Maine Distributed Solar Valuation Study

Volume I: Methodology

Introduction

Methodology Overview

Figure 2 shows the calculations for the value of distributed solar in Maine, denominated in dollars per kWh. Each of the individual benefit/cost components and numerical calculations are described in this volume. Gross Value is the value of a centrally located, dispatchable resource. The Load Match Factor is a factor required for capacity-related components used to take into account the effective capacity of solar as a non-dispatchable resource. The Loss Savings Factor incorporates the added benefit associated with avoided losses from distributed resources as compared to centrally located resources. Finally, the Distributed PV Value represents the benefit or cost of a distributed, non-dispatchable resource, and these are summed to give the total value.

Figure 2. Overview of value calculation

		Gross Value A ($/kWh)	×	Load Match Factor B (%)	×	Loss Savings Factor (1+C) (%)	=	Distributed PV Value D ($/kWh)
Energy Supply	Avoided Energy Cost	C1				LSF-Energy		V1
	Avoided Gen. Capacity Cost	C2		ELCC		LSF-ELCC		V2
	Avoided Res. Gen. Capacity Cost	C3		ELCC		LSF-ELCC		V3
	Avoided NG Pipeline Cost	C4				LSF-Energy		V4
	(Solar Integration Cost)	(C5)				LSF-Energy		(V5)
Transmission Delivery Service	Avoided Trans. Capacity Cost	C6		ELCC		LSF-ELCC		V6
Distribution Delivery Service	Avoided Dist. Capacity Cost	C7		PLR		LSF-Dist		V7
	Voltage Regulation	C8						V8
Environmental	Net Social Cost of Carbon	C9				LSF-Energy		V9
	Net Social Cost of SO_2	C10				LSF-Energy		V10
	Net Social Cost of NO_x	C11				LSF-Energy		V11
Other	Market Price Response	C12				LSF-Energy		V12
	Avoided Fuel Price Uncertainty	C13				LSF-Energy		V13
								Total

Competitive Market Structure in Maine

Note that Figure 2 does not attempt to illustrate the complexities of the competitive market structure in Maine. For example, avoided energy cost is based on avoided wholesale energy purchases, but this value may involve a series of transactions between the solar customer, the distribution utility, and the energy market participants.[1]

Methodology Objectives

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

- Irradiance patterns and shading at PV system geographical coordinates;
- The 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;
- Power market prices;
- Conductor sizing on local feeder; and
- Utility financial factors.

To calculate the value for each system would be highly impractical. Instead, it is useful to calculate average values for a group, such as for all systems in a common utility 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, the distribution loss model incorporates simplifications that, to the extent possible, promote understanding while yielding representative results. A reasonable simplification is to model the entire distribution system as one device, calibrated such that all annual losses in the model agree with empirical results found in utility-reported annual losses.

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

[1] See, for example, rules 65-407 Chapter 301 “Standard Offer Service,” Chapter 313 “Customer Energy Net Billing,” and Chapter 315 “Small Generator Aggregation.”

unique to each circuit). Such an analysis would result in the costs and benefits of distributed PV at the circuit level. For the present study, however, the objective is to determine more representative "typical" results that may be obtained by using a larger geographical region.

Value Components

By statute, the methodology must, at a minimum, account for

- the value of the energy,
- market price effects for energy production,
- the value of its delivery,
- the value of generation capacity,
- the value of transmission capacity,
- transmission and distribution line losses; and
- the societal value of the reduced environmental impacts of the energy.

The methodology may also utilize "known and measurable evidence of the cost or benefit of solar operation to utility ratepayers and incorporate other values into the method, including credit for systems installed at high-value locations on the electric grid, or other factors."

Table 1 presents the value components and the cost basis for each component.

Table 1. Value components included in methodology.

Value Component	Basis	Legislative Guidance
Energy Supply		
Avoided Energy Cost	Avoided wholesale market purchases	Required (energy)
Avoided Generation Capacity Cost	Avoided cost of capacity in Forward Capacity Market	Required (generation capacity)
Avoided Reserve Capacity Cost	Capital cost of generation to meet planning margins and ensure reliability	Required (generation capacity)
Avoided Natural Gas Pipeline Cost	Cost of natural gas pipeline capacity needed to serve generation plants.	Allowed (ratepayer)
Solar Integration Cost	Added cost to follow system load with variable solar	Required (generation capacity)
Transmission Delivery Service		
Avoided Transmission Capacity Cost	Capital cost of transmission	Required (transmission capacity)
Distribution Delivery Service		
Avoided Distribution Capacity Cost	Capital cost of distribution	Required (delivery)
Voltage Regulation	Capital cost of distribution voltage regulation	Required (delivery)
Environmental		
Net Social Cost of Carbon	Externality cost	Required (environmental)
Net Social Cost of SO2	Externality cost	Required (environmental)
Net Social Cost of NOx	Externality cost	Required (environmental)
Other		
Market Price Response	Ratepayer benefit of reduced market prices	Allowed (ratepayer)
Avoided Fuel Price Uncertainty	Avoided risk of future volatility in fuel prices	Allowed (ratepayer)

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 Peak Load Reduction (PLR) load-match factor (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 may be accounted for in future adjustments to the value calculation. To the extent that PV penetration increases, future value will reflect higher PV penetration levels.

Marginal Fuel

This methodology assumes that PV displaces natural gas during PV operating hours. During some hours of the year, other fuels (e.g., oil) 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 overall value.

