Maine Distributed Solar Valuation Study

Volume II: Valuation Results

Solar Valuation Results

Using the methodology described in Volume I, the benefits and costs of distributed solar were evaluated, and the results are presented and summarized here. In addition, details of the calculations are provided in the appendices, as follows:

- Appendix 1: Fleet Modeling
- Appendix 2: Fleet Modeling Results
- Appendix 3: Technical Factors
- Appendix 4: Cost Calculations
- Appendix 5: Annual VOS Calculations
- Appendix 6: Sensitivity Cases

Key assumptions for the CMP Base Case Analysis are shown in Table 5. The assumed discount rate, technical factors, and transmission average monthly peak reduction are unique to CMP—values for Emera Maine's Bangor Hydro District (BHD) and Maine Public District (MPD) use different assumptions for these values. Sensitivity cases (Appendix 6) consider a range of other assumptions for fleet makeup (e.g., fleets comprising designs for optimal capacity), PV life and degradation, and other factors.

Figure 6 presents the overall value results for the CMP Base Case in the first year. Avoided market costs—including Energy Supply, Transmission Delivery, and Distribution Delivery—are $0.09 per kWh. Additional societal benefits are $0.092 per kWh. Avoided NG Pipeline Cost, Avoided Distribution Capacity Cost, and Voltage Regulation are included as placeholders for future evaluations, but results are not included here for reasons described in the methodology.

Avoided market costs represent the benefits and costs associated with capital and operating expenses normally recovered from ratepayers, such as wholesale energy purchases and capacity. Societal benefits are those which accrue to society but are not typically included in setting rates. For example, the social cost of carbon is based on an estimate of costs that will be incurred to mitigate future impacts of carbon emissions, but those costs are not reflected in electric rates.

Table 5. CMP Base Case Assumptions

Economic Factors

Start Year for VOS applicability	2016	
Discount rate (WACC)	10.32%	per year
Discount Rate - Environmental	3.00%	per year
General escalation rate	1.80%	per year

Technical Factors

ELCC (no loss)	54.4%	% of rating
Loss Savings - Energy	6.2%	% of PV output
Loss Savings - ELCC	9.3%	% of PV output

Solar

First year annual energy	1628	kWh per kW-AC
PV degradation rate	0.5%	per year
PV life	25	years

Other

First Year Avoided Energy Cost	57.49	$ per MWh
Reserve planning margin	13.6%	%
Installed cost of reserve capacity	$16.23	$ per kW-mo
Total Operating Reserves	1.75%	% of solar cap.
First Year RNS Rate	$89.80	$ per kW-yr
Trans. Avg. Monthly Peak Reduction	0.239	kW per kW-AC
CCGT Heat Rate	7,615	BTU per kWh

Treasury Yields

1 Year	0.1%	per year
2 Year	0.5%	
3 Year	0.9%	
5 Year	1.6%	
7 Year	2.1%	
10 Year	2.5%	
20 Year	3.1%	
30 Year	3.3%	

Energy DRIPE

2016	$8.59	$ per MWh
2017	$33.31	
2018	$35.33	
2019	$36.63	
2020	$35.81	
2021	$31.01	
2022	$26.87	
2023	$19.95	
2024	$13.31	
2025	$6.79	

Displaced Emissions

SO2	1.356	lbs per MWh
NOx	0.799	lbs per MWh
CO2	0.553	tons per MWh

Figure 6. CMP Distributed Value – First Year ($ per kWh)

First Year		Distributed Value ($/kWh)
Energy Supply	Avoided Energy Cost	$0.061
	Avoided Gen. Capacity Cost	$0.015
	Avoided Res. Gen. Capacity Cost	$0.002
	Avoided NG Pipeline Cost	
	Solar Integration Cost	-$0.002
Transmission Delivery	Avoided Trans. Capacity Cost	$0.014
Distribution Delivery	Avoided Dist. Capacity Cost	
	Voltage Regulation	
Environmental	Net Social Cost of Carbon	$0.021
	Net Social Cost of SO_2	$0.051
	Net Social Cost of NO_x	$0.011
Other	Market Price Response	$0.009
	Avoided Fuel Price Uncertainty	$0.000
		$0.182

Avoided Market Costs $0.090

Societal Benefits $0.092

Long Term Value

Error! Not a valid bookmark self-reference. provides additional details in the benefit and cost calculations, including load match factors and loss savings factors, and the costs and benefits are shown as 25 year levelized values.provides additional details in the benefit and cost calculations, including load match factors and loss savings factors, and the costs and benefits are shown as 25 year levelized values.

Figure 7. CMP Distributed Value – 25 Year Levelized ($ per kWh)

25 Year Levelized		Gross Value A ($/kWh)	×	Load Match Factor B (%)	×	Loss Savings Factor (1+C) (%)	=	Distr. PV Value D ($/kWh)	
Energy Supply	Avoided Energy Cost	$0.076				6.2%		$0.081	Avoided Market Costs $0.138
	Avoided Gen. Capacity Cost	$0.068		54.4%		9.3%		$0.040	
	Avoided Res. Gen. Capacity Cost	$0.009		54.4%		9.3%		$0.005	
	Avoided NG Pipeline Cost								
	Solar Integration Cost	($0.005)				6.2%		($0.005)	
Transmission Delivery Service	Avoided Trans. Capacity Cost	$0.063		23.9%		9.3%		$0.016	
Distribution Delivery Service	Avoided Dist. Capacity Cost								
	Voltage Regulation								
Environmental	Net Social Cost of Carbon	$0.020				6.2%		$0.021	Societal Benefits $0.199
	Net Social Cost of SO_2	$0.058				6.2%		$0.062	
	Net Social Cost of NO_x	$0.012				6.2%		$0.013	
Other	Market Price Response	$0.062				6.2%		$0.066	
	Avoided Fuel Price Uncertainty	$0.035				6.2%		$0.037	
								$0.337	

Gross Values represent the value of a perfectly dispatchable, centralized resource. These are adjusted using the Load Match Factors and Loss Savings Factors shown to account for the non-dispatchability of solar and the benefit of avoiding losses in the T&D systems. The details of the Gross Value calculations are provided in Appendix 4 and Appendix 5.

The Load Match Factor associated with generation capacity (ELCC) was calculated as described in the methodology, and represents the output of solar during the top 100 load hours per year, expressed as a percentage of rated solar capacity (AC ratings, including system losses). ELCC results for other scenarios are presented in Appendix 3.

The load match factor for Avoided Transmission Capacity Cost is the 3-year average monthly reduction in peak transmission demand for CMP as required by the transmission cost methodology. Note that this is similar to PLR but is calculated differently to correspond with the allocation of RNS transmission costs.

The Distributed PV value is calculated for each benefit and cost category, and these are summed to obtain the overall value of $0.337 per kWh. This value is a 25-year levelized value, meaning the equivalent constant value that could be applied over 25 years such that the resulting net present value (NPV) would account for the full value stream.

Comparison of the Three Investor-Owned Utilities

First Year results for all three utility service territories, including Emera Maine's BHD and MPD, are shown in Figure 8. The results are seen the same for the first year results except for the avoided transmission cost component which reflects hourly load profiles. RNS rates do not apply to MPD so there is no avoided transmission cost included. Avoided energy is the same because the solar profile was assumed to be the same state-wide, and the LMPs are taken for the Maine zone. Avoided generation capacity costs are based on the same solar profiles and the same ISO-NE loads, so there are no differences in this category. There are differences in long term value due to differences in utility discount rate (not shown).

Figure 8. Base Case Results for CMP, BHD, and MPD

First Year		CMP $/kWh	BHD $/kWh	MPD $/kWh
Energy Supply	Avoided Energy Cost	0.061	0.061	0.061
	Avoided Gen. Capacity Cost	0.015	0.015	0.015
	Avoided Res. Gen. Capacity Cost	0.002	0.002	0.002
	Avoided NG Pipeline Cost			
	Solar Integration Cost	(0.002)	(0.002)	(0.002)
Transmission Delivery Service	Avoided Trans. Capacity Cost	0.014	0.017	0.000
Distribution Delivery	Avoided Dist. Capacity Cost			
	Voltage Regulation			
Environmental	Net Social Cost of Carbon	0.021	0.021	0.021
	Net Social Cost of SO_2	0.051	0.051	0.051
	Net Social Cost of NO_x	0.011	0.011	0.011
Other	Market Price Response	0.009	0.009	0.009
	Avoided Fuel Price Uncertainty	0.000	0.000	0.000
		0.182	0.184	0.168

Appendix 1: Fleet Modeling

Five hourly solar PV fleet profile data sets were prepared for the Load Analysis Period covering 2011 through 2013. These data sets provide normalized PV production data for sample fleets. The data is scalable and can be used for a variety of planning purposes, such as determining expected hourly import and export energy through the meter.

Table 6. Hourly data sets, covering 2011 through 2013

	1-Hour Resolution **SolarAnywhere Standard Res.** **10 km x 10 km x 1 hour** **2011 - 2013**
Base Case	Fleet production profile based on 9,600 systems (25 orientations at each of 384 sites)
Residential Proxy	Fleet production profile based on 6,528 systems (17 orientations at each of 384 sites)
Non-Residential Proxy	Fleet production profile based on 9,216 systems (24 orientations at each of 384 sites)
Maximum Energy Production	Fleet production profile based on 384 systems (single orientation at each of 384 sites)
Maximum Capacity	Fleet production profile based on 384 systems (single orientation at each of 384 sites)

Fleet Categorization

The requested five production profiles were obtained from PV fleets that fall into two main categories: fleets with multiple system orientations (azimuth and tilt) at each location and fleets with a single system orientation at each location. Complete information on the composition of each fleet is provided in the Fleet Creation section.

Representative Fleets

The fleets with multiple system orientations at each location were designed to be representative of the mix of PV array orientations that are actually found in real-world fleets. These fleets are referred to as representative fleets. For this study, the representative fleets are the Base Case, Residential, and Non-Residential fleets.

Single-orientation Fleets

The fleets with a single system orientation at each location were created to look at specific scenarios. Using systems located in Portland, Maine, the Maximum Energy fleet used systems with the orientation that resulted in the greatest energy production, while the Maximum Capacity fleet focused on the orientation that resulted in the greatest Effective Load Carrying Capability (ELCC).

Data Sources and Tools

In preparing these production profiles, Clean Power Research made use of data from a variety of sources to help identify the location and size of the PV systems in each fleet and to facilitate PV system modeling.

SolarAnywhere® Weather Data

SolarAnywhere standard resolution data (10 km x 10 km x 1 hour) was used as a source for solar irradiance and other weather data needed to perform PV system modeling.

PowerClerk® Incentives Program Data

PowerClerk served as a source for array orientation statistics from installed systems in the northeast United States. Those statistics were used to inform the allocation of capacity among the various design configurations at each location in the representative fleets.

ISO NE Load Data

Electric load data was obtained from the ISO New England web site[32] and used in calculating ELCC to determine the orientation for the Maximum Capacity fleet.

[32] Energy, Load, and Demand Reports, 2011 SMD Hourly Data, 2012 SMD Hourly Data, and 2013 SMD Hourly Data, http://www.iso-ne.com/isoexpress/web/reports/load-and-demand/-/tree/zone-info

ZIP Code Data

ZIP code data was obtained from zip-codes.com, who combines information from the U.S. Postal Service and the Census Bureau. This information was used in determining system locations and relative capacity.

PV Modeling Tools

PV power and energy production were modeled using simulation tools developed by Clean Power Research and based on the PVFORM power model. These sophisticated tools make use of satellite-derived irradiance, temperature and wind speed from SolarAnywhere. Calculations are performed for sun angle and atmospheric effects, system orientation and shading. The tools incorporate inverter power curve modeling and account for the effect of temperature and wind speed on performance as well as other system losses due to module mismatch and wiring.

Fleet Creation

Modeling of PV fleets is accomplished by first creating specifications for a number of systems. The power and energy output for each system is then calculated for some period of time and the results are aggregated. The specifications needed for each system include[33]:

- System location (latitude and longitude)
- Rated array output
- Array orientation (azimuth and tilt, along with information about tracking equipment, if any)
- Inverter output and efficiency rating
- Derate factors to account for PV module and system losses

For this study, each system was assigned a single fixed (non-tracking) PV array. Therefore the array DC rating is the same as the system DC rating. Also, since there's only one array orientation, array orientation is the same as the system orientation.

System Location

The latitude and longitude of the geographic center of 384 Maine ZIP code territories with a population greater than zero were used as the locations for the systems in each of the five solar PV fleets that were modeled.

[33] There are many additional aspects of system design that can be included when modeling. This is a partial list that covers the most important information.

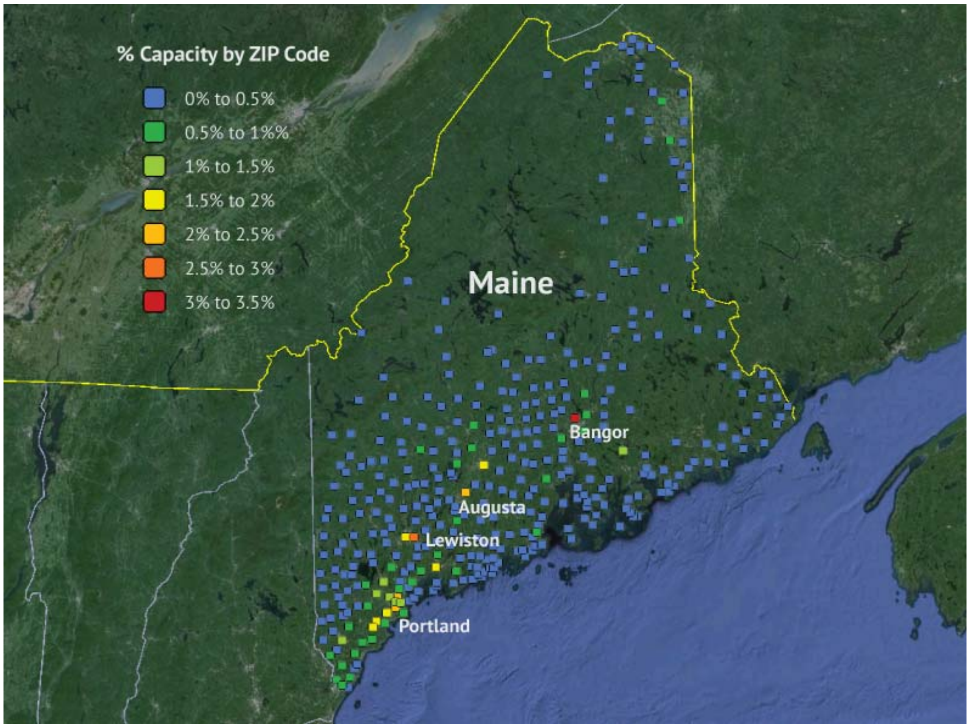
Rated Array Output

For the single-orientation fleets, the rated output for each array was based solely on a population weighting factor. For representative fleets, rated output was based on a combination of a population weighting factor and an orientation weighting factor.

Population Weighting Factors

Population estimates based on the 2010 census were used to calculate weighting factors that were used in determining each system's rated output. Systems located in areas with a larger population were assigned more electrical capacity than systems in areas with a smaller population.

Figure 9. Population weighting factors for 384 ZIP code territories



Array Orientation

As mentioned previously, the representative fleets in this study included systems with a variety of different array orientations, while all of the systems in a single-orientation fleets have the same tilt and azimuth. The following sections describe the process of identifying the orientations to be used and, in the case of representative fleets, assigning weighting factors to each orientation.

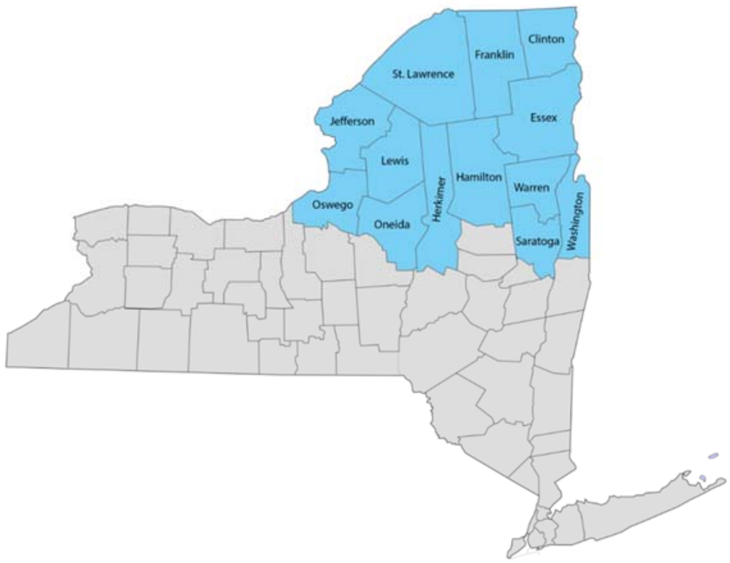
Representative fleets

Program data analysis

Behind-the-meter PV system data from PowerClerk incentive programs in New York, Connecticut, and Massachusetts was used to estimate the relative capacity of each system orientation in the Base Case, Residential, and Non-Residential fleets. System selection criteria included customer class, system size, and location. The criteria for each customer classes were defined as:

- **Base Case fleet** – Based on analysis of 33,367 systems with ratings under 500 kW-DCSTC. The total capacity of the systems analyzed was 8.8 MW-DCSTC.
- **Residential fleet** – Based on analysis of 1,284 residential systems, totaling 358 kW-DCSTC capacity, located in Upstate New York with ratings under 500 kW-DCSTC. Upstate New York was defined as the counties of St. Lawrence, Franklin, Clinton, Jefferson, Lewis, Herkimer, Hamilton, Essex, Warren, Washington, Oswego, Oneida, and Saratoga.
- **Non-Residential fleet** – Based on analysis of 2,842 non-residential systems, totaling 720 kW-DCSTC capacity, with ratings from 10 kW-DCSTC to 500 kW-DCSTC.

