M) and amortized.

Utility 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 utility cost for 2022 is ($14M - $13M)/54MW x 1000 W/kW = $14 per effective kW of PV. As before, utility prices are back-calculated using PV production, and the VOS component rate is calculated such that the total discounted amount equals the discounted utility cost.

Location-specific Avoided Costs

As an alternative to system-wide costs for distribution, location-specific costs may be used. When calculating location-specific costs, the calculation should follow the same method of the system-wide avoided cost method, but use local technical and cost data. The calculation should satisfy the following requirements:

- The distribution cost VOS should be calculated for each distribution planning area, defined as the minimum area in which capacity needs cannot be met by transferring loads internally from one circuit to another.
- Distribution loads (the sum of all relevant feeders), peak load growth rates and capital costs should be based on the distribution planning area.
- Local Fleet Production Shapes may be used, if desired. Alternatively, the system-level Fleet Production Shape may be used.

- Anticipated capital costs should be evaluated based on capacity related investments only (as above) using budgetary engineering cost estimates. All anticipated capital investments in the planning area should be included. Planned capital investments should be assumed to meet capacity requirements for the number of years defined by the amount of new capacity added (in MW) divided by the local growth rate (MW per year). Beyond this time period, which is beyond the planning horizon, new capacity investments should be assumed each year using the system-wide method.
- Planning areas for which engineering cost estimates are not available may be combined, and the VOS calculated using the system-wide method.

Table 15. (EXAMPLE) Economic value of avoided distribution capacity cost, system-wide.

		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	

CONTINUED Table 15. (EXAMPLE) Economic value of avoided distribution capacity cost, system-wide.

Year	p.u. PV Production	Costs Utility	Costs VOS	Discount Factor	Disc. Costs Utility	Disc. Costs VOS	Prices Utility	Prices 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

Avoided Environmental Cost

Environmental costs are included as a required component and are based on existing Minnesota and EPA externality costs. CO_2 and non-CO_2 natural gas emissions factors (lb per MM BTU of natural gas) are taken from the EPA[15] and NaturalGas.org,[16] both of which have nearly identical numbers for the emissions factors. Avoided environmental costs are based on the federal social cost of CO_2 emissions[17] plus the Minnesota PUC-established externality costs for non-CO_2 emissions[18].

The externality cost of CO_2 emissions shown in Table 4 are calculated as follows. The EPA Social Cost of Carbon (CO_2) estimated for a given year is published in 2007 dollars per metric ton. These costs are adjusted for inflation (converted to current dollars), converted to dollars per short ton, and then converted to cost per unit fuel consumption using the assumed values in Table 16.

For example, the EPA externality cost for 2020 (3.0% discount rate, average) is $43 per metric ton of CO_2 emissions in 2007 dollars. This is converted to current dollars by multiplying by a CPI adjustment factor; for 2014, the CPI adjustment factor is of 1.12. The resulting CO_2 costs per metric ton in current dollars are then converted to dollars per short ton by dividing by 1.102. Finally, the costs are escalated using the general escalation rate of 2.53% per year to give $50.77 per ton. Which equates to $51.22 per ton of CO_2, divided by 2000 pounds per ton, and multiplied by 117.0 pounds of CO_2 per MMBtu = $2.970 per MMBtu in 2020 dollars.

Table 16. Natural Gas Emissions.

	NG Emissions (lb/MMBtu)
PM10	0.007
CO	0.04
NOX	0.092
Pb	0.00
CO2	117.0

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[15] http://www.epa.gov/climatechange/ghgemissions/ind-assumptions.html and http://www.epa.gov/ttnchie1/ap42/

[16] http://www.naturalgas.org/environment/naturalgas.asp

[17] See http://www.epa.gov/climatechange/EPAactivities/economics/scc.html, EPA technical document appendix, May 2013.

[18] "Notice of Updated Environmental Externality Values," issued June 5, 2013, PUC docket numbers E-999/CI-93-583 and E-999/CI-00-1636.

All pollutants other than CO_2 are calculated using the Minnesota externality costs using the following method. Externality costs are taken as the midpoint of the low and high values for the urban scenario, adjusted to current dollars, and converted to a fuel-based value using Table 16.

For example, MN's published costs for PM10 are $6,291 per ton (low case) and $9,056 per ton (high case). These are averaged to be ($6291+$9056)/2 = $7674 per ton of PM10 emissions. For 2020, these are escalated using the general escalation rate of 2.53% per year to $8,917 per ton. Which equates to $8,917 per ton of PM10, divided by 2000 pounds per ton, multiplied by 0.007 pounds of PM10 per MMBtu = $0.031 per MMBtu. Similar calculations are done for the other pollutants.