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[2]. Note that the sensitivity runs described later consider other assumptions for analysis period. The methodology includes PV degradation effects as described later.

Maine's Electric Utility Territories

There are twelve transmission and distribution (T&D) utilities in Maine: two investor-owned utilities (IOUs) and ten consumer-owned utilities (COUs). The IOUs—Central Maine Power Company (CMP) and Emera Maine (EME)—serve about 95% of the total State load. As summarized in the Commission's Annual Report, "there are approximately 225 Maine-licensed CEPs, who collectively currently supply about just over 50% of Maine's retail electricity usage. The remaining usage is supplied by the suppliers selected to provide "default" service, i.e. standard offer service.[3]

This study will develop estimates for the two IOUs serving 95% of total state load using the methodology described in this document. CMP and one of the two divisions of EME, the Bangor

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[2] National Renewable Energy Laboratory, NREL: Solar Resource Analysis and High-Penetration PV Potential (April 2010). http://www.nrel.gov/docs/fy10osti/47956.pdf

[3] State of Maine Public Utilities Commission 2013 Annual Report (February 2014) http://www.maine.gov/mpuc/about/annual_report/documents/attach.pdf

Hydro Division (BHE Division),[4] are located within the region whose transmission service and electricity markets are managed by ISO New England (ISO-NE)[5]. The other division of EME, the MPS Division[6], is electrically isolated from ISO-NE, instead connected directly to the New Brunswick system, and its transmission facilities and electric markets are managed by the Northern Maine Independent System Administrator (NMISA).[7] The markets operated by ISO-NE are robust and provide significant information which may be used directly or indirectly as data sources for this study. NMISA is a smaller, less sophisticated system for which there is less ample market data. In some instances, it is necessary to utilize ISO-NE values as proxies for data in the MPS territory if directly applicable data are unavailable.

High Value Locations

The methodology could be implemented at various load aggregation regions. For example, within a distribution utility, the same methodology could be used to calculate value for different distribution planning areas. Such an analysis may result in differing overall values because of differing input data. For example, in some locations, local transmission considerations may favor distributed solar more than others.[8]

It is important to note that input data must be developed for each region being analyzed. For example, each region would require its own load data, irradiance and temperature data, infrastructure cost data, and so on.

The analysis performed in this project is at the distribution utility level, resulting in a single set of costs and benefits (a single total value) for each scenario considered.

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[4] The Bangor Hydro Division and Maine Public Service Division of Emera Maine will be treated separately as the two districts are not electrically connected.

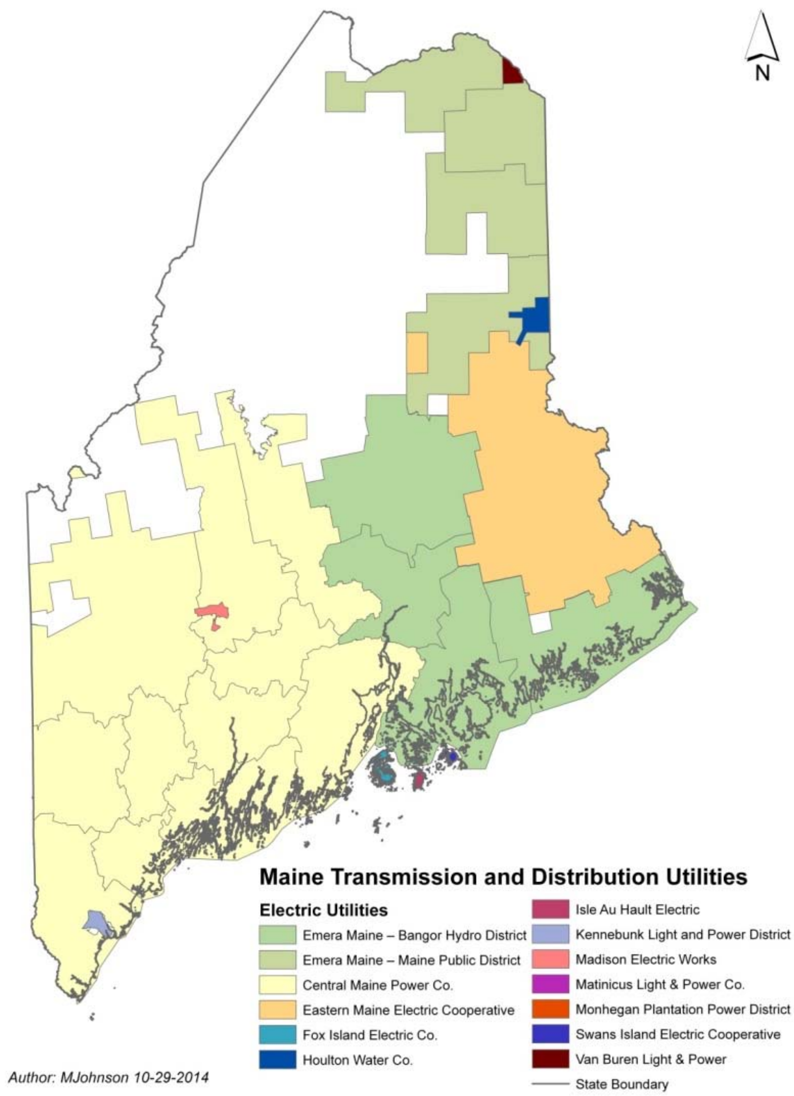
[5] http://www.iso-ne.com/main.html

[6] Owned by Emera Maine, and also referred to as Emera Maine - Maine Public District (EME-MPD).