Figure 10. Upstate New York Counties Used in Residential Fleet Construction



Azimuth selection

Per-array capacity[34] was determined for the arrays at each azimuth relative to the total capacity. Five azimuth midpoints were selected, from which azimuth angle ranges were then derived.

Table 2 illustrates the five nominal azimuth angles that were selected: 90° (east), 135° (southeast), 180° (south), 225° (southwest), and 270° (west). Capacity for arrays with azimuths that were +/- 22.5° from these points were added to the central capacity. For example, capacity from arrays ranging from 157.5° to 202.5° was added to the 180°capacity bin.

[34] Capacity is analyzed at the array level rather than the system level in order to properly account for systems with multiple arrays.

Table 7. Selected azimuths and associated azimuth bins

Residential and Non-Residential		
Nominal Azimuth	Actual Azimuth >=	Actual Azimuth <
90	67.5	112.5
135	112.5	157.5
180	157.5	202.5
225	202.5	247.5
270	247.5	292.5

Tilt selection

A process similar to that used for azimuth selection was also used for selecting array tilts. Tilt angles and ranges used to combine capacity for each customer class were as shown below in Table 8.

Table 8. Selected tilts and associated tilt bins

Residential and Non-Residential		
Selected Tilt	Actual Tilt >=	Actual Tilt <
30	25	37
20	15	25
10	10	15
5	5	10
0	0	5

Results: Orientation weighting factors

Once the 25 azimuth and tilt combinations were defined, the percent of capacity that fell into each bin was determined. Only fixed (non-tracking) systems were examined. This yielded a list of weighting factors for each of three fleets with one weighting factor per orientation bin (the combination of azimuth, and tilt). The distribution of orientations for each of the three fleets is shown in the charts below.

Figure 11. Distribution of rated array by azimuth and tilt angle (Base Case)

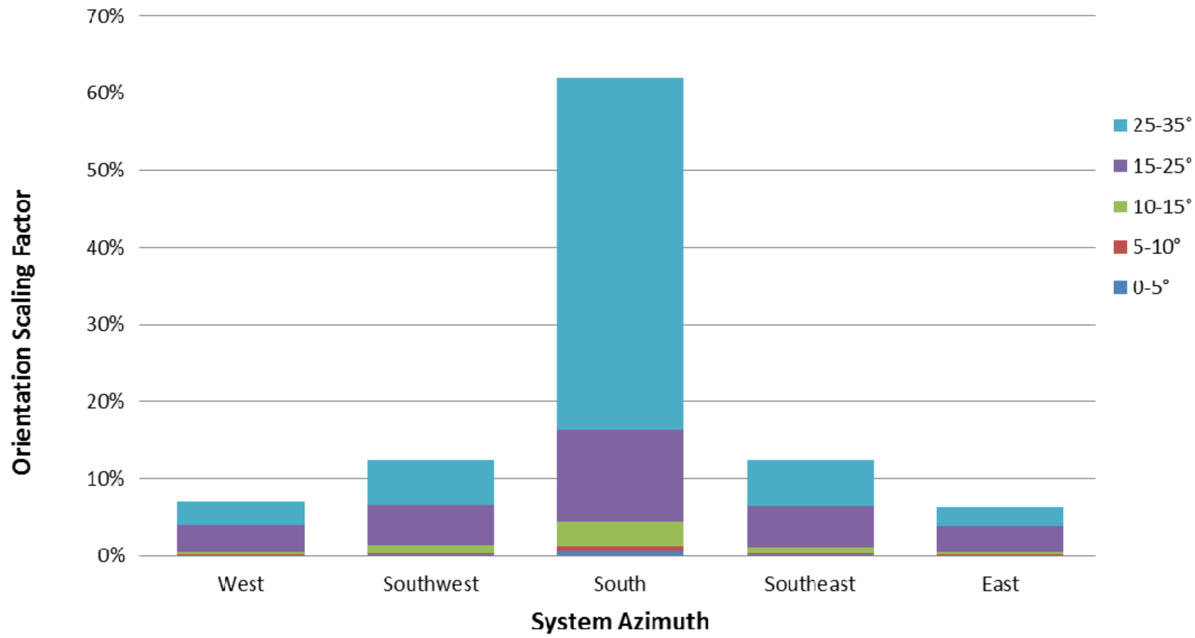


Figure 12. Distribution of rated array capacity by azimuth and tilt angle (Residential)

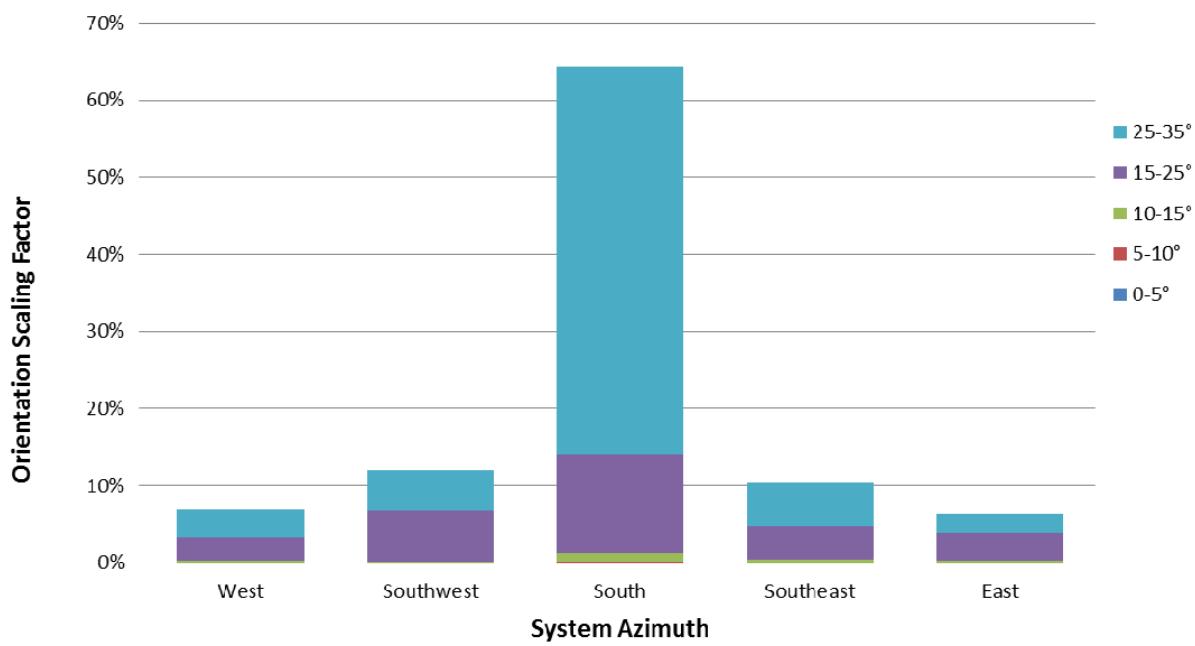
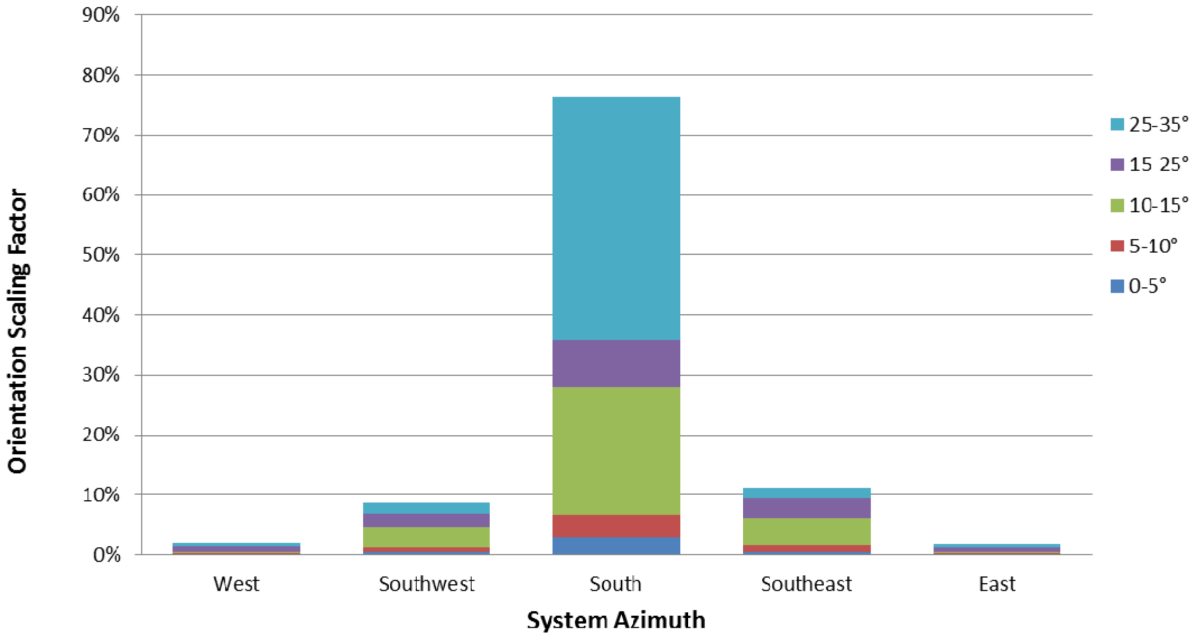


Figure 13. Distribution of rated array capacity by azimuth and tilt angle (Non-Residential)



System Capacity Determination

In each of the representative fleets, one system was created for each of the included orientations at every location. The actual AC capacity used for each system was determined by multiplying the population weighting factor for the location by the orientation weighting factor.

For example, ZIP code 04005 has a population of 22,941, which is approximately 1.867% of the total population considered. Its population weighting factor, therefore, was 0.0186673. In the systems analyzed for the Base Case fleet, the 1,813 arrays with an azimuth from 112.5° to 157.5° (the sector centered around 135°) and a tilt from 15° to 25° (centered around 20°) had a total capacity of 472.1 kW DC_{STC}, or 5.36% of the total. Therefore, the systems created at each location to represent this orientation would have an azimuth of 135°, a tilt 20° and an orientation weighting factor of 0.0536 (5.36%).

When located at ZIP code 04005, the system's capacity would be 0.01867 (population weighting) times 0.0536 (orientation weighting) or 0.00100011704 kW. To avoid rounding errors when calculating the output of such small systems, all systems capacities were scaled by a factor of 1,000,000. The actual size used, therefore, was 1,000.11704 kW AC.

Single design configuration fleets

The orientation and tilt selected for the systems in the single design fleets was obtained quite differently than for the representative fleets. The goal for the Maximum Energy fleet was to create a single system at each location whose capacity was representative of the ZIP code's population, but whose orientation and tilt produced the most energy when located in Portland, Maine. Similarly, the goal for the Maximum Capacity fleet was to create a single system at each location whose orientation and tilt had the best ELCC when located in Portland, Maine.

System variations

To determine the orientations to be used for the Maximum Energy and Maximum Capacity fleets, 42 candidate systems were modeled with seven different azimuths from 90° (east) to 270° (west) in 30° increments, and six tilts at each azimuth from 0° (horizontal) to 50° in 10° increments. All systems had a capacity of 1 kW-AC and were located in Portland, ME. The output of these 42 systems from January 1, 2011 through December 31, 2013 was analyzed to determine maximum energy and ELCC.

Maximum Energy Fleet

For the Maximum Energy fleet, a south-facing system with a 40° tilt was selected based on its 1,806 kWh per kW-AC maximum of the three-year average of the normalized annual energy from the 42 systems. These averages are shown in Table 9.

Table 9. Average Annual Energy for 42 Candidate Systems in Portland (kWh per kW-AC)

		Azimuth						
		West	**240°**	**210°**	**South**	**150°**	**120°**	**East**
Tilt	**0°**	1,487	1,487	1,487	1,487	1,487	1,487	1,487
	10°	1,476	1,554	1,610	1,630	1,609	1,552	1,475
	20°	1,442	1,587	1,693	1,731	1,692	1,585	1,441
	30°	1,392	1,591	1,736	1,790	1,735	1,590	1,393
	40°	1,332	1,568	1,741	1,806	1,740	1,568	1,332
	50°	1,259	1,517	1,705	1,779	1,705	1,518	1,261

Systems with this orientation were then created at each of the 384 locations, with their capacity based on the relative population at each location.

Max Capacity Fleet

Using ISO New England load data for 2011 through 2013, the ELCC of each of the 42 candidate systems in Portland was calculated by taking the 100 hours in each year with the highest load, then taking the median of the system output at the each of the hours corresponding to the load hours. Figure 14 illustrates this calculation for the one candidate system having an azimuth angle of 210 degrees and a tilt of 30 degrees.

In the figure, the top 100 load hours for the ISO-NE are shown for each of 2011, 2012 and 2013 along with the associated PV production for that hour. This data is in rank order by load. For example, the peak load hour for the entire Load Analysis Period of 27,333 MW occurred on July 22, 2011 during the hour ending 2:00 pm EST. This is plotted as a dark blue data point (part of the 2011 data series) in the upper left-hand corner. The second highest 2011 load is plotted adjacent to it, and so on for all 100 top hours of 2011. Next, the top 100 hours of 2012 and 2013 are plotted as overlaid data series in the same fashion, each also sorted by load.

At the peak hour ending 2:00 pm EST on July 22, 2011, the candidate PV system produced 0.83 kW per kW-AC of rated capacity. This is plotted on the chart as a dark red data point (2011) for the corresponding hour, namely, the leftmost X value on the chart, directly under its associated load. The other PV production results are plotted similarly for the remaining load hours.

Among the 300 PV production data points plotted, the median value of 0.633 kW per kW-AC is found, or 63.3% of rated capacity. For this candidate system, therefore, the ELCC is determined to be 63.3% of rated output, and this is included in the results of all 42 systems shown in Table 10 (boxed in yellow).

As can be seen in Table 10, among all the candidate systems modeled in Portland, this system (210° azimuth and 30° tilt) had the highest ELCC. To create the Maximum Capacity fleet, systems with this same orientation were created at each of the 384 locations, with their capacity scaled based on the relative population at each location.

As will be seen in Appendix 3, the maximum capacity fleet thus defined has a blended ELCC of 60.4%, slightly lower than the specific system in Portland. The blended fleet ELCC is used for the analysis.

Figure 14. Illustration of ELCC Calculation

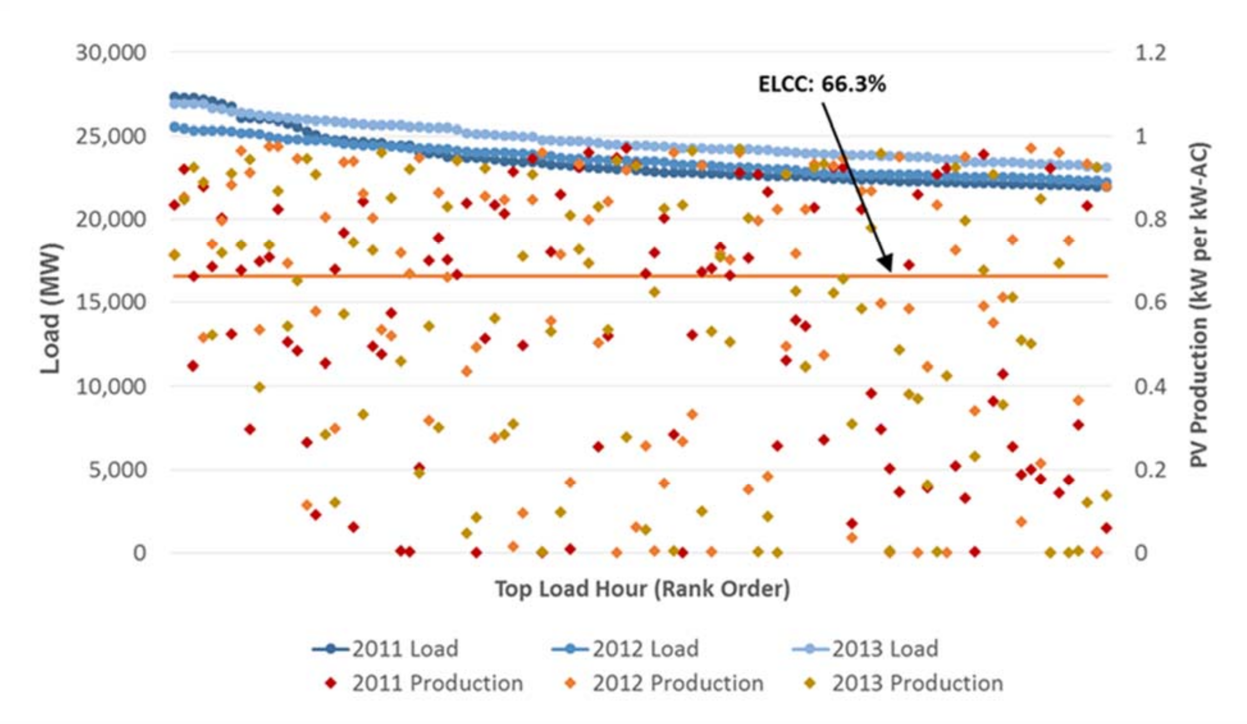


Table 10. ELCC for 42 Candidate Systems at Portland

Tilt \ Azimuth	West	240°	210°	South	150°	120°	East
0°	57.7%	57.7%	57.7%	57.7%	57.7%	57.7%	57.7%
10°	63.9%	64.2%	62.7%	59.6%	55.1%	51.4%	49.6%
20°	63.7%	64.3%	65.4%	59.6%	49.9%	43.1%	39.0%
30°	64.7%	66.1%	$\boxed{66.3\%}$	57.2%	43.3%	37.5%	34.5%
40°	63.4%	65.4%	62.3%	54.1%	41.4%	32.9%	24.7%
50°	59.8%	62.7%	57.0%	49.3%	37.4%	23.8%	14.9%

ISO NE vs ME Load analysis

Although only the ISO NE data was used in the determination of the system orientation for the Maximum Capacity fleet, for comparison the same technique was used with load data from the Maine load zone.