In the example shown in Table 17, the environmental cost is the sum of the costs of all pollutants. For example, in 2020, the total cost of $3.052 per MMBtu corresponds to the 2020 total cost in Table 4. This cost is multiplied by the heat rate for the year (see Avoided Fuel Cost calculation) and divided by 10^6 (to convert Btus to MMBtus), which results in the environmental cost in dollars per kWh for each year. The remainder of the calculation follows the same method as the avoided variable O&M costs but using the environmental discount factor (see Discount Factors for a description of the environmental discount factor and its calculation).

Avoided Voltage Control Cost

This is reserved for future updates to the methodology.

Solar Integration Cost

This is reserved for future updates to the methodology.

Table 17. (EXAMPLE) Economic value of avoided environmental cost.

Year	Env. Cost	Heat Rate	Prices		p.u. PV	Costs		Discount	Disc. Costs	
			Utility	VOS	Production	Utility	VOS	Factor	Utility	VOS
	($/MMBtu)	(Btu/kWh)	($/kWh)	($/kWh)	(kWh)	($)	($)		($)	($)
2014	2.210	8000	$0.018	$0.029	1,800	$32	$52	1.000	$32	$52
2015	2.327	8008	$0.019	$0.029	1,791	$33	$52	0.947	$32	$49
2016	2.449	8016	$0.020	$0.029	1,782	$35	$52	0.897	$31	$46
2017	2.575	8024	$0.021	$0.029	1,773	$37	$51	0.849	$31	$44
2018	2.706	8032	$0.022	$0.029	1,764	$38	$51	0.804	$31	$41
2019	2.909	8040	$0.023	$0.029	1,755	$41	$51	0.761	$31	$39
2020	3.052	8048	$0.025	$0.029	1,747	$43	$51	0.721	$31	$36
2021	3.130	8056	$0.025	$0.029	1,738	$44	$50	0.682	$30	$34
2022	3.282	8064	$0.026	$0.029	1,729	$46	$50	0.646	$30	$32
2023	3.439	8072	$0.028	$0.029	1,721	$48	$50	0.612	$29	$30
2024	3.603	8080	$0.029	$0.029	1,712	$50	$50	0.579	$29	$29
2025	3.772	8088	$0.031	$0.029	1,703	$52	$49	0.549	$29	$27
2026	3.948	8097	$0.032	$0.029	1,695	$54	$49	0.519	$28	$25
2027	4.131	8105	$0.033	$0.029	1,686	$56	$49	0.492	$28	$24
2028	4.320	8113	$0.035	$0.029	1,678	$59	$49	0.466	$27	$23
2029	4.516	8121	$0.037	$0.029	1,670	$61	$48	0.441	$27	$21
2030	4.719	8129	$0.038	$0.029	1,661	$64	$48	0.417	$27	$20
2031	4.839	8137	$0.039	$0.029	1,653	$65	$48	0.395	$26	$19
2032	5.054	8145	$0.041	$0.029	1,645	$68	$48	0.374	$25	$18
2033	5.278	8153	$0.043	$0.029	1,636	$70	$47	0.354	$25	$17
2034	5.510	8162	$0.045	$0.029	1,628	$73	$47	0.336	$25	$16
2035	5.750	8170	$0.047	$0.029	1,620	$76	$47	0.318	$24	$15
2036	5.999	8178	$0.049	$0.029	1,612	$79	$47	0.301	$24	$14
2037	6.257	8186	$0.051	$0.029	1,604	$82	$46	0.285	$23	$13
2038	6.524	8194	$0.053	$0.029	1,596	$85	$46	0.270	$23	$12

Validation: Present Value	**$697**	**$697**

VOS Example Calculation

The economic value, load match, distributed loss savings, and distributed PV value are combined in the required VOS Levelized Calculation Chart. An example is presented in Figure 3 using the assumptions made for the example calculation. Actual VOS results will differ from those shown in the example, but utilities will include in their application a VOS Levelized Calculation Chart in the same format. For completeness, Figure 4 (not required of the utilities) is presented showing graphically the relative importance of the components in the example.

Figure 3. (EXAMPLE) VOS Levelized Calculation Chart (Required).