[7] http://www.nmisa.com

[8] The Boothbay Non-Transmission Alternative Pilot Project is an example of a higher value location. See for example "Interim Report: Boothbay Sub-Region Smart Grid Reliability Project," GridSolar LLC, Docket No. 20110138, March 4, 2014.

Figure 3. Maine's T&D Utilities[9]



[9] Source: Maine Public Utilities Commission

Methodology: Technical Analysis

Load Analysis Period

The valuation 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.

PV Energy Production

PV System Rating Convention

The methodology uses a rating convention for PV capacity based on alternating current (AC) delivered energy (not direct current (DC)), taking into account losses internal to the PV system. All PV capacity under this study is calculated by multiplying the DC rating by a Standard Test Conditions (STC) to PVUSA Test Conditions (PTC) derate factor of 90%, by an inverter loss factor of 95%, and by an “other losses” factor of 90%. In other words, the AC rating is assumed to be 0.90 x 0.95 x 0.90 = 0.77, or 77% of the DC rating at standard test conditions.

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 (see Analysis Approach section for descriptions of other fleet definition profiles that will be included for sensitivity).

The 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.

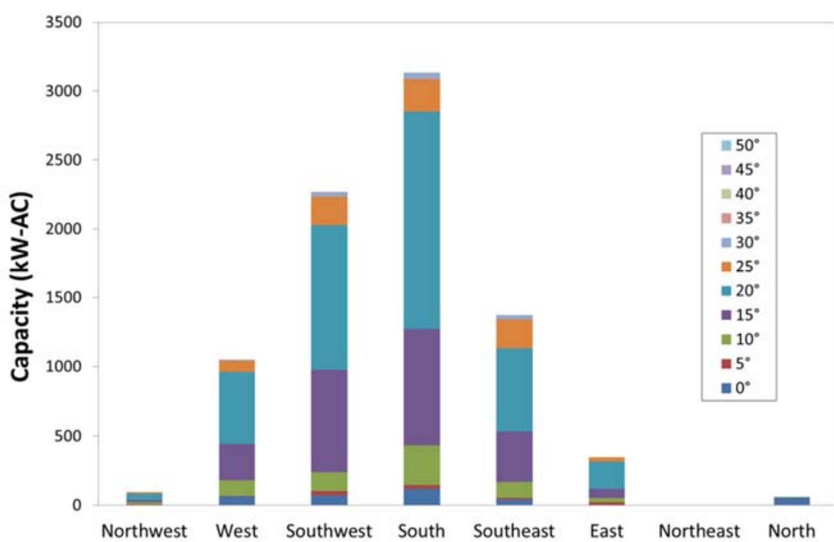
Sets of individual PV resources at the centroid of each zip code in the State are simulated over the Load Analysis Period. For each zip code, individual systems are defined, each having a distinct orientation and a capacity weighted in proportion to the expected capacity for the given orientation. The principle is illustrated in Figure 4 where a range of tilt angles and azimuth angles are assumed, but the distribution is skewed somewhat to the optimal energy (e.g., south-facing with 20 degree tilt angle). The actual weighting factors will be calculated from an analysis of all available PowerClerk® solar distributed generation (DG) system attributes from programs in New York, Massachusetts, and Connecticut.[10]

Capacity will also be weighted by zip code population. For example, the City of Augusta has a population of 19,000, while the City of Portland has a population of 66,000, or 3.5 times the population of Augusta. Therefore, the assumed PV capacity of Portland will be assumed to be 3.5 times the capacity of Augusta, and weather patterns in Portland are consequently more important than those in Augusta. Populations for each zip code will be used to weight the PV capacity assumed for each zip code.

There are 384 zip codes in Maine, and approximately 15 distinct configurations will be included at each location. Thus, there will be approximately 384 x 15 = 5,760 systems simulated for each hour of the Load Analysis Period.

Simulations are performed using CPR's FleetView™ software, incorporating satellite-derived irradiance data (SolarAnywhere®). Each system will be 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 will be taken. For each hour, the weather data will be used, array-sun angles and plane-of-array irradiance will be calculated, and PV system output will be modeled with temperature and wind speed corrections.

Figure 4. Illustration of capacity weighting by azimuth (x axis) and tilt angle (legend).



[10] PowerClerk® is CPR's incentive program and interconnection management tool used by utilities and energy agencies.

All systems will be simulated individually, and the results will be aggregated. Finally, the energy for each hour will be divided by the fleet aggregate AC rating. The units of the PV Fleet Production time series are 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.

Annual Avoided Energy

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

$$AnnualAvoidedEnergy\ (kWh) = \frac{\sum Hourly\ PV\ Fleet\ Production_h}{Number\ of\ Years} \qquad (1)$$

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 calculated:

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

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 avoided generation capacity costs, avoided reserve capacity costs, and avoided transmission capacity costs.

In developing the method for calculating ELCC, the current ISO-NE rule for Seasonal Claimed Capability for intermittent assets[11] was considered, namely, the median net real power output during Intermittent Reliability Hours:

- Hours ending 14:00 thru 18:00 – Summer (June thru September)
- Hours ending 18:00 and 19:00 – Winter (October thru May)

As PV penetration increases over the long term, however, the hourly load profiles would be expected to change to reflect lower net demand during daylight hours. With high penetration, this would shift the peak to non-daylight hours. In this case, the selection of Intermittent Reliability Hours would be expected to change to measure production on intermittent resources during the new peak hour.