Table 11. ELCC Using Maine 2011-2013 Load

Tilt	Azimuth: West	240°	210°	South	150°	120°	East
0°	57.7%	57.7%	57.7%	57.7%	57.7%	57.7%	57.7%
10°	59.6%	60.6%	61.3%	59.2%	55.3%	52.8%	52.3%
20°	60.7%	62.2%	61.5%	58.9%	53.4%	49.8%	45.3%
30°	60.9%	62.2%	62.4%	56.9%	50.9%	43.0%	36.9%
40°	53.5%	62.9%	60.7%	54.3%	47.2%	35.3%	25.3%
50°	51.2%	55.4%	54.7%	50.1%	41.3%	24.5%	16.6%

Although the ELCC values were similar for both the Maine and ISO NE load data, using the Maine data would have resulted in the selection of a system with a 240° azimuth and 40° tilt. This is the same orientation that produced the maximum average annual energy over the study period.

Appendix 2 - Fleet Modeling Results

Data Summary

Depending on location, data was unavailable for systems during 16 or more hours of the study period. Fifteen of the missing periods (fourteen in some locations) occurred on a single day – May 22, 2013 and in the fleet production profile data sets the energy shown for May 22, 2013 is actually a copy of the data from May 21, 2013.

In identifying the system orientation to be used for the Maximum Energy fleet, we used the data from May 21, 2013 as a proxy for the missing data on May 22, 2013. However, adding in the small amount of additional energy produced on May 21, 2013 had no effect on the selection of system orientation for the Maximum Energy fleet, since every system had additional energy production on that day.

Table 12. Summary of Missing Data Periods

	3-year Total		2011		2012		2013	
	Missing Periods	% Missing	Missing Periods	% Missing	Missing Periods	% Missing	Missing Periods	% Missing
Minimum	16	0.06%	2	0.02%	0	0.00%	14	0.16%
Maximum	24	0.09%	2	0.02%	3	0.03%	19	0.22%

Since none of the missing hours were among the 100 in each year with the highest load, missing data had no effect on the ELCC calculations.

The AC capacity factor for each system was calculated by dividing the actual estimated production by the product of the system's AC capacity and the number of hours in the period. For example, the AC capacity factor for a 2.5 kW-AC system that produced 3,797 kWh in 2011 would be calculated as:

$$3{,}797 \text{ kWh} \div 21{,}900 \text{ kWh} = 17.3\%$$

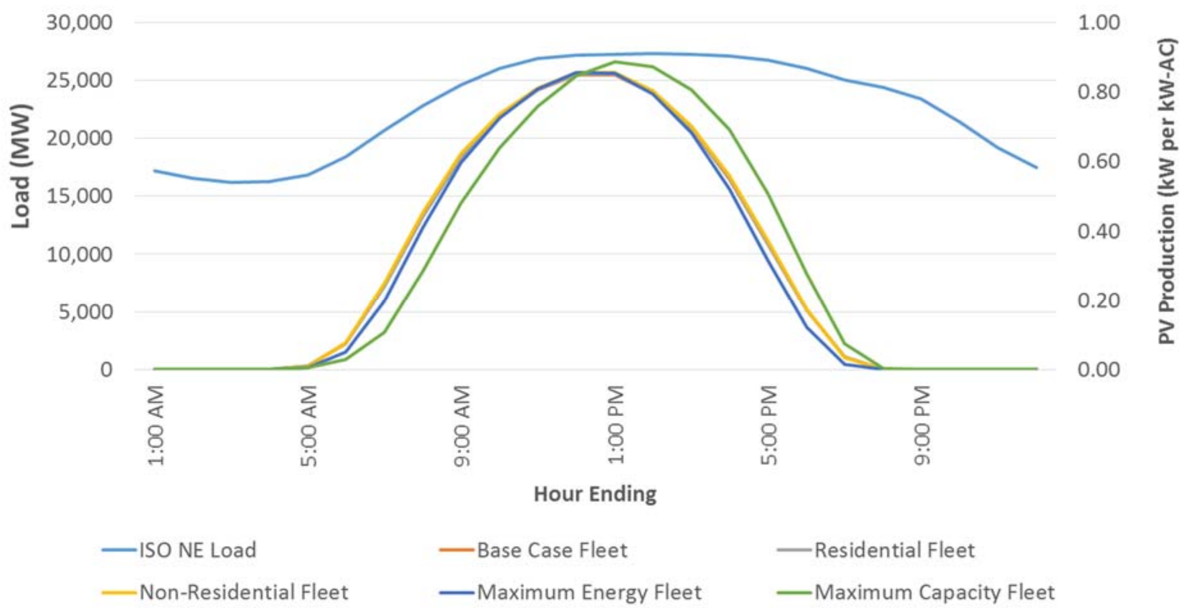
Note that 2.5 kW x 8,760 hours in 2011 = 21,900 kWh. Annual and three-year AC capacity factors were calculated and the three-year minimum, maximum, and average AC capacity factors are shown for each fleet in Table 13.

Table 13. Three-year AC Capacity Factor by Fleet[35]

	Base Case	Residential	Non-Residential	Maximum Energy	Maximum Capacity
Minimum	13.4%	13.4%	13.4%	17.4%	16.8%
Maximum	20.5%	20.5%	20.5%	20.7%	19.9%
Average	16.8%	17.0%	16.8%	19.6%	18.9%

PV Production Shapes on ISO NE Peak Load Days

Figure 15. Normalized Fleet Production vs. ISO NE Load on 2011 Peak Load Day – July 22, 2011



[35] Note that the term "capacity" as used here has a different meaning than other uses of the term elsewhere in this report. In the context of this table, capacity factor is a measure of annual energy production as described above. Note that the maximum energy fleet produces the highest annual capacity factor.

Figure 16. Normalized Fleet Production vs. ISO NE Load on 2012 Peak Load Day – July 17, 2012

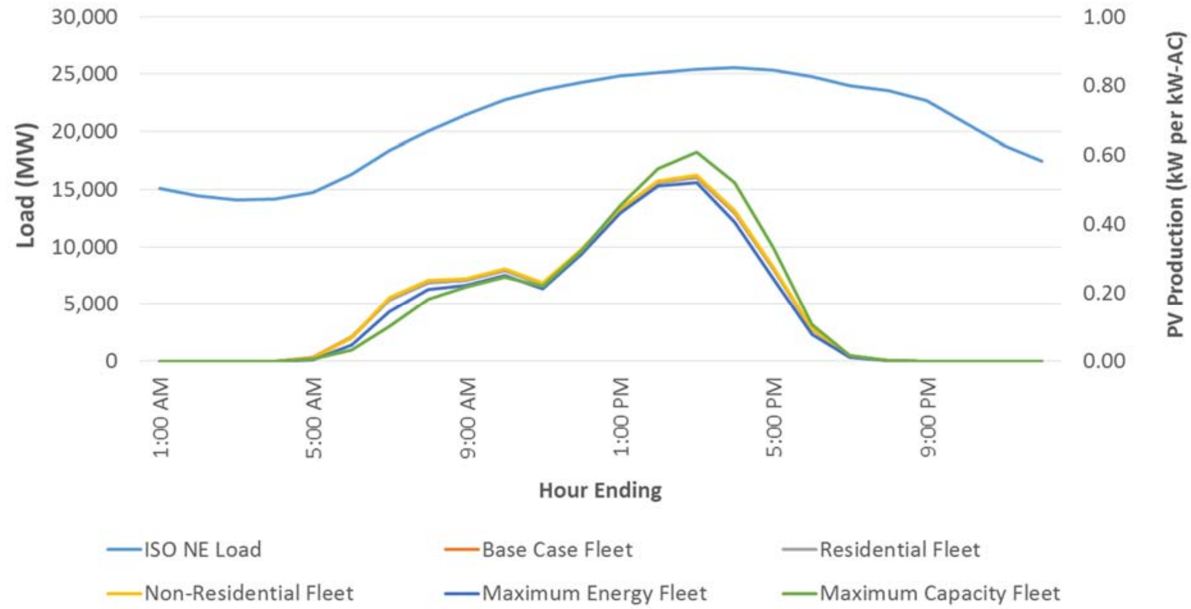
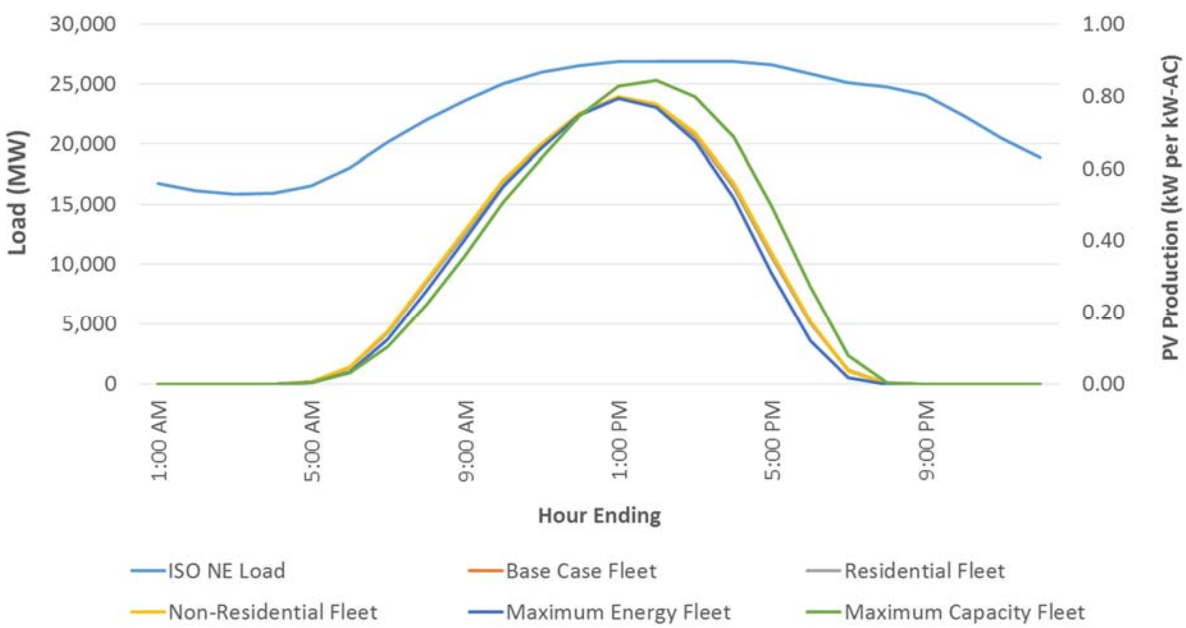


Figure 17. Normalized Fleet Production vs. ISO NE Load on 2013 Peak Load Day – July 19, 2013



High Penetration Scenario – Changes to Load Profile

Because fleet profiles provide normalized values, they can be easily scaled to explore various solar PV penetration levels. Average annual energy consumption in the Maine load zone for 2011-2013 was 11,324,249 MWh. To produce 5% of that energy (566,212 MWh) would require a capacity of 348 MW-AC for the Base Case fleet.

The single day with the highest load in the Main load zone during the three-year period was July 22, 2011. By scaling the production data for the Base Case flet, Figure 18 shows what the Maine load could have looked like on a peak load day in a high penetration scenario with 348 MW-AC of installed solar PV. Similar net load curves are shown for peak days in 2012 and 2013 in Figure 19 and Figure 20, respectively.

Figure 18. Maine Load Zone Peak 2011 Load Day – July 22, 2011

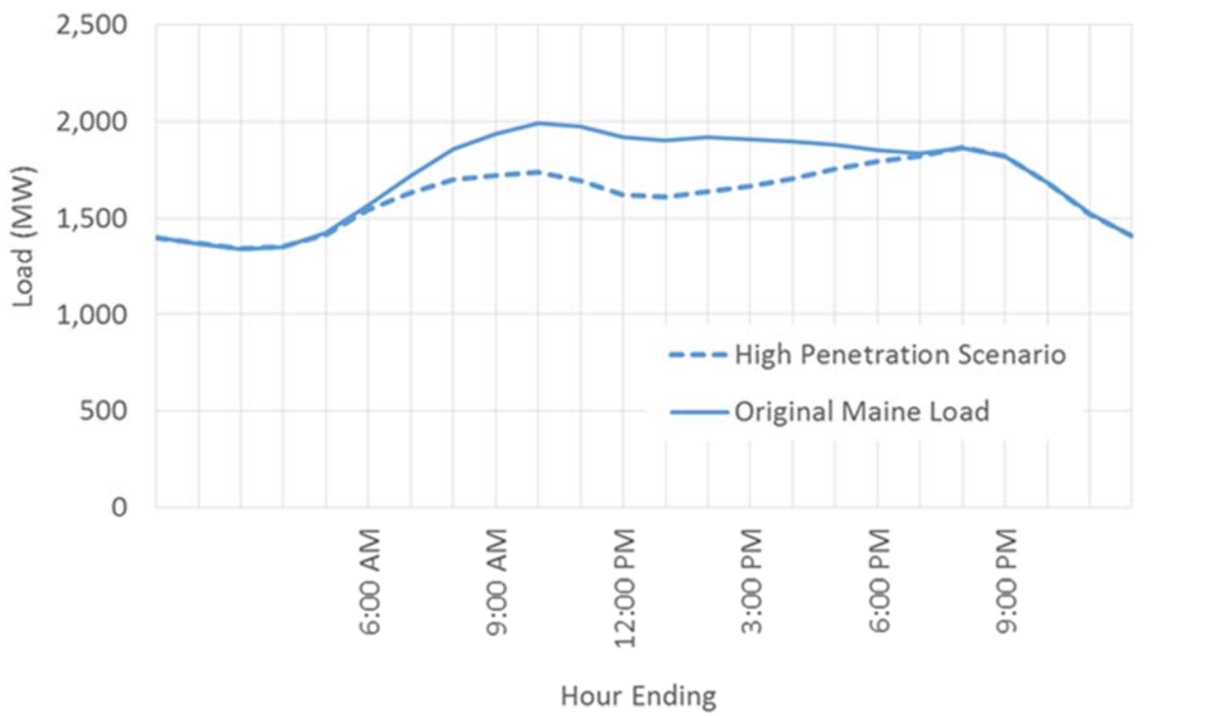


Figure 19. Maine Load Zone Peak 2012 Load Day – August 3, 2012

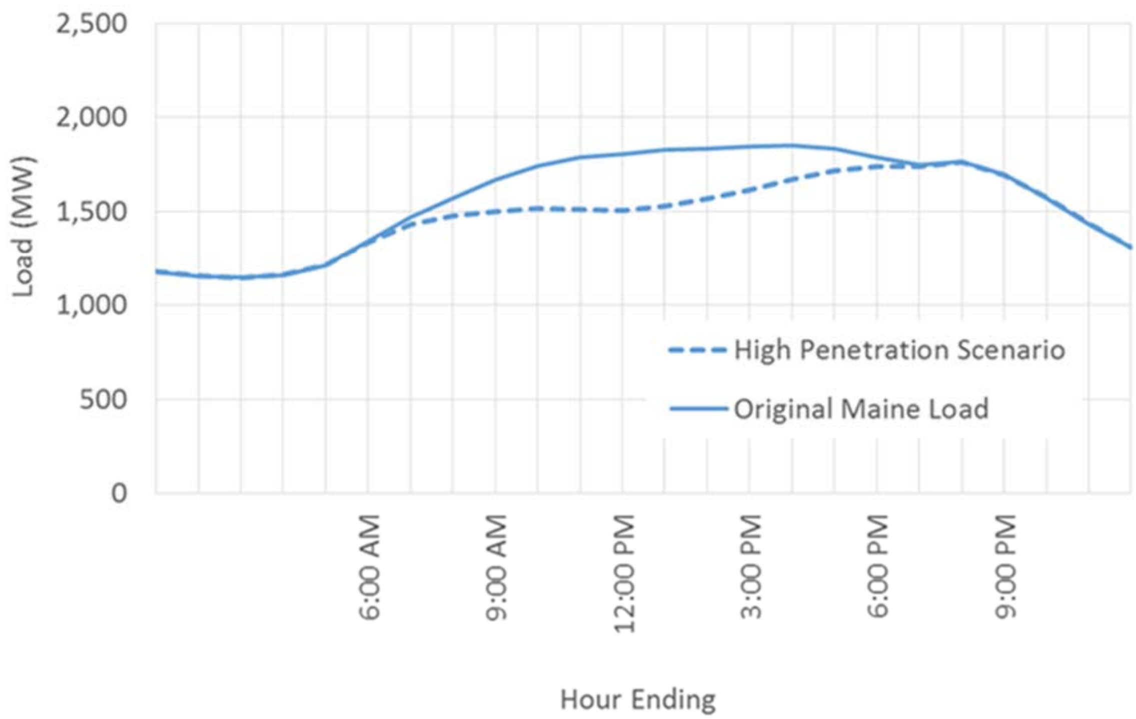
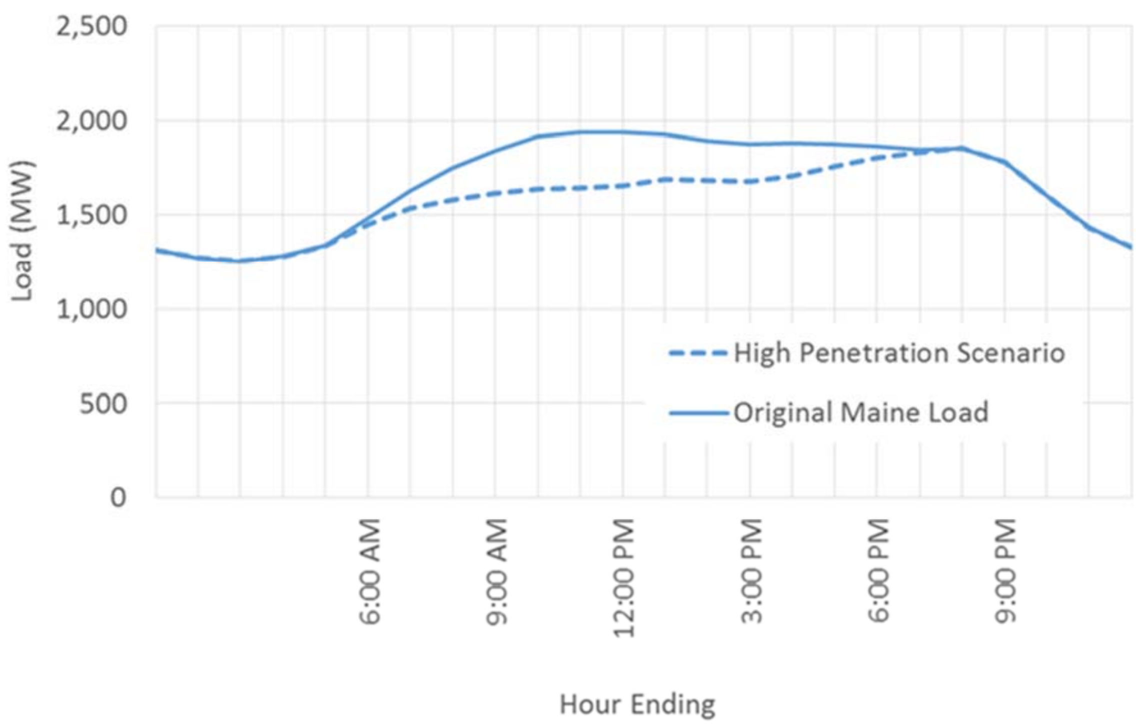


Figure 20. Maine Load Zone Peak 2013 Load Day – July 16, 2012



A few comments are worth noting about these curves. First, the addition of 348 MW of solar shifts the curve, resulting in a new peak. For 2011, the Maine load zone peak shifted from the hour ending 10 am to the hour ending 8 pm.