25 Year Levelized Value	Gross Starting Value ($/kWh)	×	Load Match Factor (%)	× (1 +	Loss Savings Factor (%)	) =	Distributed PV Value ($/kWh)
Avoided Fuel Cost	$0.061				8%		$0.066
Avoided Plant O&M - Fixed	$0.003		40%		9%		$0.001
Avoided Plant O&M - Variable	$0.001				8%		$0.001
Avoided Gen Capacity Cost	$0.048		40%		9%		$0.021
Avoided Reserve Capacity Cost	$0.007		40%		9%		$0.003
Avoided Trans. Capacity Cost	$0.018		40%		9%		$0.008
Avoided Dist. Capacity Cost	$0.008		30%		5%		$0.003
Avoided Environmental Cost	$0.029				8%		$0.031
Avoided Voltage Control Cost							
Solar Integration Cost							
							$0.135

Having calculated the levelized VOS credit, an inflation-adjusted VOS can then be found. An EXAMPLE inflation-adjusted VOS is provided in Figure 5 by using the general escalation rate as the annual inflation rate for all years of the analysis period. Both the inflation-adjusted VOS and the levelized VOS in Figure 5 represent the same long-term value. The methodology requires that the inflation-adjusted (nominal) VOS be used and updated annually to account for the current year's inflation rate.

To calculate the inflation-adjusted VOS for the first year, the products of the levelized VOS, PV production and the discount factor are summed for each year of the analysis period and then divided by the sum of the products of the escalation factor, PV production, and the discount factor for each year of the analysis period, as shown below in Equation (19).

Figure 4. (EXAMPLE) Levelized value components.

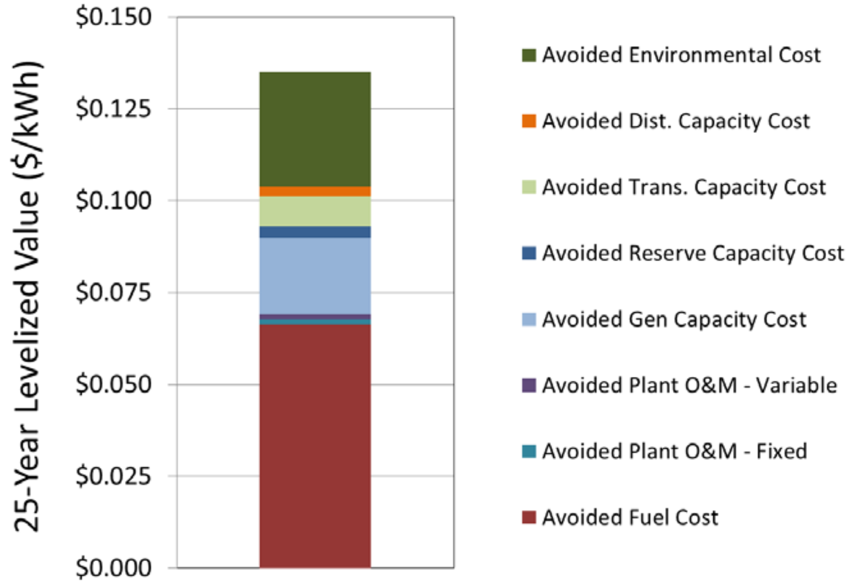
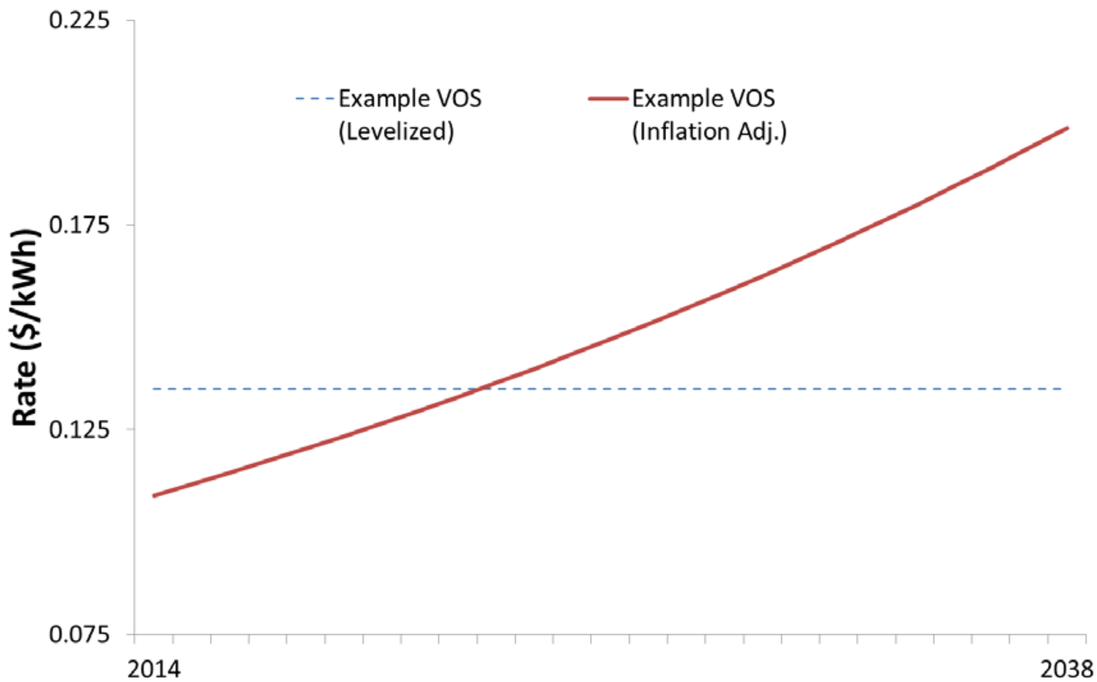