In order to handle this eventuality in the high penetration scenario of this analysis, an equivalent metric is set forth here. For purposes of this study, ELCC is defined as the median of the PV Fleet Production Profile found in the peak 100 hours in the ISO-NE control area. Additionally, the ELCC must be calculated for the two loss cases (with and without T&D losses, as described in the Loss Analysis subsection). This same method will be used for all penetration scenarios, but the specific hours would be adjusted according to hourly net load.

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.

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[11] http://iso-ne.com/static-assets/documents/committees/comm_wkgrps/othr/vrwg/mtrls/a4_commercialization_and_audit.pdf

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 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 2. 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 100 peak hours in the ISO-NE control area.
PLR	Avoided distribution losses (not transmission) at peak.

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:

$$\begin{aligned} &Annual\ Avoided\ Energy_{WithLosses} \\ &\qquad = Annual\ Avoided\ Energy_{WithoutLosses}\left(1 + Loss\ Savings_{Energy}\right) \end{aligned} \tag{2}$$

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

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

Similarly, the PLR Loss Savings Factor is defined as:

$$Loss\ Savings_{PLR} = \frac{PLR_{WithLosses}}{PLR_{WithoutLosses}} - 1 \tag{4}$$

And the ELCC Loss Savings Factor is defined as:

$$Loss\ Savings_{ELCC} = \frac{ELCC_{WithLosses}}{ELCC_{WithoutLosses}} - 1 \tag{5}$$

Methodology: Economic Analysis

The following subsections provide a methodology for performing the economic calculations to derive gross values in $/kWh for each of the value 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 value result 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, 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

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

DiscountRate is the utility Weighted Average Cost of Capital.

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

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

RiskFreeDiscountRate is based on the yields of current Treasury securities[12] 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.

Finally, an environmental discount factor is given by:

$$EnvironmentalDiscountFactor_i = \frac{1}{(1 + EnvironmentalDiscountRate)^i} \tag{8}$$

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

[12] See http://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?data=yield
[13] http://www.epa.gov/oms/climate/regulations/scc-tsd.pdf

nominal discount rate, this 3% *real* discount rate is converted into its equivalent nominal discount rate as follows:[14]

$$NominalDiscountRate = (1 + RealDiscountRate) \times (1 + GeneralEscalationRate) - 1 \tag{9}$$

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:

$$PVProduction_i = PVProduction_0 \times (1 - \mathrm{PVDegradationRate})^i \tag{10}$$

where PVDegradationRate is the annual rate of PV degradation (see assumptions below). $PVProduction_0$ 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:

$$PVCapacity_i = (1 - \mathrm{PVDegradationRate})^i \tag{11}$$

Avoided Energy Cost

Avoided energy costs are based on ISO-NE hourly real time locational marginal prices for the Maine load zone. The first year avoided cost is calculated as follows:

$$\mathrm{AvoidedEnergyCost}_0 = \sum LMP_h \times HourlyPVFleetProduction_h \tag{12}$$

The first year Avoided Energy Cost will be calculated using 2013 Locational Marginal Price (LMP) data.

For future years, the first year cost will be escalated using a combination of NYMEX natural gas futures (first 12 years) and United States Energy Information Agency (EIA) forecast of natural gas prices for electric power between 2014 and 2038.[15]

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[14] http://en.wikipedia.org/wiki/Nominal_interest_rate
[15] http://www.eia.gov/oiaf/aeo/tablebrowser/#release=AEO2014&subject=16-AEO2014&table=3-AEO2014&region=1-1&cases=ref2014-d102413a

Avoided Generation Capacity Cost

The avoided generation capacity cost is based on the expected cost of generation capacity by zone in the ISO-NE Forward Capacity Market (FCM). Because of the recent adoption by ISO-NE (and approval by FERC) of a major revision to the FCM market structure (downward sloping demand curve, zonal price differentiation), historical FCM data is not a good indicator of future FCM prices. Clearing prices for forward capacity auctions (FCAs) 5 through 8, which span the present through mid-2018, will be used for those years. Thereafter, the FCM prices will be based on a simulated forecast recently completed by ISO-NE's consultant using data published in the 2014 IRP for Connecticut.[16] These prices will be annualized and adjusted for inflation. Prices beyond ten years will be escalated at the general escalation rate.

For the MPS territory, which lies outside the ISO-NE, the ISO-NE FCM prices and methodology as described above will be used as a proxy for capacity value.

The methodology should be modified as necessary in the future to address future ISO-NE rule changes or procedural changes affecting capacity markets.

Avoided Reserve Capacity Cost

Distributed PV energy is delivered to the distribution system, not transmission. Therefore, as load is reduced the reserve requirement is reduced, similar to energy efficiency.

The methodology is identical to the generation capacity cost calculation, except utility costs are multiplied by the applicable reserve capacity margin for ISO-NE and NMISA, as applicable for CMP and EME-BHD, and EME-MPD, respectively. Net ICR (not ICR) will be used in the calculation.