Second, the mid-day ramp rates appear to decline with increasing penetration. It is possible that this would mean that new load following capacity would not have to handle current ramp rates, and this potentially could mean that lower cost regulation resources would be needed. This is not quantified under this study, but may be worthy of additional research. If the addition of solar continued beyond 348 MW, then the afternoon ramp rate would increase, calling for more flexible resources that are able to handle faster ramping.

Third, the curves illustrate how in high penetration scenarios, the ELCC is going to decline. ELCCs calculated for the high penetration scenario are done by first deriving the new load curve as illustrated by the dotted lines and then by applying the 1 kW-AC Base Case resource. In other words, the ELCC is not calculated for the full 348 MW, but only a 1 kW PV resource applied to the high penetration load shape. In all three sample peak load days shown, the new peak occurs after sunset.

Appendix 3 – Technical Factors

ELCC, PLR, and First Year Avoided Energy are calculated as described in the methodology, and these are shown in Table 14. Since the same PV Fleet Production profile was used state-wide for all of the three utility regions based on the ISO-NE hourly load shape, the ELCC corresponding to a given fleet is used for all of the distribution utilities. For example, the Base Case ELCC (prior to inclusion of loss savings) is 54.4%. This is used for CMP, BHD, and MPD.

PLRs are calculated separately for each utility based on their unique distribution load profile. However, since the Avoided Distribution Capital Cost was not included in the study (see reasoning in the methodology), these values were not used and are provided here for reference. Note that the monthly average transmission peak load reduction was calculated separately for each utility, and these are described more fully in the transmission cost calculations of Appendix 4.

For simplicity, the distribution loss factors were combined for all three utility regions, weighted by average load. The peak losses thus calculated were 6.84% and the annual average losses were 6.50%. Note that these refer to lost energy relative to energy entering the system. For example, for every 100 units of energy that enter the distribution system on peak, 6.84% is lost, and 93.16 units are delivered to customers (this differs from the convention referencing losses as a percentage delivered).

Note that by using distributed PV fleet production, ISO hourly loads, and loss percentages that are common state-wide across the three utility regions, the Loss Savings Factors for energy and ELCC are the same. These could have been calculated separately for each utility region. For example, a separate fleet could have been defined for the MPD region, and separate loss factors could have been used, but for simplicity this was not done.

Using these loss percentages, the hourly losses were calculated with and without PV. Annual avoided energy, ELCC, and PLR were each calculated with and without losses the corresponding and Loss Savings Factors were calculated as described in the methodology. Results are shown in Table 15. For example, the Base Case energy Loss Savings Factor is 6.2%.

Table 14. Technical Factors

	Load Data	Base	Res. Proxy	Non-Res. Proxy	Max Enery	Max Cap.	High Pen.
No Losses							
ELCC							
	ISO-NE	54.4%	54.5%	55.0%	51.8%	60.4%	52.5%
PLR							
	CMP	72.9%	72.8%	73.6%	72.5%	64.0%	0.1%
	BHD	72.9%	72.8%	73.6%	72.5%	64.0%	0.2%
	MPS	0.5%	0.5%	0.5%	0.7%	0.8%	0.5%
First Yr. Avoided Energy							
	ISO-NE	1628	1638	1621	1738	1671	1628
With Losses							
	Load Data	**Base**	**Res. Proxy**	**Non-Res. Proxy**	**Max Enery**	**Max Cap.**	**High Pen.**
ELCC							
	ISO-NE	59.4%	59.5%	60.2%	57.0%	66.4%	57.5%
PLR							
	CMP	80.6%	80.4%	81.3%	80.1%	70.7%	0.1%
	BHD	80.8%	80.7%	81.6%	80.3%	71.0%	0.2%
	MPS	0.5%	0.5%	0.5%	0.7%	0.8%	0.5%
Avg. Annual Avoided Energy							
	ISO-NE	1729	1740	1722	1846	1776	1729

Table 15. Loss Savings Factors

Loss Savings Factor	Base	Res. Proxy	Non-Res. Proxy	Max Enery	Max Cap.	High Pen
Energy	6.2%	6.2%	6.2%	6.2%	6.2%	6.2%
ELCC	9.3%	9.3%	9.5%	10.0%	9.8%	9.5%
PLR-CMP	10.5%	10.5%	10.5%	10.5%	10.5%	10.6%
PLR-BHD	10.9%	10.9%	10.9%	10.9%	10.9%	10.9%
PLR-MPS	4.3%	4.3%	4.3%	4.3%	4.3%	4.2%

Appendix 4 – Cost Calculations

Study Assumptions

Assumptions are shown for the Table 16. These are described further below.

The Load Analysis Period was defined as the three year period January 2011 to December 2013. Hourly Fleet modeling was performed for this period, and the technical results, such as ELCC and loss savings factors, were calculated using load data and the Fleet Production Profile for that period.

Table 16. CMP Base Case Assumptions

Economic Factors		
Start Year for VOS applicability	2016	
Discount rate (WACC)	10.32%	per year
Discount Rate - Environmental	3.00%	per year
General escalation rate	1.80%	per year
Technical Factors		
ELCC (no loss)	54.4%	% of rating
Loss Savings - Energy	6.2%	% of PV output
Loss Savings - ELCC	9.3%	% of PV output
Solar		
First year annual energy	1628	kWh per kW-AC
PV degradation rate	0.5%	per year
PV life	25	years
Other		
First Year Avoided Energy Cost	57.49	$ per MWh
Reserve planning margin	13.6%	%
Installed cost of reserve capacity	$16.23	$ per kW-mo
Total Operating Reserves	1.75%	% of solar cap.
First Year RNS Rate	$89.80	$ per kW-yr
Trans. Avg. Monthly Peak Reduction	0.239	kW per kW-AC
CCGT Heat Rate	7,615	BTU per kWh

Treasury Yields		
1 Year	0.1%	per year
2 Year	0.5%	
3 Year	0.9%	
5 Year	1.6%	
7 Year	2.1%	
10 Year	2.5%	
20 Year	3.1%	
30 Year	3.3%	
Energy DRIPE		
2016	$8.59	$ per MWh
2017	$33.31	
2018	$35.33	
2019	$36.63	
2020	$35.81	
2021	$31.01	
2022	$26.87	
2023	$19.95	
2024	$13.31	
2025	$6.79	
Displaced Emissions		
SO2	1.356	lbs per MWh
NOx	0.799	lbs per MWh
CO2	0.553	tons per MWh

Economic Factors

The analysis presumes that PV resources are added to the distribution system during 2015, while the costs and benefits are evaluated over the life of the resources (Base Case assumption of 25 years) starting in 2016.

The after-tax weighted cost of capital was provided by the two utilities. A breakdown of costs provided by CMP is shown in Table 17. The corresponding cost of capital for Emera (applicable to both BHD and MPD) was 7.37%

Table 17. CMP Weighted Cost of Capital, Year ending June 30, 2015

	Capitalization Percentage	Cost	Weighted Cost	Tax Gross-Up at 40.8045%	Weighted Cost
Common Equity	50.00%	9.45%	4.73%	3.26%	7.98%
Preferred Stock	0.02%	6.00%	0.00%	0.00%	0.00%
Long Term Debt	45.80%	5.00%	2.29%		2.29%
Short Term Debt	4.18%	1.20%	0.05%		0.05%
Total	100.00%		7.06%	3.26%	10.32%

The environmental discount rate corresponds to the social cost data sources. For example, 3% represents a mid-range value for the social cost of carbon as estimated by the EPA. This discount rate is used for both discounting future values as well as levelizing the environmental cost components.

The general escalation rate of 1.8% is the constant escalation rate corresponding to the change in the Gross Domestic Product (GDP) Chain-type Price Index between 2014 and 2039.

Technical and Solar Factors

ELCC and loss factors were calculated as described in the methodology, and the results are provided in Appendix 3.

First year annual energy derives from the Base Case fleet modeling, with results shown in Appendix 3. PV life and degradation are assumptions, and sensitivities are presented in Appendix 6.

The PV degradation rate represents the median value of systems from an NREL study of the literature.[36]

Avoided Energy Cost

The First Year Avoided Energy Cost is calculated separately for each fleet (Base Case, Residential Proxy, etc.) by multiplying the 2013 day-ahead LMP for the Maine load zone by the hourly output of each fleet and summing the results. For example, the total first year avoided energy costs for the Base Case is $95.84 per year for a normalized fleet rating of 1 kW-AC. The annual production for the base case is

[36] D. Jordan and S. Kurtz, *Photovoltaic Degradation Rates — An Analytical Review*, NREL/JA-5200-51664, June 2012.

1.667 MWh per kW-AC, so the overall First Year Avoided Energy Cost (as shown in Table 16) is $57.49 per MWh.

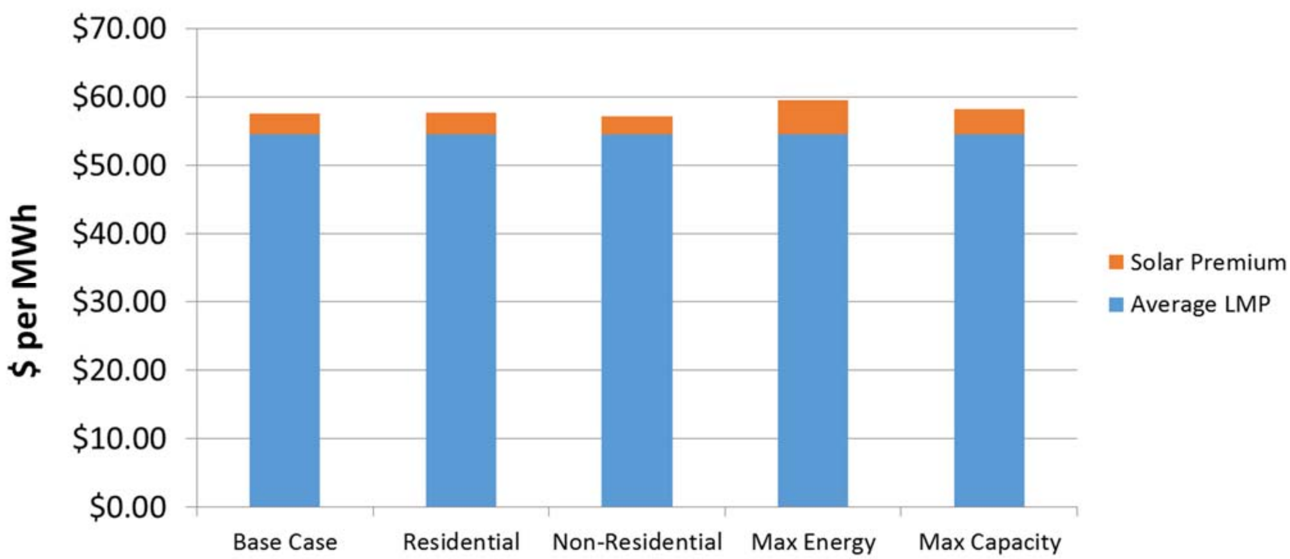
These costs assume no loss savings as if the solar resources were connected directly to the LMP node.

Table 18. First Year Avoided Energy Costs

	First Year Avoided Energy	First Year Avoided Energy Cost	
	MWh/kW	$/kW-yr	$/MWh
Base Case	1.667	95.84	$57.49
Residential	1.677	96.63	$57.63
Non-Residential	1.659	94.88	$57.18
Max Energy	1.780	105.98	$59.54
Max Capacity	1.708	99.37	$58.18

Figure 21 illustrates the "solar premium" for each fleet. The blue portion is the average LMP price ($54.48 per MWH and the orange portion is the premium above average. The premium is a small portion—only 5 percent above average for the Base Case, but in all cases the existence of a solar premium indicates that solar output is partially coincident with LMP prices.

Figure 21. Solar Premium by Fleet



Future electricity prices are escalated as described in the methodology. Calculations are shown in Table 19. In this table, NYMEX pricing (taken from February 12, 2015) is used to calculate annual escalation factors for the first 12 years. For years 13 to 25, the EIA natural gas price forecast for electric power production is used. Beyond year 25, required for the 30 year study scenario, escalation is assumed to continue at the same rate as the last five years.

Table 19. Assumed Electricity Price Escalation

		NYMEX ($/MMBtu)	Escalation	EIA Forecast ($/MMBtu)		Extended	Escalation	Esc. Factor
0	2015	2.944	0.0%	4.517			0.0%	1.000
1	2016	3.296	12.0%	4.482			12.0%	1.120
2	2017	3.580	8.6%	4.728			8.6%	1.216
3	2018	3.700	3.4%	5.007			3.4%	1.257
4	2019	3.780	2.1%	5.166			2.1%	1.284
5	2020	3.870	2.4%	5.366			2.4%	1.315
6	2021	3.975	2.7%	5.724			2.7%	1.350
7	2022	4.110	3.4%	5.980			3.4%	1.396
8	2023	4.229	2.9%	6.296			2.9%	1.437
9	2024	4.329	2.4%	6.769			2.4%	1.470
10	2025	4.410	1.9%	7.345			1.9%	1.498
11	2026	4.520	2.5%	7.841			2.5%	1.536
12	2027	4.672	3.4%	8.230			3.4%	1.587
13	2028			8.785	6.8%		6.8%	1.694
14	2029			9.367	6.6%		6.6%	1.807
15	2030			9.919	5.9%		5.9%	1.913
16	2031			10.044	1.3%		1.3%	1.937
17	2032			9.598	-4.4%		-4.4%	1.851
18	2033			9.923	3.4%		3.4%	1.914
19	2034			10.207	2.9%		2.9%	1.969
20	2035			10.614	4.0%		4.0%	2.047
21	2036			11.104	4.6%		4.6%	2.142
22	2037			11.500	3.6%		3.6%	2.218
23	2038			11.956	4.0%		4.0%	2.306
24	2039			12.844	7.4%		7.4%	2.477
25	2040			13.583	5.8%		5.8%	2.620
26	2041					5.1%	5.1%	2.752
27	2042					5.1%	5.1%	2.891
28	2043					5.1%	5.1%	3.038
29	2044					5.1%	5.1%	3.191

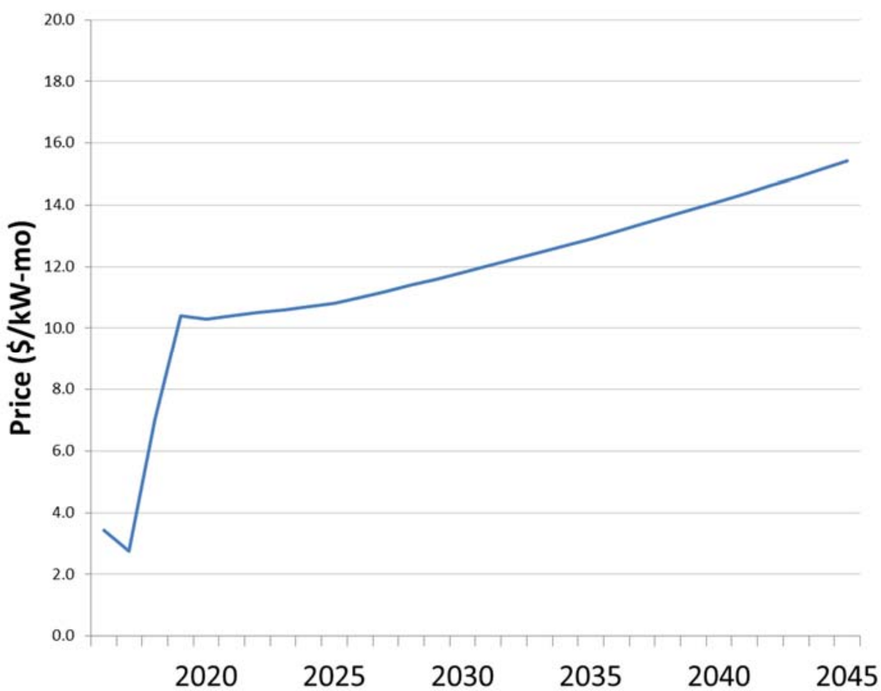
Avoided Generation Capacity Cost

As described in the methodology, FCA 6 through 8 were used[37] as the basis of generation capacity prices through 2018. Pricing corresponds to years beginning on June 1 and ending May 31 of the following year, but for simplicity, pricing for a given year was taken as the price in effect for January 1 of that year. A summary of these prices is as follows:

- FCA #6 (2015/16) Clearing Price was $3.434 / kW-mo
- FCA #7 (2016-17) Maine Clearing Price was $2.744
- FCA#8 (17-18) Maine Administrative Price was $7.025/kW-mo. The clearing price was $15, but insufficient competition triggered an existing resources payment rate which was used for the study.