Figure 5. (EXAMPLE) Inflation-Adjusted VOS.



$$InflationAdjustedVOS_{Year0}\left(\frac{\$}{kWh}\right) \tag{19}$$

$$= \frac{\sum_i LevelizedVOS \times PVProduction_i \times DiscountFactor_i}{\sum_i EscalationFactor_i \times PVProduction_i \times DiscountFactor_i}$$

Once the first-year inflation-adjusted VOS is calculated, the value will then be updated on an annual basis in accordance with the observed inflation-rate. Table 18 provides the calculation of the EXAMPLE inflation-adjusted VOS shown in Figure 5. In this EXAMPLE, the inflation rate in future years is set equal to the general escalation rate of 2.53%.

Table 18. (EXAMPLE) Calculation of inflation-adjusted VOS.

Year	Discount Factor	PV Production (kWh)	Escalation Factor	Example VOS (Levelized)	Disc. Cost ($)	Example VOS (Inflation Adj.)	Disc. Cost ($)
2014	1.000	1800	1.000	0.135	243	0.109	196
2015	0.926	1791	1.025	0.135	224	0.112	185
2016	0.857	1782	1.051	0.135	206	0.115	175
2017	0.794	1773	1.078	0.135	190	0.117	165
2018	0.735	1764	1.105	0.135	175	0.120	156
2019	0.681	1755	1.133	0.135	161	0.123	147
2020	0.630	1747	1.162	0.135	149	0.127	139
2021	0.583	1738	1.192	0.135	137	0.130	132
2022	0.540	1729	1.222	0.135	126	0.133	124
2023	0.500	1721	1.253	0.135	116	0.136	117
2024	0.463	1712	1.284	0.135	107	0.140	111
2025	0.429	1703	1.317	0.135	99	0.143	105
2026	0.397	1695	1.350	0.135	91	0.147	99
2027	0.368	1686	1.385	0.135	84	0.151	94
2028	0.340	1678	1.420	0.135	77	0.155	88
2029	0.315	1670	1.456	0.135	71	0.159	83
2030	0.292	1661	1.493	0.135	65	0.163	79
2031	0.270	1653	1.530	0.135	60	0.167	74
2032	0.250	1645	1.569	0.135	56	0.171	70
2033	0.232	1636	1.609	0.135	51	0.175	66
2034	0.215	1628	1.650	0.135	47	0.180	63
2035	0.199	1620	1.692	0.135	43	0.184	59
2036	0.184	1612	1.735	0.135	40	0.189	56
2037	0.170	1604	1.779	0.135	37	0.194	53
2038	0.158	1596	1.824	0.135	34	0.199	50
					2689		2689

Glossary

Table 19. Input data definitions

Input Data	Used in Methodology Section	Definition
Annual Energy	PV Energy Production	The annual PV production (kWh per year) per Marginal PV Resource (initially 1 kW-AC) in the first year (before any PV degradation) of the marginal PV resource. This is calculated in the Annual Energy section of PV Energy Production and used in the Equipment Degradation section.
Capacity-related distribution capital cost	Avoided Distribution Capacity Cost	This is described more fully in the Avoided Distribution Capacity Cost section.
Capacity-related transmission capital cost	Avoided Transmission Capacity Cost	The cost per kW of new construction of transmission, including lines, towers, insulators, transmission substations, etc. Only capacity-related costs should be included.
Discount rate (WACC)	Multiple	The utility's weighted average cost of capital, including interest on bonds and shareholder return.
Distribution capital cost escalation	Avoided Distribution Capacity Cost	Used to calculate future distribution costs.
ELCC (no loss), PLR (no loss)	Load Match Factors	The "Effective Load Carrying Capability" and the "Peak Load Reduction" of a PV resource expressed as percentages of rated capacity (kW-AC). These are described more fully in the Load Match section.
Environmental Costs	Avoided Environmental Cost	The costs required to calculate environmental impacts of conventional generation. These are described more fully in the Avoided Environmental Cost section