Avoided Natural Gas Pipeline Cost

An additional source of potentially avoided energy cost not reflected in market energy prices may be found in the current New England natural gas pipeline shortage. At present, as a general matter, most natural gas plants do not pay for firm pipeline capacity. To alleviate pipeline constraints into New England that have caused recent winter electricity prices to balloon - a situation expected to continue without investment in alleviating such pipeline constraints – the governors of Maine and other New England states have collaborated on the New England Governors Regional Infrastructure Initiative.

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[16] See p. 52, Figure 18, in 2014 Integrated Resource Plan for Connecticut, Draft for Public Comment, December 11, 2014, available at: http://www.dpuc.state.ct.us/DEEPEnergy.nsf/c6c6d525f7cdd1168525797d0047c5bf/132be6748b06f72e85257dab005fb98e/$FILE/CTIRP%202014%20Main%20Report%20-%20DRAFT%20-%20Final.pdf.

While this initiative is currently still a proposal, if adopted, it calls for electric utilities to invest in pipeline capacity and to recover cost through electricity rates charged to load via the ISO-New England tariff. Likewise, Maine is conducting a docket to consider a similar pipeline procurement, through which the PUC might seek proposals and if attractive, order electric and/or gas utilities to enter contracts.[17] Such an approach would layer onto electricity rates an additional cost potentially avoidable by solar PV electricity generation that is not embedded in market electric energy (LMP prices). Such gas pipeline costs, if funded through ISO tariff charges outside of energy market prices, would be incremental to the extent that the natural gas market price projections underlying energy market price projections presume the existence of this new pipeline capacity serving to lower natural gas commodity prices.

However, since the inclusion of gas pipeline costs in electricity prices is an uncertainty, this component is not included in the analysis. Instead, it is left as a placeholder to be applied, as appropriate, in future studies. For additional considerations about methodology, see the Appendix.

Solar Integration Cost

Solar Integration Cost covers the additional costs of operating reserves necessary to handle increases and decreases in fleet power output corresponding to solar variability. The modeling of variability and the calculation of reserve requirements is a complex task that is beyond the present project scope, so we look to other available studies for guidance. The most complete study of variable generation for New England is the New England Wind Integration Study (NEWIS).[18] This study assessed the operational effects of large-scale wind integration in New England. As distributed solar is expected to have lower variability than wind because of its more distributed nature, the use of NEWIS results may be considered an upper bound on solar integration costs.

The analysis is based on the “Partial Queue Build Out” scenario of 1,140 MW of wind, providing approximately 2.5% of forecasted annual energy demand. This compares with the approximately 10 MW of solar installed today, or over 100 times the current capacity of distributed solar. So, the study is highly conservative for our purposes both on the basis of geographical dispersion and penetration level.

The study included estimates of the following reserve requirements, and compared this to the study scenario with no wind (load only):

- 10-Minute Spinning Reserve (TMSR)
- Thirty Minute Operating Reserve (TMOR)
- Ten-Minute Non-Spinning Reserve (TMNSR)

[17] See ME PUC Docket 014-00071, “Investigation into the Parameters for Exercising Authority Pursuant to the Maine Energy Cost Reduction Act.”
[18] Available at http://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/prtcpnts_comm/pac/reports/2010/newis_report.pdf

The current methodology is based on the sum of these reserve requirements (Total Operating Reserve, TOR). The incremental TOR (study scenario less load only scenario) will be divided by the incremental wind capacity (1,140 MW) to give the incremental TOR as a percentage of renewable capacity. This value will be applied to the unit rating of the Marginal PV Resource and multiplied by the installed cost of a simple cycle aeroderivative gas turbine. An adjustment will be added to account for decreased efficiency of the units to address intermittent PV output.

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.

In an unconstrained environment, the expectation is that distributed generation can help avoid or defer transmission investment otherwise necessary to bring electricity generation from power plants connected to the transmission system at some point distant from load. The challenge is finding the cost of future transmission that is avoidable or deferrable through the use of DG. As a proxy for this price, transmission tariffs used to recover historical costs may be used.

In ISO-New England, network transmission service to load is provided under the ISO-NE Open Access Transmission Tariff (OATT)[19] as a per-KW demand charge that is a function of monthly system peaks. The charges for the transmission system is divided into charges recovering the cost of Pool Transmission Facilities (PTF) providing Regional Network Service (RNS) plus the cost of local transmission facilities not recovered under the RNS rate.

For this study, the savings that results by the reduction of distributed PV on the RNS portion of the cost is quantified. Savings on local transmission facilities may potentially be found for distributed PV from experience implementing "non-transmission alternatives." [20] Such potential savings are not included in the present study due to the site-specific nature of the reliability issues. However, the avoided local transmission costs observed in the Boothbay Pilot Project are included as an out of present study illustration of the added value of distributed solar in this region.

Avoided RNS costs are estimated by determining the savings to the distribution utility that would result from a reduction of monthly peak demands and the resulting reduction in network load allocation.

Using the PV Fleet Production Profile and the hourly loads of the ISO-NE Maine load zone, the average monthly reduction in network load is calculated for the Marginal PV Resource. For example, the

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[19] http://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_2/oatt/sect_ii.pdf

[20] See for example "Interim Report: Boothbay Sub-Region Smart Grid Reliability Project," GridSolar LLC, Docket No. 20110138, March 4, 2014.

reduction in January network load for a given year will be calculated by subtracting the hourly load by the PV Fleet Production for that hour, repeating for every hour of the month. The peak load for the month without PV is compared to the peak load with PV, and the difference, if any, is considered the reduction in network load for that month. This will be done for all January months in the Load Analysis Period, and the average over all years will be taken as the January network load reduction. The same procedure is used for the remaining months, and the results averaged using the same calculation as found in the ISO-NE Schedule 9 RNS rates.[21] The results are expressed in kW of average annual network load reduction per kW-AC of rated PV capacity. This result is assumed to be the same for the utility regions in the analysis in the ISO-NE control area. No avoided regional transmission capacity cost will be calculated for Emera Maine – Maine Public District, as it is not located in the ISO-NE region and therefore does not pay for regional network service.