For years beyond 2018, the pricing forecast was used as described in the methodology. The resulting set of capacity prices used for the study, then, is shown in Figure 22.

Figure 22. Assumed Capacity Prices ($/kW-mo)



[37] ISO-NE "Forward Capacity Market (FCA 6) Result Report," "FCA 7 Auction Results," "FCA 8 Auction Results" available at http://www.iso-ne.com/isoexpress/web/reports/auctions/-/tree/fcm-auction-results

Avoided Reserve Generation Capacity Cost

The ISO calculates its Annual Resulting Reserve Margin using a formula based on Net ICR. For the year 2027/18, the resulting value[38] was 13.6%, and this value was used for the reserve capacity margin. This value is included in Table 16.

Solar Integration Cost

According to the New England Wind Integration Study (NEWIS)[39] for the 2.5% wind energy scenario, the average required Total Operating Reserve (TOR) increases from 2,250 MW to 2,270 MW as compared to the no wind energy scenario baseline. The incremental TOR is then 20 MW (2,270 MW - 2,250 MW).

Dividing 20 MW by the incremental wind capacity of 1,140 MW results in an incremental TOR of 1.75 percent of incremental renewable capacity.

Costs are based on an assumed capital cost of $16.23 per kW-mo, corresponding to an LMS100 aeroderivative gas turbine as described in a NEPOOL Markets Committee study.[40]

The incremental TOR and the cost per kW-mo are included in the Table 16 input assumptions.

Avoided Transmission Capacity Cost

For each utility service territory, the utility's peak load reduction due to solar (without losses) was calculated for each month over the three year Load Analysis Period, shown in Figure 23. As described in the methodology, these values were averaged for each region. For example, the average of the Base

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[38] ISO New England Installed Capacity Requirement, Local Sourcing Requirements, and Maximum Capacity Limit for the 2017/18 Capacity Commitment Period, ISO New England, Inc., January 2014, available at http://www.iso-ne.com/genrtion_resrcs/reports/nepool_oc_review/2014/icr_2017_2018_report_final.pdf

[39] Page 22, study available at http://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/prtcpnts_comm/pac/reports/2010/newis_report.pdf

[40] S. Newell, et al., Net CONE for the ISO-NE Demand Curve, presented to NEPOOL Markets Committee, February 11, 2014, available at http://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=3&cad=rja&uact=8&ved=0CC0QFjAC&url=http%3A%2F%2Fwww.iso-ne.com%2Fcommittees%2Fcomm_wkgrps%2Fmrkts_comm%2Fmrkts%2Fmtrls%2F2014%2Ffeb11122014%2Fa02b_the_brattle_group_stakeholder_inquiry_responses_net_cone_02_11_14.pptx&ei=J2LeVN6fK8i4oQT_qoDABw&usg=AFQjCNGFXOWgWD_h45SoafV-oNZQvVD83A&sig2=CgpAhPQK9t7bbYQuyPM20A&bvm=bv.85970519,d.cGU

Case resource in CMP was calculated by averaging the transmission peak load reduction for January 2011, February 2011, and so on for 36 months. These values are then average to give 23.9% of the solar resource, and this is included in the assumptions of Table 16. A similar calculation is done for each utility region and for each fleet scenario. Results are shown in Figure 24.

Figure 23. Monthly Transmission Peak Load Reductions

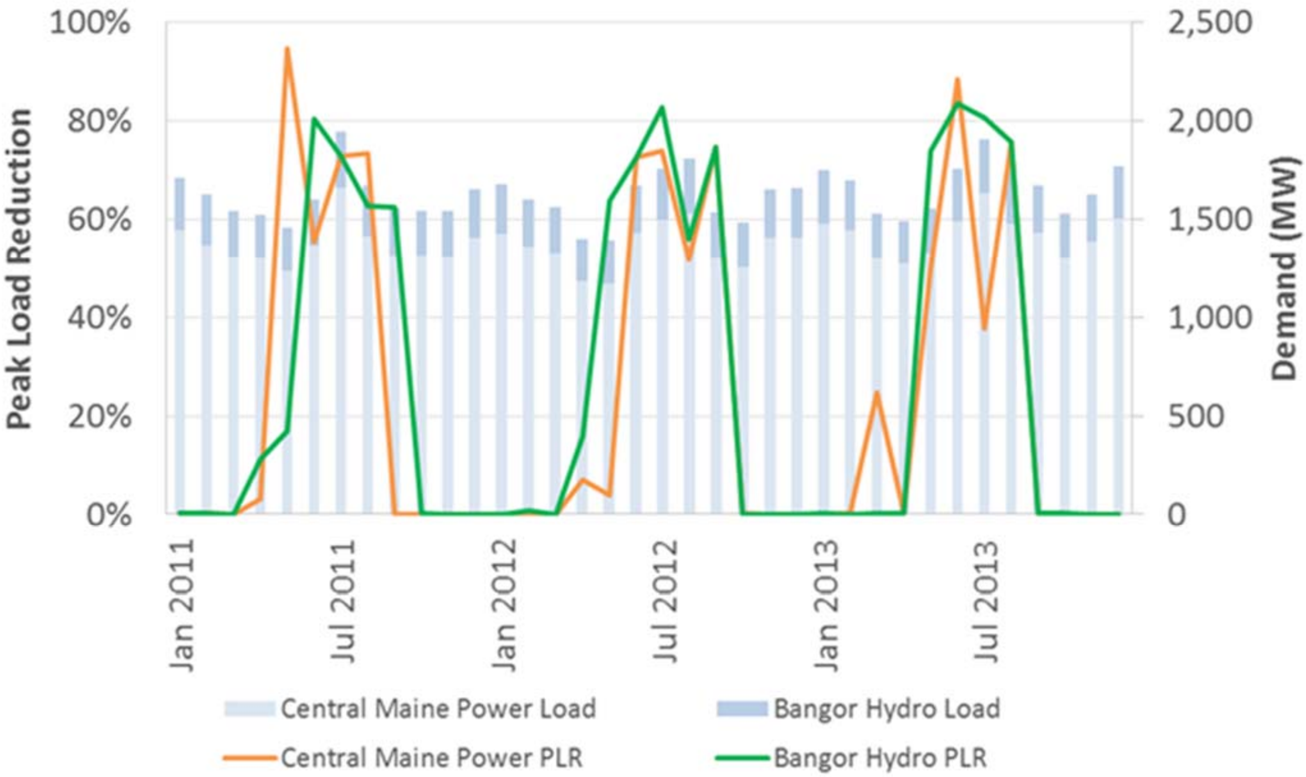
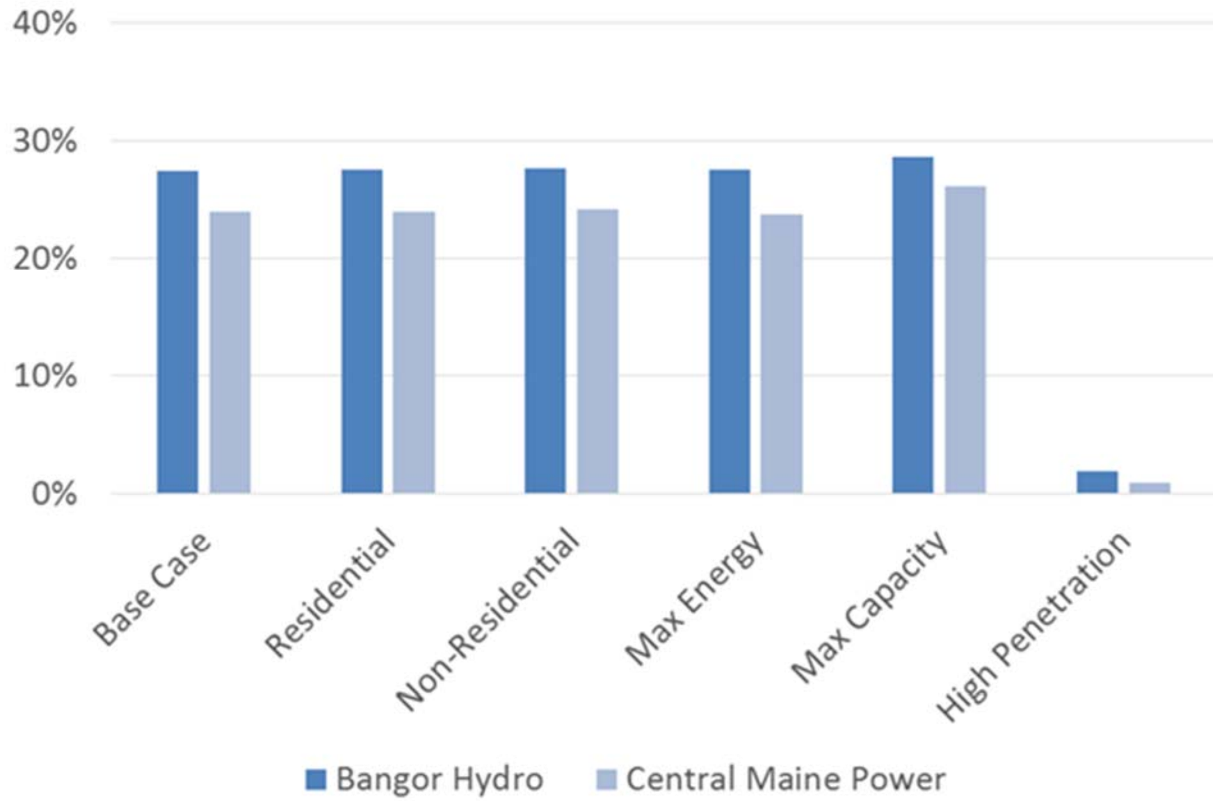


Figure 24. Transmission Peak Load Reductions by Utility and Fleet



Transmission prices are based on the costs and peak loads shown in Table 20. This table shows the calculation of $89.30 per kW of peak load.

For MPD, RNS rates do not apply, so the transmission benefit is set to zero.

According to the methodology the price would have to be adjusted to ensure that the total costs would be re-allocated based on a reduced load in Maine, allowing the ISO to recover all of the revenue requirements at a reduced total consumption. However, the marginal resource used in the study was only 1 kW-AC, and the resulting change in calculated price is insignificant. For simplicity, then, the published RNS rate was used for the study, and this is included as an input in Table 16.

Table 20. RNS Schedule 9 Price Calculation

	2013 Network Load (MW)
Central Maine Power Co.	1,418.44
Emera Maine	254.663
Fitchburg Gas & Electric Light Co.	76.971
New England Power Co.	6,019.71
Northeast Utilities	7,235.55
NSTAR Electric Co.	4,339.08
The United Illuminating Co.	734.933
VT Transco LLC	831.238
Total	20,910.58

	RNS Rates For June 1, 2014
Total NE Rev Req	$1,877,694,596
Total NE Loads - kW	20,910,580
Total NE RNS $ / kW-yr	$89.80

Displaced Pollutants

The displaced emissions were calculated using the EPA AVERT tool and a data file for the Northeast on an hourly basis. For example, for the Base Case fleet scenario, solar output (assuming no loss savings) was used to reduce hourly loads. Based on the change in dispatch of the generating units included in the data file, the change in total SO2, NOx, and CO2 was calculated for each hour and summed for the year. Results are shown in Table 21.

For example, for the Base Case fleet, 2.067 pounds of SO2 were avoided in 2011 for each MWh of solar production. This result was averaged with 2012 and 2013 to give 1.356 pounds per MWh. This value is entered into Table 16 as an input assumption. Values for NOx and CO2 and values for other fleet scenarios are calculated similarly.

Table 21. Displaced Emissions (AVERT results) by Fleet Scenario

		2011	2012	2013	Average
Base Case	SO_2 (lbs/MWh)	2.067	0.941	1.059	1.356
	NO_x (lbs/MWh)	0.867	0.706	0.824	0.799
	CO_2 (tons/MWh)	0.600	0.529	0.529	0.553
Res. Proxy	SO_2 (lbs/MWh)	2.067	0.941	1.059	1.356
	NO_x (lbs/MWh)	0.867	0.706	0.824	0.799
	CO_2 (tons/MWh)	0.600	0.529	0.529	0.553
Non-Res. Proxy	SO_2 (lbs/MWh)	2.067	0.941	1.125	1.378
	NO_x (lbs/MWh)	0.867	0.706	0.875	0.816
	CO_2 (tons/MWh)	0.600	0.529	0.563	0.564
Max. Energy	SO_2 (lbs/MWh)	2.063	0.889	1.111	1.354
	NO_x (lbs/MWh)	0.813	0.667	0.833	0.771
	CO_2 (tons/MWh)	0.625	0.556	0.556	0.579
Max. Capacity	SO_2 (lbs/MWh)	1.938	0.941	1.118	1.332
	NO_x (lbs/MWh)	0.813	0.706	0.882	0.800
	CO_2 (tons/MWh)	0.563	0.588	0.588	0.580
High Penetration	SO_2 (lbs/MWh)	2.067	0.824	1.000	1.297
	NO_x (lbs/MWh)	0.867	0.647	0.765	0.759
	CO_2 (tons/MWh)	0.600	0.529	0.529	0.553

The SO_2 and NO_x emissions rates calculated by AVERT are larger than marginal emission rates reported by ISO-NE in its 2013 Electric Generator Air Emissions Report.[41] For example, using the Locational Marginal Unit (LMU) method, which is based on production from the units that set the hourly LMP, the 2013 ISO-NE marginal rates for emitting units for SO_2 and NO_x are 0.69 lb per MWh and 0.42 lb per MWh, respectively. This compares to the AVERT results of 1.059 and 0.824, respectively.

The discrepancy has not been investigated, except to note that the Northeast data file used as an input to AVERT includes New York, which is not part of the ISO-NE control area. A different fuel mix in New York (e.g., higher coal usage) may skew the result. The discrepancy may also be due to the fact that the hourly weightings in the AVERT analysis are solar-weighted, while the ISO-NE are not, and even include non-solar hours.

An additional comparison may be made using the Fuel Type Assumed (FTA) method based on units fueled with oil and natural gas (i.e., without coal). The ISO-NE reports 2013 FTA emissions rates for SO_2 and NO_x of just 0.11 and 0.16 lb per MWh, respectively, significantly lower than the AVERT results.

[41] The report is found at http://www.iso-ne.com/static-assets/documents/2014/12/2013_emissions_report_final.pdf. See Table 1-3 for LMU marginal rates and 1-2 for FTA marginal emission rates.

These lower rates may be more indicative of emissions going forward, rather than historical rates. If the FTA rates were used rather than the AVERT results assumed for this study, the displaced emissions and the net social costs calculated below would be reduced to 8% and 20% of the values calculated here for SO2 and NOx, respectively. Although ISO-NE's marginal rate is somewhat illustrative, since that rate is an annual average marginal emission rate across all hours of the year, it is not ideal because it includes hours when solar does not generate (at night).

Going forward it would preferable to use the data set utilized by ISO-NE in the 2013 Electric Generator Air Emissions Report with an hourly analysis of PV output like the methodology used in the AVERT tool. Assumptions as to long-term emission rate declines should be included in the levelized analysis.

Net Social Cost of Carbon, SO2, and NOx

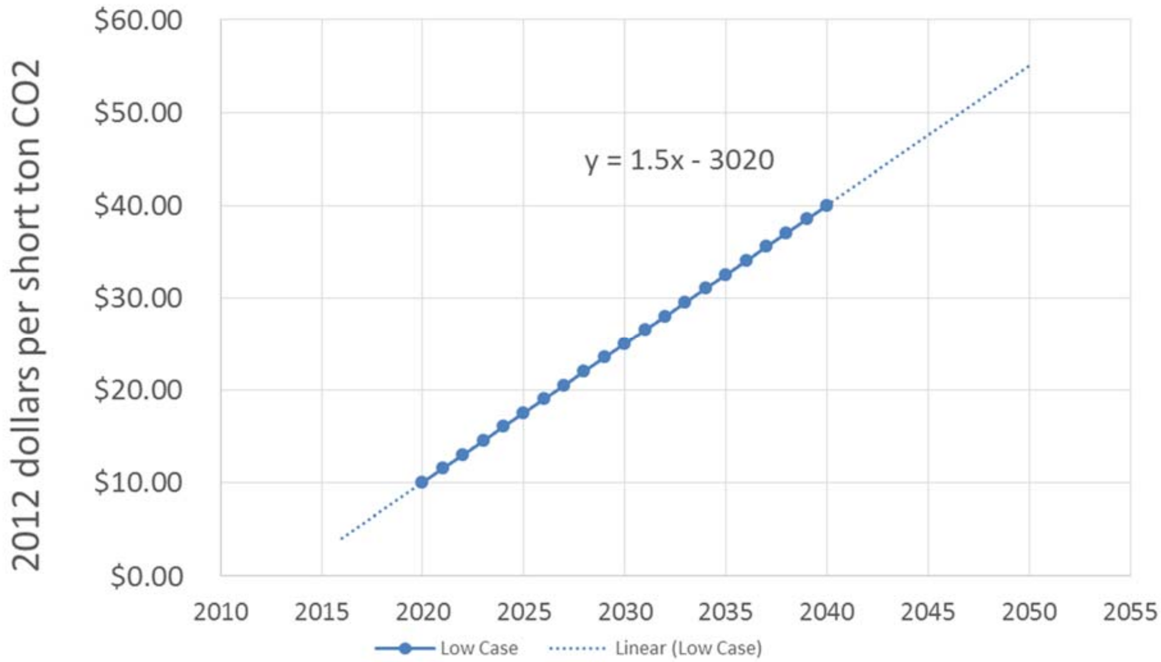
The net social costs of these pollutants were calculated as described in the methodology, subtracting out compliance costs that are embedded in the LMPs.