Input Data	Used in Methodology Section	Definition
Environmental Discount Rate	Avoided Environmental Cost	The societal discount rate corresponding to the EPA future year cost data, used to calculate the present value of future environmental costs.
Fuel Price Overhead	Avoided Fuel Cost	The difference in cost of fuel as delivered to the plant and the cost of fuel as available in market prices. This cost reflects transmission, delivery, and taxes.
General escalation rate	Avoided Environmental Cost, Example Results	The annual escalation rate corresponding to the most recent 25 years of CPI index data[19], used to convert constant dollar environmental costs into current dollars and to translate levelized VOS into inflation-adjusted VOS.
Generation Capacity Degradation	Avoided Generation Capacity Cost	The percentage decrease in the generation capacity per year
Generation Life	Avoided Generation Capacity Cost	The assumed service life of new generation assets.
Guaranteed NG Fuel Price Escalation	Avoided Fuel Cost	The escalation value to be applied for years in which futures prices are not available.
Guaranteed NG Fuel Prices	Avoided Fuel Cost	The annual average prices to be used when the utility elects to use the Futures Market option. These are not applicable when the utility elects to use options other than the Futures Market option. They are calculated as the annual average of monthly NYMEX NG futures[20], updated 8/27/2013.

[19] www.bls.gov

[20] See for example http://futures.tradingcharts.com/marketquotes/NG.html.

Input Data	Used in Methodology Section	Definition
Heat rate degradation	Avoided Generation Capacity Cost	The percentage increase in the heat rate (BTU per kWh) per year
Installed cost and heat rate for CT and CCGT	Avoided Generation Capacity Cost	The capital costs for these units (including all construction costs, land, ad valorem taxes, etc.) and their heat rates.
Loss Savings (Energy, PLR, and ELCC)	Loss Savings Analysis	The additional savings associated with Energy, PRL and ELCC, expressed as a percentage. These are described more fully in the Loss Savings section.
O&M cost escalation rate	Avoided Plant O&M – Fixed, Avoided Plant O&M – Variable	Used to calculate future O&M costs.
O&M fixed costs	Avoided Plant O&M – Fixed	The costs to operate and maintain the plant that are not dependent on the amount of energy generated.
O&M variable costs	Avoided Plant O&M – Variable	The costs to operate and maintain the plant (excluding fuel costs) that are dependent on the amount of energy generated.
Peak Load	Avoided Distribution Capacity Cost	The utility peak load as expected in the year prior to the VOS start year.
Peak load growth rate	Avoided Distribution Capacity Cost	This is described more fully in the Avoided Distribution Capacity Cost section.
PV Degradation	Equipment Degradation Factors	The reduction in percent per year of PV capacity and PV energy due to degradation of the modules. The value of 0.5 percent is the median value of 2000 observed degradation rates.[21]

[21] D. Jordan and S. Kurtz, "Photovoltaic Degradation Rates – An Analytical Review," NREL, June 2012.

Input Data	Used in Methodology Section	Definition
PV Life	Multiple	The assumed service life of PV. This value is also used to define the study period for which avoided costs are determined and the period over which the VOS rate would apply.
Reserve planning margin	Avoided Reserve Capacity Cost	The planning margin required to ensure reliability.
Solar-weighted heat rate	Avoided Fuel Costs	This is described in the described in the Avoided Fuel Costs section.
Start Year for VOS applicability	Multiple	This is the first year in which the VOS would apply and the first year for which avoided costs are calculated.
Transmission capital cost escalation	Avoided Transmission Capacity Cost	Used to adjust costs for future capital investments.
Transmission life	Avoided Transmission Capacity Cost	The assumed service life of new transmission assets.
Treasury Yields	Escalation and Discount Rates	Yields for U.S. Treasuries, used as the basis of the risk-free discount rate calculation.[22]
Years until new transmission capacity is needed	Avoided Transmission Capacity Cost	This is used to test whether avoided costs for a given analysis year should be calculated and included.

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