The savings to the distribution utility are calculated based on the reduced load. However, an adjustment is first made to re-calculate the current RNS rate (currently $89.79639 per kW-yr) to account for the load reduction. The new rate, when applied to each local network taking into account the reduced load at the utility being evaluated, will result in the same total revenue requirement as in Schedule 9.

The re-calculated rate is multiplied by the network load reduction to give the first-year savings. This savings will be escalated at the general escalation rate over each year of the study and levelized.

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 can potentially defer or avoid the need to make these investments, provided that PV production is coincident with the local demand.

However, forecasted peak loads in Maine are generally flat, so capacity-related distribution investments are not anticipated. Therefore, this potential benefit is not included in the study, and is left as a placeholder for future studies as applicable.

One method that may be used to calculate avoided distribution capacity costs in future studies is included in the Appendix. Another approach would be to approximate costs in Maine by using values from other studies.[22]

[21] http://www.iso-ne.com/stlmnts/iso_rto_tariff/supp_docs/2014/pto_ac_info_filing_061214.pdf

[22] See for example, *Net Metering in Mississippi: Costs, Benefits, and Policy Considerations*, prepared for the Public Service Commission of Mississippi, September 19, 2014, at pp 28-29 and Figure 12.

Voltage Regulation

Distribution utilities have the responsibility to deliver electricity to customers within specified voltage windows as required by State rules.[23] When PV or other distributed generation resources are introduced onto the grid, this can affect line voltages depending upon generator rating, available solar resource, load, line conditions, and other factors. Furthermore, at the distribution level (in contrast to transmission) PV systems are more geographically concentrated. Depending upon concentration and weather variability, PV could cause fluctuations in voltage that would require additional regulation.

In some cases, these effects will require that utilities make modifications to the distribution system (e.g., adding voltage regulation or transformer capacity) to address the technical concerns. For purposes of this study, it is assumed that such costs are born by the solar generator as required by ISO-NE interconnection procedures and Chapter 324 of the Commission's rules. Consequently, no cost is assumed related to interconnection costs.

Advanced Inverters

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

Based on these considerations, it is reasonable to expect that at some point in the future, distributed PV may offer additional benefits, and Voltage Regulation 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 are not included.

Estimates of avoided environmental costs will be 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 and societal costs to the avoided emissions.

[23] See, for example, rule 65-407 Chapter 32 "Electric Utilities Service Standards."

Calculating Avoided Emissions

Avoided emissions are calculated using the U.S. Environmental Protection Agency's (EPA) "AVoided Emissions and geneRation Tool" (AVERT)[24] which calculates state-specific hourly avoided emissions of carbon dioxide (CO_2), nitrous oxides (NO_x), and sulfur dioxide (SO_2). The tool will use the Northeast data file to provide region-specific results.

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.

Net Social Cost of Carbon

The enabling statute in Maine calls for "the societal value of the reduced environmental impacts of the energy." To accomplish this objective, the value comprising federal social cost of CO_2 is included in this methodology. However, avoided carbon costs are already partially embedded in the energy value due to provider compliance with allowable carbon caps. Therefore, the approach will be to determine the "net" social cost of carbon by first calculating the total Social Cost of Carbon (SCC), then subtracting out the embedded carbon allowances costs that are already included in the energy value.

Embedded carbon costs are represented by Regional Greenhouse Gas Initiative (RGGI) forecasted market prices for carbon allowances. However, the EPA Clean Power Plan Section 111(d) of the Clean Air Act is expected to change future RGGI allowance prices from current forecasts. RGGI is a likely mechanism for Maine's compliance with the Clean Power Plan, and the use of RGGI for compliance may require a tightening of the emission cap that would result in higher allowance prices.

To address this concern and other dynamics of the market, the Synapse CO_2 Price Report[25] is used as the best available price forecast for carbon prices. Annual avoided emissions calculated from AVERT will be multiplied by the Low Case values for each year, adjusted for PV degradation.

The total avoided SCC for each year is calculated as follows. The SCC values for each year through 2050 are published in 2007 dollars per metric ton.[26] For example, the SCC for 2020 (3.0% discount rate scenario, 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.

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[24] http://epa.gov/avert/

[25] P. Lucklow, e.t., "CO_2 Price Report, Spring 2014," Synapse Energy Economics, Inc., available at http://www.synapse-energy.com. See Table 4.

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

For each study year, the avoided allowance costs are subtracted from the SCC value to get the annual net value. These values will then be levelized using the environmental discount rate.

Net Social Cost of SO_2

The approach for SO_2 is similar to that of CO_2 in that the cost of compliance, internalized in the New England energy prices, is subtracted from the social cost, resulting in the “net” social cost of SO_2.

Internalized compliance costs are calculated by applying the latest EPA allowance clearing price[27] under the Acid Rain Program to the AVERT analysis results, adjusting for inflation and PV degradation, and levelizing using the utility discount rate.