The net social cost of carbon (SCC) calculation is illustrated in Table 22. For each year, the SCC is converted from 2007 dollars per metric ton to current dollars per short ton. RGGI "embedded" pricing is then converted to current dollars per short ton. Note that the Synapse pricing forecasts begin with year 2020 and end with year 2040, so values on either side of these are linearly extrapolated as shown in Figure 25. Net costs are the difference between SCC and market price forecasts. For example, in the year 2020, the projected market price of $11.53 per ton is subtracted from the SCC of $49.19 per ton to give the net SCC of $37.66 per ton.

Table 22. Net Social Cost of Carbon

	Social Cost of Carbon			Synapse RGGI Carbon Prices (Low Case)		
Year	2007 $/metric ton CO2, 3.0% avg. discount rate	2007 $/short ton CO2, 3.0% avg. discount rate	Current $/short ton CO2, 3.0% avg. discount rate	2012 $/short ton CO2	Current $/short ton CO2	Net SCC (Current $/short ton)
2016	$38.00	$34.47	$40.48	$4.00	$4.30	$36.18
2017	$39.00	$35.38	$42.29	$5.50	$6.01	$36.28
2018	$40.00	$36.29	$44.16	$7.00	$7.79	$36.36
2019	$42.00	$38.10	$47.20	$8.50	$9.63	$37.57
2020	$43.00	$39.01	$49.19	$10.00	$11.53	$37.66
2021	$43.00	$39.01	$50.08	$11.50	$13.50	$36.57
...						
2044	$65.00	$58.97	$114.10	$46.00	$81.41	$32.69
2045	$66.00	$59.87	$117.94	$47.50	$85.58	$32.36

Figure 25. Extrapolating Synapse CO2 Price Forecasts



For each year, the net SCC cost is then multiplied by the displaced emissions per year as shown in Table 31 of Appendix 5. For example in the 2020 Base Case, the net SCC is $37.66 per ton, the displaced CO2 (see AVERT result, Table 21) is 0.553 tons of CO2 per MWh of solar, and the amount of electricity production in 2020 is 1.596 MWh per kW of solar. So, the benefit is $37.66 x 0.553 x 1.596 = $33 per kW.

For SO2, the calculation is similar. For example, the EPA social cost of SO2 (2020, midpoint of East Region, 3% discount rate) is $65,000 per ton in 2011 dollars. As shown in Table 23, this is converted in 2020 to a current cost of $76,320.88. The most recent EPA spot auction clearing price is $0.35 per ton (2014 dollars), and this is adjusted to $0.39 per ton for 2020 displaced emissions. Subtracting the clearing price from the social cost and converting from tons to pounds gives a benefit of $38.16 per pound of SO2. This value is then multiplied by the displaced emissions (Table 21) of 1.356 pounds per MWh and by the annual solar production of 1.596 MWh per year as shown in Table 32 to give a benefit of $83 per kW in 2020.

Table 23. Net Social Cost of SO2

Year	SO2 Benefit (Current $/ton)	Spot Auction Clearing Price ($/ton)	Net SO2 Social Cost (Current $/ton)	Net SO2 Social Cost (Current $/lb)
2016	$71,064.43	$0.36	$71,064.06	$35.53
2017	$72,343.58	$0.37	$72,343.22	$36.17
2018	$73,645.77	$0.38	$73,645.39	$36.82
2019	$74,971.39	$0.38	$74,971.01	$37.49
2020	$76,320.88	$0.39	$76,320.49	$38.16
2021	$77,694.65	$0.40	$77,694.26	$38.85
...				
2044	$117,108.93	$0.60	$117,108.34	$58.55
2045	$119,216.90	$0.61	$119,216.29	$59.61

In the case of NOX, there are no embedded costs, so the social cost and net social costs are the same thing. There are two costs to consider, one with NOx as PM2.5 and one with NOx as ozone. Midpoint social costs for these are $10,850 and $11,800 per ton (2011 dollars), respectively. These total $22,650 per ton.

Costs are applied each year. For example, in 2020, the social cost in current dollars is $26,594 per ton, or $13.30 per pound. These are multiplied by the NOx displacement of 0.799 lb per MWh and the annual solar production of 1.596 MWh per year to give $17 per kW of solar for 2020.

Market Price Response

DRIPE costs were calculated as described in the methodology and the results are shown in Table 24 and Table 25 for energy and capacity, respectively. The energy DRIPE costs are dependent upon fleet because the percentage production during winter and summer varies. For example, in the Base Case, 19.1 percent of production occurs during the winter off-peak hours, as compared to 20% for the Maximum Capacity fleet.

The resulting energy DRIPE values are included in Table 16. For example, in 2016, the energy DRIPE value is $8.59 per MWh, and this is shown as one of the input assumptions. Capacity DRIPE values are not fleet dependent. These are not included in Table 16 but are shown in the annual calculations of Appendix 5.

Table 24.Energy DRIPE

	Base Case	Residential	Non-Residential	Max Energy	Max Capacity	Base Case High Penetration
Energy production distribution						
% winter off-peak	19.1%	19.2%	18.9%	20.0%	18.6%	19.1%
% winter on-peak	40.3%	40.4%	40.0%	42.5%	41.6%	40.3%
% summer off-peak	13.3%	13.2%	13.5%	12.1%	12.4%	13.3%
% summer on-peak	27.3%	27.2%	27.6%	25.4%	27.3%	27.3%
Energy DRIPE ($/MWh)						
2016	$8.59	$8.60	$8.59	$8.67	$8.71	$8.59
2017	$33.31	$33.34	$33.29	$33.59	$33.74	$33.31
2018	$35.33	$35.35	$35.32	$35.57	$35.77	$35.33
2019	$36.63	$36.64	$36.65	$36.72	$37.06	$36.63
2020	$35.81	$35.82	$35.82	$35.87	$36.22	$35.81
2021	$31.01	$31.02	$31.03	$31.07	$31.37	$31.01
2022	$26.87	$26.88	$26.87	$26.96	$27.18	$26.87
2023	$19.95	$19.96	$19.96	$20.00	$20.18	$19.95
2024	$13.31	$13.31	$13.31	$13.36	$13.46	$13.31
2025	$6.79	$6.79	$6.79	$6.81	$6.87	$6.79

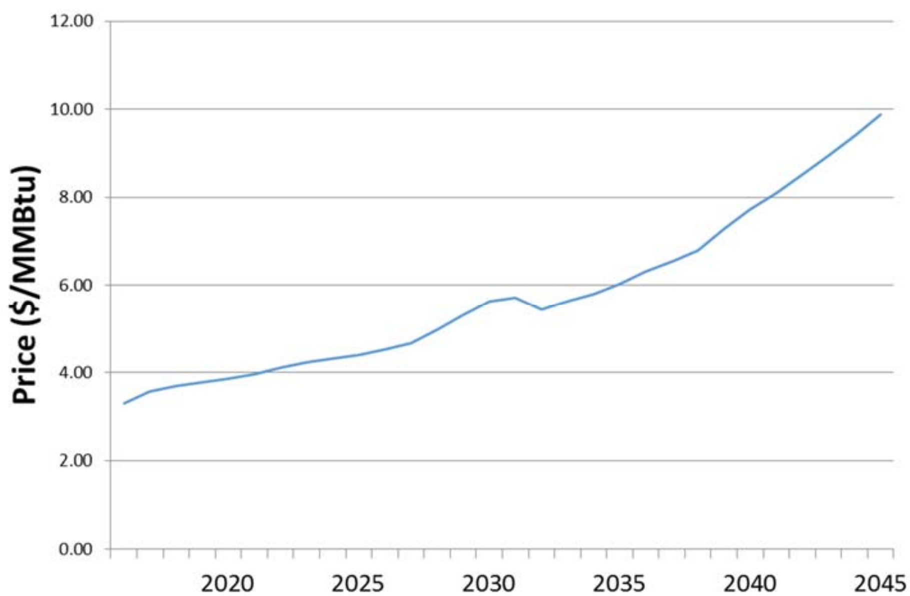
Table 25.**Capacity DRIPE ($/kW)**

	ME	ISO	Total	12 months
2016	0	0	$0.00	$0.00
2017	0	0	$0.00	$0.00
2018	0	0	$0.00	$0.00
2019	$1.75	$21.72	$23.47	$281.67
2020	$1.48	$18.47	$19.95	$239.39
2021	$1.20	$14.97	$16.18	$194.12
2022	$0.91	$11.45	$12.36	$148.36
2023	$0.61	$7.76	$8.37	$100.48
2024	$0.47	$5.92	$6.38	$76.61
2025	$0.31	$4.00	$4.31	$51.73
2026	$0.16	$2.03	$2.19	$26.24

Avoided Fuel Price Uncertainty

The calculation of avoided fuel price uncertainty requires an estimate of future fuel prices and the amount of displaced fuel. The assumed fuel price escalation is shown in Figure 26. These are calculated from the escalation factors in Table 26. For simplicity, only natural gas is considered for this calculation.

Figure 26. Assumed Fuel Price Escalation



The heat rate of the displaced unit of 7515 Btu per kWh is taken as the EIA average tested heat rate for natural gas combined cycle, 2012.[42] This is used as an input assumption in Table 16.

[42] http://www.eia.gov/electricity/annual/html/epa_08_02.html

Appendix 5 – Annual VOS Calculations

The tables that follow show the details of the annual cost calculations for Central Maine Power, Base Case. This is provided as an example calculation. Calculations for the other utility service areas and scenarios follow this same format.

Table 26. Economic Factors

Year	Analysis Year	Utility Discount Factor	Risk-Free Discount Factor	Environ. Discount Factor	Gen. Esclation Factor	Fuel Escalation Factor	Fleet Production kWh	Fleet Capacity kW
2016	0	1.000	1.000	1.000	1.000	1.000	1,628	1.000
2017	1	0.906	0.999	0.971	1.018	1.086	1,620	0.995
2018	2	0.822	0.991	0.943	1.036	1.123	1,612	0.990
2019	3	0.745	0.974	0.915	1.055	1.147	1,604	0.985
2020	4	0.675	0.951	0.888	1.074	1.174	1,596	0.980
2021	5	0.612	0.922	0.863	1.093	1.206	1,588	0.975
2022	6	0.555	0.894	0.837	1.113	1.247	1,580	0.970
2023	7	0.503	0.862	0.813	1.133	1.283	1,572	0.966
2024	8	0.456	0.835	0.789	1.153	1.313	1,564	0.961
2025	9	0.413	0.807	0.766	1.174	1.338	1,556	0.956
2026	10	0.374	0.778	0.744	1.195	1.372	1,548	0.951
2027	11	0.339	0.755	0.722	1.217	1.418	1,541	0.946
2028	12	0.308	0.731	0.701	1.239	1.514	1,533	0.942
2029	13	0.279	0.707	0.681	1.261	1.614	1,525	0.937
2030	14	0.253	0.684	0.661	1.284	1.709	1,518	0.932
2031	15	0.229	0.660	0.642	1.307	1.730	1,510	0.928
2032	16	0.208	0.637	0.623	1.330	1.654	1,503	0.923
2033	17	0.188	0.614	0.605	1.354	1.710	1,495	0.918
2034	18	0.171	0.591	0.587	1.379	1.758	1,488	0.914
2035	19	0.155	0.568	0.570	1.403	1.829	1,480	0.909
2036	20	0.140	0.546	0.554	1.429	1.913	1,473	0.905
2037	21	0.127	0.527	0.538	1.454	1.981	1,465	0.900
2038	22	0.115	0.508	0.522	1.481	2.060	1,458	0.896
2039	23	0.104	0.490	0.507	1.507	2.213	1,451	0.891
2040	24	0.095	0.472	0.492	1.534	2.340	1,443	0.887
2041	25	0.086	0.454	0.478	1.562	2.458	0	0.000
2042	26	0.078	0.437	0.464	1.590	2.583	0	0.000
2043	27	0.070	0.421	0.450	1.619	2.713	0	0.000
2044	28	0.064	0.405	0.437	1.648	2.851	0	0.000
2045	29	0.058	0.389	0.424	1.678	2.995	0	0.000

Table 27. Avoided Energy Cost Calculation

Year	Fleet Production	Avoided Energy			VOS		
	kWh/kW	$/kWh	$/kW	Disc. $/kW	Lev. $/kWh	$/kW	Disc. $/kW
2016	1,628	$0.057	$94	94	$0.076	$123	$123
2017	1,620	$0.062	$101	92	$0.076	$123	$111
2018	1,612	$0.065	$104	85	$0.076	$122	$100
2019	1,604	$0.066	$106	79	$0.076	$122	$91
2020	1,596	$0.068	$108	73	$0.076	$121	$82
2021	1,588	$0.069	$110	67	$0.076	$120	$74
2022	1,580	$0.072	$113	63	$0.076	$120	$66
2023	1,572	$0.074	$116	58	$0.076	$119	$60
2024	1,564	$0.076	$118	54	$0.076	$119	$54
2025	1,556	$0.077	$120	49	$0.076	$118	$49
2026	1,548	$0.079	$122	46	$0.076	$117	$44
2027	1,541	$0.082	$126	43	$0.076	$117	$40
2028	1,533	$0.087	$133	41	$0.076	$116	$36
2029	1,525	$0.093	$142	39	$0.076	$116	$32
2030	1,518	$0.098	$149	38	$0.076	$115	$29
2031	1,510	$0.099	$150	34	$0.076	$115	$26
2032	1,503	$0.095	$143	30	$0.076	$114	$24
2033	1,495	$0.098	$147	28	$0.076	$113	$21
2034	1,488	$0.101	$150	26	$0.076	$113	$19
2035	1,480	$0.105	$156	24	$0.076	$112	$17
2036	1,473	$0.110	$162	23	$0.076	$112	$16
2037	1,465	$0.114	$167	21	$0.076	$111	$14
2038	1,458	$0.118	$173	20	$0.076	$111	$13
2039	1,451	$0.127	$185	19	$0.076	$110	$11
2040	1,443	$0.135	$194	18	$0.076	$109	$10
2041	0	$0.141	$0	0	$0.076	$0	$0
2042	0	$0.148	$0	0	$0.076	$0	$0
2043	0	$0.156	$0	0	$0.076	$0	$0
2044	0	$0.164	$0	0	$0.076	$0	$0
2045	0	$0.172	$0	0	$0.076	$0	$0
				$1,163			$1,163

Table 28. Avoided Generation Capacity Cost

Year	Fleet Production	Fleet Capacity	Avoided Capacity			VOS		
	kWh/kW	kW	$/kW-mo	$/kW	Disc. $/kW	Lev. $/kWh	$/kW	Disc. $/kW
2016	1,628	1.000	$3.4	$41	41	$0.068	$110	$110
2017	1,620	0.995	$2.7	$33	30	$0.068	$110	$99
2018	1,612	0.990	$7.0	$83	69	$0.068	$109	$90
2019	1,604	0.985	$10.4	$123	92	$0.068	$109	$81
2020	1,596	0.980	$10.3	$121	82	$0.068	$108	$73
2021	1,588	0.975	$10.4	$122	74	$0.068	$108	$66
2022	1,580	0.970	$10.5	$122	68	$0.068	$107	$59
2023	1,572	0.966	$10.6	$123	62	$0.068	$106	$54
2024	1,564	0.961	$10.7	$123	56	$0.068	$106	$48
2025	1,556	0.956	$10.8	$124	51	$0.068	$105	$44
2026	1,548	0.951	$11.0	$125	47	$0.068	$105	$39
2027	1,541	0.946	$11.2	$127	43	$0.068	$104	$35
2028	1,533	0.942	$11.4	$129	40	$0.068	$104	$32
2029	1,525	0.937	$11.6	$130	36	$0.068	$103	$29
2030	1,518	0.932	$11.8	$132	33	$0.068	$103	$26
2031	1,510	0.928	$12.0	$134	31	$0.068	$102	$23
2032	1,503	0.923	$12.2	$136	28	$0.068	$102	$21
2033	1,495	0.918	$12.5	$137	26	$0.068	$101	$19
2034	1,488	0.914	$12.7	$139	24	$0.068	$101	$17
2035	1,480	0.909	$12.9	$141	22	$0.068	$100	$16
2036	1,473	0.905	$13.1	$143	20	$0.068	$100	$14
2037	1,465	0.900	$13.4	$144	18	$0.068	$99	$13
2038	1,458	0.896	$13.6	$146	17	$0.068	$99	$11
2039	1,451	0.891	$13.9	$148	15	$0.068	$98	$10
2040	1,443	0.887	$14.1	$150	14	$0.068	$98	$9
2041	0	0.000	$14.4	$0	0	$0.068	$0	$0
2042	0	0.000	$14.6	$0	0	$0.068	$0	$0
2043	0	0.000	$14.9	$0	0	$0.068	$0	$0
2044	0	0.000	$15.2	$0	0	$0.068	$0	$0
2045	0	0.000	$15.4	$0	0	$0.068	$0	$0
					$1,039			$1,039

Table 29. Solar Integration Cost

Year	Fleet Production	Fleet Capacity	Solar Integration Cost				VOS		
	kWh/kW	kW	$/kW-mo	TOR Pct (%)	$/kW	Disc. $/kW	Lev. $/kWh	$/kW	Disc. $/kW
2016	1,628	1.000	$16.23	1.75%	$3	$3	$0.005	$7	$7
2017	1,620	0.995	$16.52	1.75%	$3	$3	$0.005	$7	$7
2018	1,612	0.990	$16.82	1.75%	$3	$3	$0.005	$7	$6
2019	1,604	0.985	$17.12	1.75%	$4	$3	$0.005	$7	$5
2020	1,596	0.980	$17.43	1.75%	$4	$3	$0.005	$7	$5
2021	1,588	0.975	$17.74	1.75%	$4	$3	$0.005	$7	$4
2022	1,580	0.970	$18.06	1.75%	$4	$3	$0.005	$7	$4
2023	1,572	0.966	$18.39	1.75%	$4	$3	$0.005	$7	$4
2024	1,564	0.961	$18.72	1.75%	$4	$3	$0.005	$7	$3
2025	1,556	0.956	$19.06	1.75%	$4	$3	$0.005	$7	$3
2026	1,548	0.951	$19.40	1.75%	$4	$3	$0.005	$7	$3
2027	1,541	0.946	$19.75	1.75%	$4	$3	$0.005	$7	$2
2028	1,533	0.942	$20.10	1.75%	$4	$3	$0.005	$7	$2
2029	1,525	0.937	$20.47	1.75%	$4	$3	$0.005	$7	$2
2030	1,518	0.932	$20.83	1.75%	$4	$3	$0.005	$7	$2
2031	1,510	0.928	$21.21	1.75%	$4	$3	$0.005	$7	$2
2032	1,503	0.923	$21.59	1.75%	$4	$3	$0.005	$7	$1
2033	1,495	0.918	$21.98	1.75%	$4	$3	$0.005	$7	$1
2034	1,488	0.914	$22.38	1.75%	$4	$3	$0.005	$7	$1
2035	1,480	0.909	$22.78	1.75%	$4	$2	$0.005	$7	$1
2036	1,473	0.905	$23.19	1.75%	$4	$2	$0.005	$7	$1
2037	1,465	0.900	$23.61	1.75%	$4	$2	$0.005	$7	$1
2038	1,458	0.896	$24.03	1.75%	$5	$2	$0.005	$7	$1
2039	1,451	0.891	$24.46	1.75%	$5	$2	$0.005	$7	$1
2040	1,443	0.887	$24.90	1.75%	$5	$2	$0.005	$7	$1
2041	0	0.000	$25.35	1.75%	$0	$0	$0.005	$0	$0
2042	0	0.000	$25.81	1.75%	$0	$0	$0.005	$0	$0
2043	0	0.000	$26.27	1.75%	$0	$0	$0.005	$0	$0
2044	0	0.000	$26.75	1.75%	$0	$0	$0.005	$0	$0
2045	0	0.000	$27.23	1.75%	$0	$0	$0.005	$0	$0
						$70			$70

Table 30. Avoided Transmission Capacity Cost

Year	Fleet Production	Fleet Capacity	Avoided Transmission Capacity			VOS		
	kWh/kW	kW	$/kW-yr	$/kW	Disc.	Lev.	$/kW	Disc.
2016	1,628	1.000	$89.8	$90	90	$0.063	$103	$103
2017	1,620	0.995	$91.4	$91	82	$0.063	$102	$93
2018	1,612	0.990	$93.1	$92	76	$0.063	$102	$84
2019	1,604	0.985	$94.7	$93	70	$0.063	$101	$75
2020	1,596	0.980	$96.4	$95	64	$0.063	$101	$68
2021	1,588	0.975	$98.2	$96	59	$0.063	$100	$61
2022	1,580	0.970	$99.9	$97	54	$0.063	$100	$55
2023	1,572	0.966	$101.7	$98	49	$0.063	$99	$50
2024	1,564	0.961	$103.6	$100	45	$0.063	$99	$45
2025	1,556	0.956	$105.4	$101	42	$0.063	$98	$41
2026	1,548	0.951	$107.3	$102	38	$0.063	$98	$37
2027	1,541	0.946	$109.3	$103	35	$0.063	$97	$33
2028	1,533	0.942	$111.2	$105	32	$0.063	$97	$30
2029	1,525	0.937	$113.2	$106	30	$0.063	$96	$27
2030	1,518	0.932	$115.3	$107	27	$0.063	$96	$24
2031	1,510	0.928	$117.4	$109	25	$0.063	$95	$22
2032	1,503	0.923	$119.5	$110	23	$0.063	$95	$20
2033	1,495	0.918	$121.6	$112	21	$0.063	$94	$18
2034	1,488	0.914	$123.8	$113	19	$0.063	$94	$16
2035	1,480	0.909	$126.0	$115	18	$0.063	$93	$14
2036	1,473	0.905	$128.3	$116	16	$0.063	$93	$13
2037	1,465	0.900	$130.6	$118	15	$0.063	$92	$12
2038	1,458	0.896	$133.0	$119	14	$0.063	$92	$11
2039	1,451	0.891	$135.4	$121	13	$0.063	$91	$10
2040	1,443	0.887	$137.8	$122	12	$0.063	$91	$9
2041	0	0.000	$140.3	$0	0	$0.063	$0	$0
2042	0	0.000	$142.8	$0	0	$0.063	$0	$0
2043	0	0.000	$145.4	$0	0	$0.063	$0	$0
2044	0	0.000	$148.0	$0	0	$0.063	$0	$0
2045	0	0.000	$150.6	$0	0	$0.063	$0	$0
					$967			$967

Table 31. Net Social Cost of Carbon

Year	Fleet Production	Net Social Cost of Carbon				VOS		
	kWh/kW	ton/MWh	$/ton	$/kW	Disc.	Lev. $/kWh	$/kW	Disc.
2016	1,628	0.553	$36.181	$33	$33	$0.020	$32	$32
2017	1,620	0.553	$36.277	$32	$32	$0.020	$32	$31
2018	1,612	0.553	$36.364	$32	$31	$0.020	$32	$30
2019	1,604	0.553	$37.567	$33	$30	$0.020	$32	$29
2020	1,596	0.553	$37.657	$33	$30	$0.020	$32	$28
2021	1,588	0.553	$36.573	$32	$28	$0.020	$32	$27
2022	1,580	0.553	$36.624	$32	$27	$0.020	$32	$26
2023	1,572	0.553	$36.665	$32	$26	$0.020	$31	$26
2024	1,564	0.553	$36.696	$32	$25	$0.020	$31	$25
2025	1,556	0.553	$36.715	$32	$24	$0.020	$31	$24
2026	1,548	0.553	$36.724	$31	$23	$0.020	$31	$23
2027	1,541	0.553	$36.721	$31	$23	$0.020	$31	$22
2028	1,533	0.553	$36.706	$31	$22	$0.020	$31	$21
2029	1,525	0.553	$36.678	$31	$21	$0.020	$30	$21
2030	1,518	0.553	$36.638	$31	$20	$0.020	$30	$20
2031	1,510	0.553	$35.192	$29	$19	$0.020	$30	$19
2032	1,503	0.553	$35.100	$29	$18	$0.020	$30	$19
2033	1,495	0.553	$34.992	$29	$18	$0.020	$30	$18
2034	1,488	0.553	$34.870	$29	$17	$0.020	$30	$17
2035	1,480	0.553	$34.731	$28	$16	$0.020	$30	$17
2036	1,473	0.553	$34.577	$28	$16	$0.020	$29	$16
2037	1,465	0.553	$34.405	$28	$15	$0.020	$29	$16
2038	1,458	0.553	$34.217	$28	$14	$0.020	$29	$15
2039	1,451	0.553	$34.010	$27	$14	$0.020	$29	$15
2040	1,443	0.553	$33.785	$27	$13	$0.020	$29	$14
2041	0	0.553	$33.540	$0	$0	$0.020	$0	$0
2042	0	0.553	$33.276	$0	$0	$0.020	$0	$0
2043	0	0.553	$32.992	$0	$0	$0.020	$0	$0
2044	0	0.553	$32.686	$0	$0	$0.020	$0	$0
2045	0	0.553	$32.359	$0	$0	$0.020	$0	$0
					$553			$553

Table 32. Net Social Cost of SO2

Year	Fleet Production	Net Social Cost of SO2				VOS		
	kWh/kW	lb/MWh	$/lb	$/kW	Disc.	Lev. $/kWh	$/kW	Disc.
2016	1,628	1.356	$35.532	$78	$78	$0.058	$95	$95
2017	1,620	1.356	$36.172	$79	$77	$0.058	$94	$92
2018	1,612	1.356	$36.823	$80	$76	$0.058	$94	$89
2019	1,604	1.356	$37.486	$81	$75	$0.058	$93	$86
2020	1,596	1.356	$38.160	$83	$73	$0.058	$93	$83
2021	1,588	1.356	$38.847	$84	$72	$0.058	$93	$80
2022	1,580	1.356	$39.546	$85	$71	$0.058	$92	$77
2023	1,572	1.356	$40.258	$86	$70	$0.058	$92	$74
2024	1,564	1.356	$40.983	$87	$69	$0.058	$91	$72
2025	1,556	1.356	$41.721	$88	$67	$0.058	$91	$69
2026	1,548	1.356	$42.472	$89	$66	$0.058	$90	$67
2027	1,541	1.356	$43.236	$90	$65	$0.058	$90	$65
2028	1,533	1.356	$44.014	$91	$64	$0.058	$89	$63
2029	1,525	1.356	$44.807	$93	$63	$0.058	$89	$61
2030	1,518	1.356	$45.613	$94	$62	$0.058	$88	$58
2031	1,510	1.356	$46.434	$95	$61	$0.058	$88	$56
2032	1,503	1.356	$47.270	$96	$60	$0.058	$88	$55
2033	1,495	1.356	$48.121	$98	$59	$0.058	$87	$53
2034	1,488	1.356	$48.987	$99	$58	$0.058	$87	$51
2035	1,480	1.356	$49.869	$100	$57	$0.058	$86	$49
2036	1,473	1.356	$50.766	$101	$56	$0.058	$86	$48
2037	1,465	1.356	$51.680	$103	$55	$0.058	$85	$46
2038	1,458	1.356	$52.610	$104	$54	$0.058	$85	$44
2039	1,451	1.356	$53.557	$105	$53	$0.058	$85	$43
2040	1,443	1.356	$54.521	$107	$52	$0.058	$84	$41
2041	0	1.356	$55.503	$0	$0	$0.058	$0	$0
2042	0	1.356	$56.502	$0	$0	$0.058	$0	$0
2043	0	1.356	$57.519	$0	$0	$0.058	$0	$0
2044	0	1.356	$58.554	$0	$0	$0.058	$0	$0
2045	0	1.356	$59.608	$0	$0	$0.058	$0	$0
					$1,615			$1,615

Table 33. Net Social Cost of NOx

Year	Fleet Production	Net Social Cost of NOx				VOS		
	kWh/kW	lb/MWh	$/lb	$/kW	Disc.	Lev.	$/kW	Disc. $/kW
2016	1,628	0.799	$12.382	$16	$16	$0.012	$19	$19
2017	1,620	0.799	$12.604	$16	$16	$0.012	$19	$19
2018	1,612	0.799	$12.831	$17	$16	$0.012	$19	$18
2019	1,604	0.799	$13.062	$17	$15	$0.012	$19	$18
2020	1,596	0.799	$13.297	$17	$15	$0.012	$19	$17
2021	1,588	0.799	$13.537	$17	$15	$0.012	$19	$16
2022	1,580	0.799	$13.780	$17	$15	$0.012	$19	$16
2023	1,572	0.799	$14.029	$18	$14	$0.012	$19	$15
2024	1,564	0.799	$14.281	$18	$14	$0.012	$19	$15
2025	1,556	0.799	$14.538	$18	$14	$0.012	$19	$14
2026	1,548	0.799	$14.800	$18	$14	$0.012	$19	$14
2027	1,541	0.799	$15.066	$19	$13	$0.012	$18	$13
2028	1,533	0.799	$15.337	$19	$13	$0.012	$18	$13
2029	1,525	0.799	$15.613	$19	$13	$0.012	$18	$12
2030	1,518	0.799	$15.894	$19	$13	$0.012	$18	$12
2031	1,510	0.799	$16.181	$20	$13	$0.012	$18	$12
2032	1,503	0.799	$16.472	$20	$12	$0.012	$18	$11
2033	1,495	0.799	$16.768	$20	$12	$0.012	$18	$11
2034	1,488	0.799	$17.070	$20	$12	$0.012	$18	$10
2035	1,480	0.799	$17.377	$21	$12	$0.012	$18	$10
2036	1,473	0.799	$17.690	$21	$12	$0.012	$18	$10
2037	1,465	0.799	$18.009	$21	$11	$0.012	$18	$9
2038	1,458	0.799	$18.333	$21	$11	$0.012	$17	$9
2039	1,451	0.799	$18.663	$22	$11	$0.012	$17	$9
2040	1,443	0.799	$18.999	$22	$11	$0.012	$17	$8
2041	0	0.799	$19.341	$0	$0	$0.012	$0	$0
2042	0	0.799	$19.689	$0	$0	$0.012	$0	$0
2043	0	0.799	$20.043	$0	$0	$0.012	$0	$0
2044	0	0.799	$20.404	$0	$0	$0.012	$0	$0
2045	0	0.799	$20.771	$0	$0	$0.012	$0	$0
					$332			$332

Table 34. Market Price Response

Year	Fleet Production	Fleet Capacity	DRIPE Capacity		DRIPE Energy		DRIPE Total		VOS		
	kWh/kW	kW	$/kW	$	$/MWh	$	$	Disc. $	Lev.	$/kW	Disc. $/kW
2016	1,628	1.000	$0	$0	9	14	14	14	$0.062	$101	$101
2017	1,620	0.995	$0	$0	33	54	54	49	$0.062	$100	$91
2018	1,612	0.990	$0	$0	35	57	57	47	$0.062	$100	$82
2019	1,604	0.985	$282	$277	37	59	336	250	$0.062	$99	$74
2020	1,596	0.980	$239	$235	36	57	292	197	$0.062	$99	$67
2021	1,588	0.975	$194	$189	31	49	239	146	$0.062	$98	$60
2022	1,580	0.970	$148	$144	27	42	186	103	$0.062	$98	$54
2023	1,572	0.966	$100	$97	20	31	128	65	$0.062	$97	$49
2024	1,564	0.961	$77	$74	13	21	94	43	$0.062	$97	$44
2025	1,556	0.956	$52	$49	7	11	60	25	$0.062	$96	$40
2026	1,548	0.951	$26	$25	0	0	25	9	$0.062	$96	$36
2027	1,541	0.946	$0	$0	0	0	0	0	$0.062	$95	$32
2028	1,533	0.942	$0	$0	0	0	0	0	$0.062	$95	$29
2029	1,525	0.937	$0	$0	0	0	0	0	$0.062	$94	$26
2030	1,518	0.932	$0	$0	0	0	0	0	$0.062	$94	$24
2031	1,510	0.928	$0	$0	0	0	0	0	$0.062	$93	$21
2032	1,503	0.923	$0	$0	0	0	0	0	$0.062	$93	$19
2033	1,495	0.918	$0	$0	0	0	0	0	$0.062	$92	$17
2034	1,488	0.914	$0	$0	0	0	0	0	$0.062	$92	$16
2035	1,480	0.909	$0	$0	0	0	0	0	$0.062	$91	$14
2036	1,473	0.905	$0	$0	0	0	0	0	$0.062	$91	$13
2037	1,465	0.900	$0	$0	0	0	0	0	$0.062	$91	$12
2038	1,458	0.896	$0	$0	0	0	0	0	$0.062	$90	$10
2039	1,451	0.891	$0	$0	0	0	0	0	$0.062	$90	$9
2040	1,443	0.887	$0	$0	0	0	0	0	$0.062	$89	$8
2041	0	0.000	$0	$0	0	0	0	0	$0.062	$0	$0
2042	0	0.000	$0	$0	0	0	0	0	$0.062	$0	$0
2043	0	0.000	$0	$0	0	0	0	0	$0.062	$0	$0
2044	0	0.000	$0	$0	0	0	0	0	$0.062	$0	$0
2045	0	0.000	$0	$0	0	0	0	0	$0.062	$0	$0
								$948			$948

Table 35. Avoided Fuel Price Uncertainty

Year	Fleet Production	Fuel Price Uncertainty						VOS		
	kWh/kW	$/MMBtu	Heat Rate (Btu/kWh)	$/kW	Guar. Fuel Disc. $/kW	Non-Guar. Fuel Disc. $/kW	Hedge Disc. $/kW	Lev.	$/kW	Disc.
2016	1,628	3.30	7615	41	41	41	0	$0.035	$57	$57
2017	1,620	3.58	7615	44	44	40	4	$0.035	$57	$51
2018	1,612	3.70	7615	45	45	37	8	$0.035	$56	$46
2019	1,604	3.78	7615	46	45	34	11	$0.035	$56	$42
2020	1,596	3.87	7615	47	45	32	13	$0.035	$56	$38
2021	1,588	3.98	7615	48	44	29	15	$0.035	$56	$34
2022	1,580	4.11	7615	49	44	27	17	$0.035	$55	$31
2023	1,572	4.23	7615	51	44	25	18	$0.035	$55	$28
2024	1,564	4.33	7615	52	43	23	20	$0.035	$55	$25
2025	1,556	4.41	7615	52	42	22	21	$0.035	$54	$23
2026	1,548	4.52	7615	53	41	20	22	$0.035	$54	$20
2027	1,541	4.67	7615	55	41	19	23	$0.035	$54	$18
2028	1,533	4.99	7615	58	43	18	25	$0.035	$54	$17
2029	1,525	5.32	7615	62	44	17	26	$0.035	$53	$15
2030	1,518	5.63	7615	65	44	16	28	$0.035	$53	$13
2031	1,510	5.70	7615	66	43	15	28	$0.035	$53	$12
2032	1,503	5.45	7615	62	40	13	27	$0.035	$53	$11
2033	1,495	5.63	7615	64	39	12	27	$0.035	$52	$10
2034	1,488	5.79	7615	66	39	11	28	$0.035	$52	$9
2035	1,480	6.03	7615	68	39	11	28	$0.035	$52	$8
2036	1,473	6.30	7615	71	39	10	29	$0.035	$52	$7
2037	1,465	6.53	7615	73	38	9	29	$0.035	$51	$7
2038	1,458	6.79	7615	75	38	9	30	$0.035	$51	$6
2039	1,451	7.29	7615	81	39	8	31	$0.035	$51	$5
2040	1,443	7.71	7615	85	40	8	32	$0.035	$51	$5
2041	0	8.10	7615	0	0	0	0	$0.035	$0	$0
2042	0	8.51	7615	0	0	0	0	$0.035	$0	$0
2043	0	8.94	7615	0	0	0	0	$0.035	$0	$0
2044	0	9.39	7615	0	0	0	0	$0.035	$0	$0
2045	0	9.87	7615	0	0	0	0	$0.035	$0	$0
							$537			$537

Appendix 6 – ELCC

Importance of Solar Rating Convention

The ELCC for the Base Case was calculated as 54.4%. It is important to understand that this result reflects the solar capacity rating convention used in the report, namely, AC capacity with losses. While the solar industry has standard rating conventions for modules and inverters, it does not for as-built systems. Among the ratings used for system capacity are:

- DC (the DC module rating at standard test conditions)
- PTC (the DC module rating at "PVUSA Test Conditions")
- California Energy Commission, or CEC (the PTC rating times the load-weighted inverter efficiency)
- AC nameplate (the maximum power output of the inverter
- AC with losses (the CEC rating, less system losses)

The selection of rating convention is arbitrary, but must be used consistently. As shown in Table 36, the same Base Case Time Series (AC electrical energy delivered by the fleet to the grid) is used to show how two different rating conventions yield the same end result, but that intermediate results may differ.