Social costs are taken from the EPA Regulatory Impact Analysis[28] estimated health co-benefit values for its recently proposed 111(d) Clean Power Plan for 2020. For example, the 2020 SO_2 costs for the East Region at the 3% discount rate are $65,000 per ton (midpoint of $40,000 and $90,000). For any given year of PV production (including degradation), this cost (adjusted for inflation) would be applied to the avoided emissions as calculated in AVERT, and discounted at the 3% rate. The net present value (NPV) would be similarly calculated for each year, summed, and levelized using the same 3% rate.

The net social cost of SO_2 would then be the levelized social cost, less the levelized compliance cost.

Net Social Cost of NO_x

The net social cost of NO_x is also based on the principle of social cost minus internalized compliance cost. However, neither Cross-State Air Pollution Rule (CSAPR)[29] nor the Clean Air Interstate Rule (CAIR) regulating NO_X is applicable in New England. Consequently the compliance cost is assumed to be zero.

The social cost is based on the 2020 NO_x costs for the East Region at the 3% discount rate, calculated using the same EPA social costs and in the manner as described above for SO_x.

Market Price Response

In markets that are structured where the last unit of generation sets the price for all generation, clearing prices for energy and capacity tend to be correlated with load demand. An example of energy clearing price-load relationship is shown in Figure 5 for a northeastern utility.

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

[28] See p. 4-26, Table 4-7, of the Regulator Impact Analysis at http://www2.epa.gov/sites/production/files/2014-06/documents/20140602ria-clean-power-plan.pdf.

[29] For more information, see http://www.epa.gov/crossstaterule/

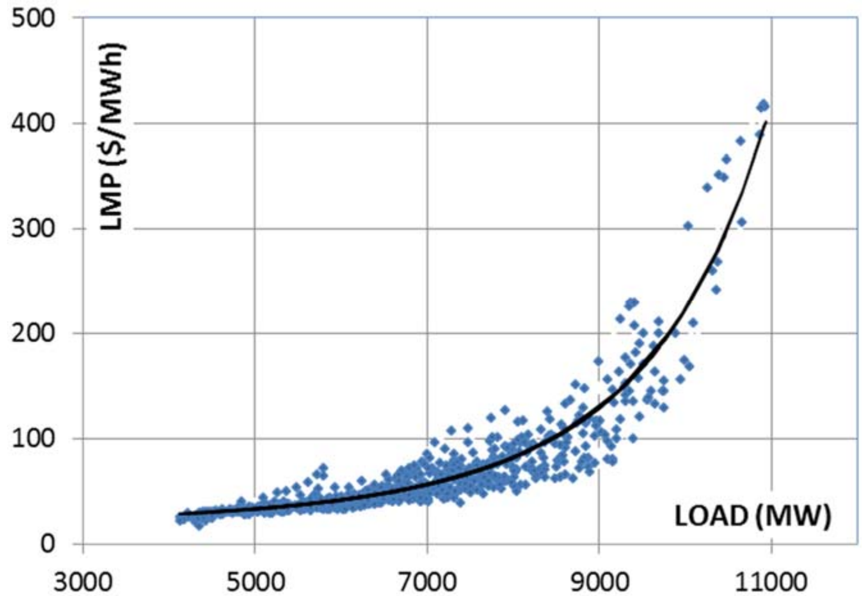

Figure 5. LMP vs. load for a large northeastern utility.

Because dispersed PV is a must-run, often user-sited resource, its impact vis-à-vis other generating resources amounts to reducing energy and capacity requirements, and per the above relationship, to reduce the market clearing price.

Two cost responses occur when distributed PV generation is deployed.

- First, there is the *direct savings* that occurs due to a reduction in load and required capacity. These are the PV energy value and PV capacity value which are explicitly calculated as transmission energy and capacity value as explained above and are not a market response effects.
- Second, there is the indirect *market price response effect*. Distributed PV generation reduces market demand and this reduction results in lower prices to all those purchasing energy and capacity from the market.

Several approaches have been proposed to quantify market response, including a first-principle methodology developed by Clean Power Research and applied in a solar value study for the Mid-Atlantic and Pennsylvania regions.[30]

For this project, we apply the results of the *Demand Reduction Induced Price Effects* (DRIPE) methodology described in the *2013 Avoided Energy Supply Costs in New England (AESC)* study. This study constitutes a reviewed, defendable precedent for the region and covers each New England state individually, including the State of Maine.

[30] Perez, R., Norris, B., Hoff, T., *The Value of Distributed Solar Electric Generation to New Jersey and Pennsylvania*, November 2012, prepared for Mid-Atlantic Solar Energy Industry Association and the Pennsylvania Solar Energy Industries Association, found at: http://mseia.net/site/wp-content/uploads/2012/05/MSEIA-Final-Benefits-of-Solar-Report-2012-11-01.pdf .

The study quantifies both energy and capacity DRIPE. Both effects are derived from an empirical linear fit of the relationship between clearing energy and capacity market prices and load demand. In addition the DRIPE methodology accounts for *market response decay* over time and for *inertial lag* before market response translate into savings.

> Market response decay: this reflects the likelihood that the market adjusts to the reduction in prices over time (e.g., via induced increased load, and/or generating units retirement and/or participation in other markets) so that market prices eventually return to the level they would have reached without DRIPE.
>
> *Inertial lag:* Market capacity prices are not affected by demand reduction in the years for which capacity prices have already been determined by the auction floor price. Therefore capacity DRIPE does not take effect until after 3 years. Energy DRIPE impacts markets immediately; however, much of the energy purchased at market price for retail load is priced in advance. Therefore the full magnitude of the energy DRIPE only takes effect 2-3 years after PV deployment.

Application of DRIPE results to PV generation

Capacity: The DRIPE method for capacity was developed assuming that demand is displaced by efficiency – i.e. a guaranty of demand reduction. PV demand reduction is not guaranteed at full installed capacity but is limited to the resource's effective capacity as quantified by the ELCC. Therefore the results of the AESC study's capacity DRIPE value per kW/month will be reduced by the ELCC factor. Finally PV capacity DRIPE will be prorated per generated PV MWh to be consistent with the other tabulated PV values. This procedure is detailed in equation (13):

$$PV\ Capacity\ Response\ Value\ per\ Mwh = \frac{12 \times CV_{AESC} \times ELCC}{PV_{MWhperkW}} \qquad (13)$$

Where CV_{AESC} is the AESC DRIPE capacity value per kW per month and $PV_{MWhperkW}$ is the nominal MWh out per installed PV kW.

Energy: The DRIPE methodology includes four empirically derived market price-load relationships covering summer and winter seasons and on-peak and off-peak periods. The period-specific fit is done to account for the exponential character of the price/load relationships as illustrated in Fig. 4. Here, the DRIPE energy value will be determined by apportioning PV output to the four time periods, per Equation (14).

$$PV\ Energy\ Response\ Value\ per\ Mwh = \frac{PV_{SPeak} \times EV_{Speak} + PV_{Soff} \times EV_{Soff} + PV_{Wpeak} \times EV_{Wpeak} + PV_{Woff} \times EV_{Woff}}{PV_{total}} \qquad (14)$$

Where PV_{total} is the annual nominal PV output. PV_{SPeak}, PV_{Soff}, PV_{Wpeak} and PV_{Woff} respectively represent nominal PV energy output during the summer on-peak and off-peak and winter on-peak and off-peak periods. EV_{SPeak}, EV_{Soff}, EV_{Wpeak} and EV_{Woff} represent the corresponding AESC DRIPE energy values per MWh.

Finally since the AESC DRIPE energy and capacity numbers are determined to be effective as of 2014, they will be escalated one year using the present study's escalation rate so as to be effective in 2015.

The DRIPE calculations will take into account Maine's hedged positions by assuming that Power Purchase Agreements and Long-Term Contracts for annual energy purchases will be about 8.5% of annual sales in the ISO-NE portion of Maine (CMP and EME-BHD).

Underlying assumptions

The market price response calculation methodology makes two key assumptions.

- Recent historical data have been used to build the LMP and capacity vs load models. This assumes that the relationships are not evolving so rapidly as to invalidate the assumption.
- The major portion of energy clearing price transactions occurs on the day-ahead market. The present methodology assumes that day-ahead exchange-wide solar production forecasts are accurate enough to capture day-ahead value without the risk of creating large spikes on the balancing real time market. Given the state of the art in current regional solar forecasting, this assumption appears reasonable.

Avoided Fuel Price Uncertainty

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

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 a few 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 Energy Cost section.

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.

Finally, the selection of heat rate will be projected based on the declining trend of Locational Marginal Unit (LMU) heat rates as described in the ISO-NE Electric Generator Air Emissions Report.[31]

[31] 2012 ISO New England Electric Generator Air Emissions Report, found at http://www.iso-ne.com/genrtion_resrcs/reports/emission/2012_emissions_report_final_v2.pdf.

Appendix 1: Avoided Distribution Capacity Cost

The following discussion is intended to inform future evaluations of transmission costs avoided by distributed solar in the State of Maine. Distribution capacity costs are not included in the present analysis because it is assumed that peak loads are not increasing in the foreseeable future.

Avoided distribution capacity costs are determined using actual data from each of the last 10 years and peak growth rates are based on the utility's estimated future growth over the next 15 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 shown in Table 3.

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

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):

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

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

A sample economic value calculation is presented in Table 4. The distribution cost for the first year ($200 per kW in the example) is taken from the analysis of historical cost and estimated growth as described above. This cost is escalated each year.

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 value component rate is calculated such that the total discounted amount equals the discounted utility cost.

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	

CONTINUED

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

Appendix 2: Avoided Natural Gas Pipeline Costs

This appendix includes considerations for future value studies to be applied as appropriate. This component will not be included in the current study.

While solar PV production is certainly not at its peak during the winter, PV does produce energy during winter peak periods reflected in price spikes in the natural gas transportation basis from Henry Hub to New England Burner tip. Reduced energy demand due to PV production during these periods could potentially avoid or defer expenditures on pipeline expenditures.

Because pipeline gas is a daily delivery commodity (the pipeline serves effectively as storage within the day), the expected impact would be expected to correlate with average daily PV production during winter peak months with elevated pipeline basis differentials.

The calculation would be as follows:

- Only winter hours are included (summer is assumed to be negligible).
- Average winter PV production is calculated from the PV Fleet Shape for the winter hours.
- The first year cost is calculated by multiplying the average winter PV production (kWh per kW-AC) by the winter average ISO-NE marginal heat rate (Btu per kWh) and the pipeline capacity price ($ per MMBtu) and applying unit conversions.
- Future year values are escalated using general escalation, and the time series is levelized.