For example, the 1 kW AC rating (with losses) is equivalent to a 1.30 kW DC rating. The fleet time series is identical, and yields the same effective capacity of 0.544 kW. However, when expressing ELCC as a percentage of rating, the result is an ELCC of 54.4% and 41.9% for the AC method and DC method, respectively. Similarly, the capacity factor (annual energy as compared to a constant output of full rated capacity) yields 18.6% and 14.3%, despite the fact that the annual energy production is the same. Finally, the table shows an illustration of how first capacity year capacity value yields the same value. These values were not included in the study results and are provided only as an illustration of how rating convention is an arbitrary selection.

Table 36. AC versus DC Rating Conventions

	AC Rating Convention	DC Rating Convention
Marginal PV Production Profile	Base Case Time Series	Base Case Time Series
Resource Rating	1 kW AC	1 /0.77 = 1.30 kW DC
ELCC	0.544 kW / 1 kW = 54.4%	0.544 kW / 1.30 kW = 41.9%
Annual Energy	1628 kWh / 1 kW = 1628 kWh/kW (18.6% capacity factor)	1628 kWh / 1.30 kW = 1252 kWh/kW (14.3% capacity factor)
First Year Capacity Value (Illustrative)	\$10/kW-mo x 12 mo/yr x 1 kW (dispatchable) x 54.4% (effective) ÷ 1628 kWh/kW = \$0.040 per kWh	\$10/kW-mo x 12 mo/yr x 1 kW (dispatchable) x 41.9% (effective) ÷ 1252 kWh/kW = \$0.040 per kWh

Differences with Seasonal Claimed Capacity

As described in the methodology section, the calculation of ELCC was based on the median fleet output over the top 100 hours in each of the three years of the Load Analysis Period. This method was selected instead of basing it on the ISO New England rules for Seasonal Claimed Capacity in order to perform the anticipated High Penetration scenario.

Specifically, the Seasonal Claimed Capacity is based on the defined intermittent reliability hours:

- Summer: Median output HE 14:00 to 18:00 (June to Sept)
- Winter: Median output HE 18:00 to 19:00 (Oct to May)

Therefore, the SCC is independent of penetration level. It is well understood that the effective capacity of solar will decline with penetration as load shifts to non-solar hours, yet this effect would not be indicated had these defined periods been the basis of the ELCC calculations.

The time series for the Base Case fleet results in the following:

- Summer median output is 18.4%
- Winter median output is 0%
- Annual weighted SCC is (18.4% x 4 months + 0% x 8 months) / 12 months = 6.1%

Thus, the SCC method would have yielded a result of 6.1% versus the 54.4% used in the study. This result would have been applied to the capacity-related economic benefits, significantly reducing their value.

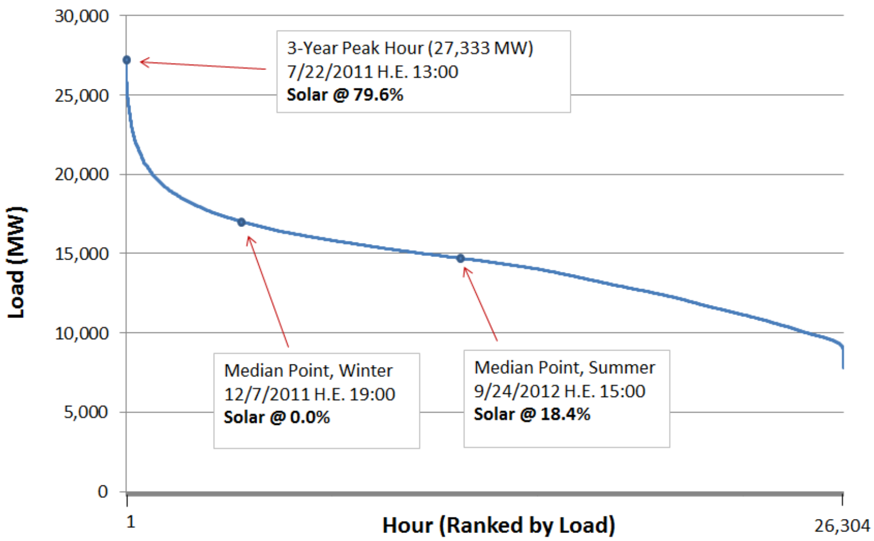
To determine why the discrepancy is so large, an additional analysis was performed, considering only the 10 highest peak load hours over the three year period. The results are shown in Table 37. The top 10 hours are found in two days: July 22, 2011 and July 19, 2013. The average output during these 10 hours is 73.5% of AC rating. This is significantly higher than the analysis based on the top 100 hours, and it is of interest to note that the fleet output during the highest, most critical hour of the three year period was 79.6% of rated output.

Table 37. Base Fleet production during highest 10 hours, 2011-2013.

Hour Ending	Load (MW)	Base Fleet
7/22/2011 13:00	27,333	79.6%
7/22/2011 12:00	27,283	85.0%
7/22/2011 14:00	27,262	69.3%
7/22/2011 11:00	27,181	85.0%
7/22/2011 15:00	27,082	55.0%
7/19/2013 15:00	26,919	54.8%
7/19/2013 14:00	26,913	68.9%
7/19/2013 13:00	26,910	77.2%
7/19/2013 12:00	26,886	79.3%
7/22/2011 10:00	26,880	80.5%

A further investigation indicates that the median output over the summer season intermittent reliability hours occurs on September 24, 2012, in the hour ending 15:00. The fleet output was 18.4% as indicated previously. However, as shown in Figure 27, the ISO-NE load during that hour was only 14,733 MW, when the control area load was only about half of its maximum of 27,333 MW. Median output during the winter hours occurs at 12/7/2011 at hour ending 19:00, when load was 16,974 MW. These two points define the effective capacity using the SCC method, despite the fact that they do not represent peak load hours.

Figure 27. Selected Base Case fleet output on ISO-NE load duration curve.



Another way to view these results is that the “capacity value” could have been broken into two separate components: a “market value” showing the value of solar that would result from participation in the forward capacity market, and a “ratepayer avoided cost” value representing the remaining reduction in installed capacity requirement (ICR) that results from the reduction in peak load in New England.

Appendix 7 – Sensitivity Cases

Cost and benefit calculations have been performed for selected sensitivity runs as follows:

	Base Case	Additional Cases
Fleet Production Profile	Base Case profile	• Maximum Energy Production • Maximum Capacity • Residential Proxy • Non-Residential Proxy See description below.
PV Life	25 years	20 and 30 years
PV Degradation Rate	0.5% per year	0.2% per year, 0.8% per year
PV Penetration Level	Current penetration (approximately 10 MW)	Penetration level corresponding to annual PV production at 5% of energy (approximately 300 MW) with no load growth. See description below.
Location	Distribution system	Transmission system (“Utility Scale”). Results will be recalculated without transmission capital cost savings and without T&D loss savings.

PV Fleet Production Profiles

Five different PV fleet production profiles were developed. Each results in a different value calculation, and thus provides insight into the relationship between design configuration and value. The five sets are:

1. Baseline Fleet. A blend of all PV resources representing the State’s expected geographical and design orientation diversity across all DG resources, regardless of customer class. The method for developing this data is described in the Hourly PV Fleet Production section.

2. Maximum Energy Production. A blend of resources representing the State’s geographical diversity, but all having the same orientation selected for maximum annual energy production.

These data were developed by running an initial test for a single location in Portland at multiple orientations, selecting the orientation with maximum energy over the load analysis period (e.g., South-20) and running this configuration (only) at all zip codes, weighted by population.

3. Maximum Capacity. A blend of resources representing the State's geographical diversity, but all having the same orientation selected for maximum ELCC. These data were developed by running an initial test for a single location in Portland at multiple orientations, selecting the orientation with maximum ELCC over the load analysis period (e.g., West-30) and running this configuration (only) at all zip codes, weighted by population.

4. Residential Proxy. A blend of all PV resources representing the State's expected geographical and design orientation diversity across all residential DG resources. These data were developed in a manner similar to the Baseline Fleet, but based on a configuration analysis for residential systems in upstate New York. These systems are expected to have similar roof constraints as systems in Maine.

5. Non-Residential Proxy. A blend of all PV resources representing the State's expected geographical and design orientation diversity across all residential DG resources. These data were developed in a manner similar to the Baseline Fleet, but based on a configuration analysis for non-residential systems 10 to 500 kW in New York, Connecticut, and Massachusetts.

PV Penetration Level

As PV penetration increases, the load shape will change accordingly, potentially shifting peak times to non-solar hours. This results in lower ELCC and lower avoided costs that are capacity related. The sensitivity was performed by scaling the PV Fleet Production Profile such that the resulting solar energy over the Load Analysis Period is 5 percent of the Maine annual energy load (roughly 300 MW of distributed solar).

Results

Sensitivity results are shown in the following figures.

Figure 28. Fleet Production Profile Sensitivity (CMP)

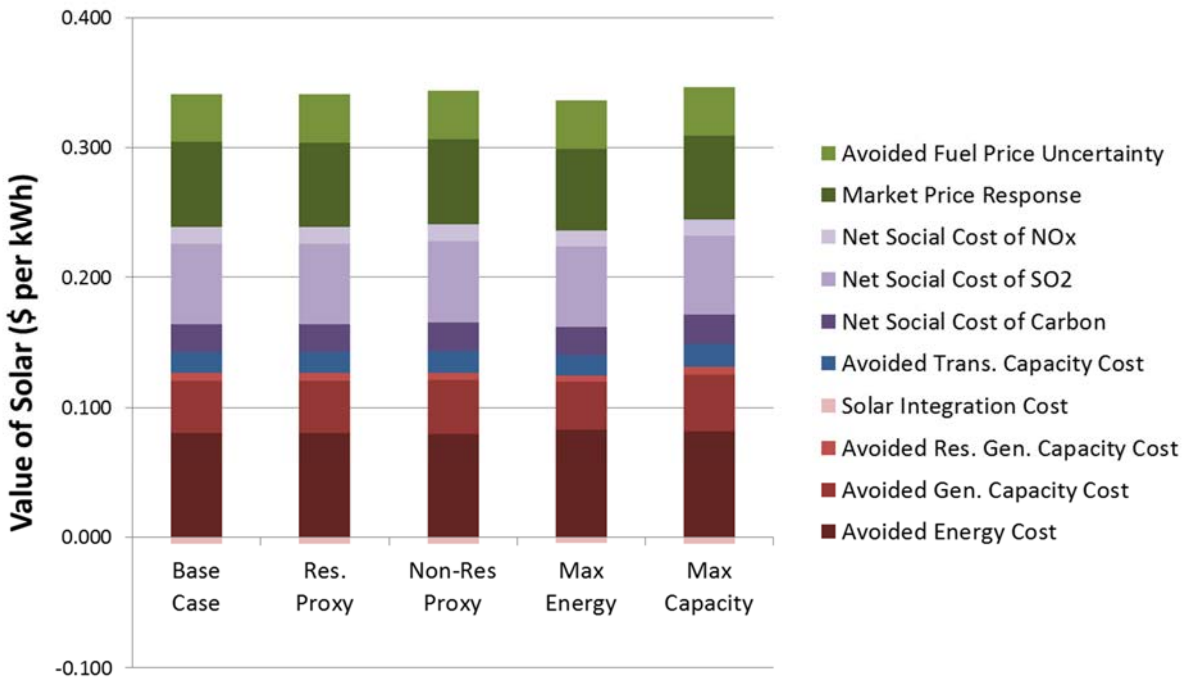


Figure 29. PV Life Sensitivity (CMP)

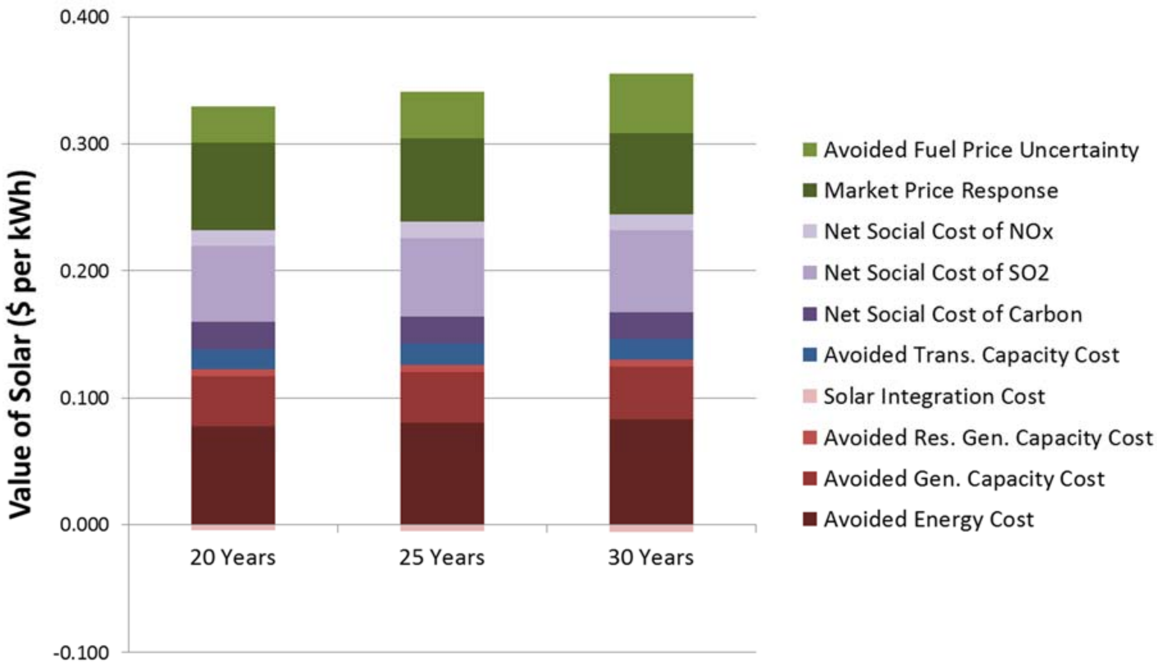


Figure 30. Degradation Sensitivity (CMP)

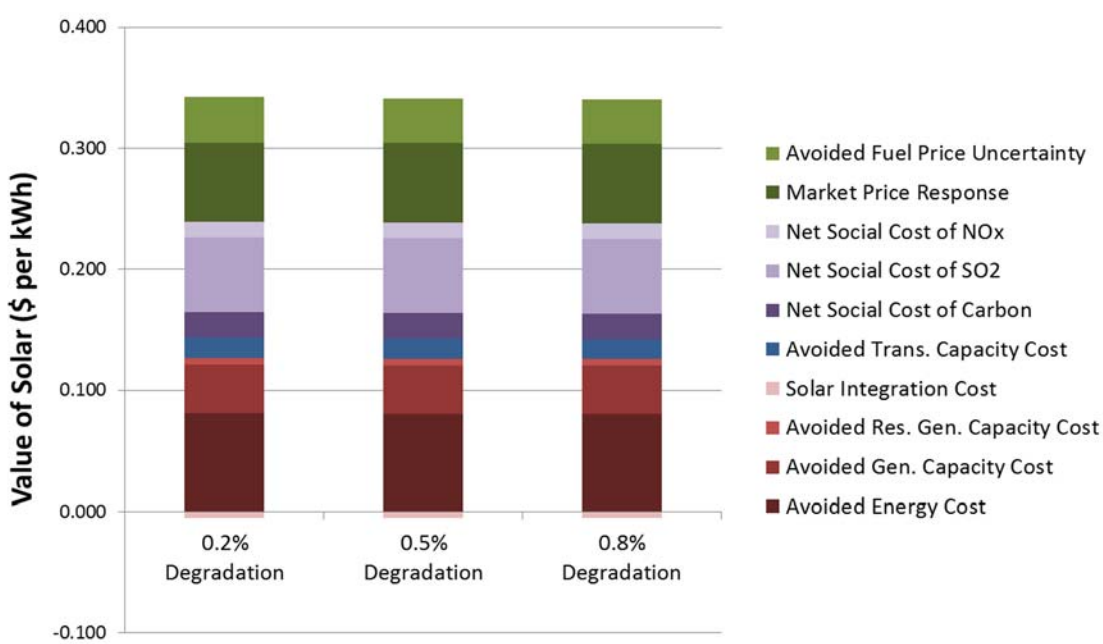


Figure 31. High Penetration Sensitivity (CMP)

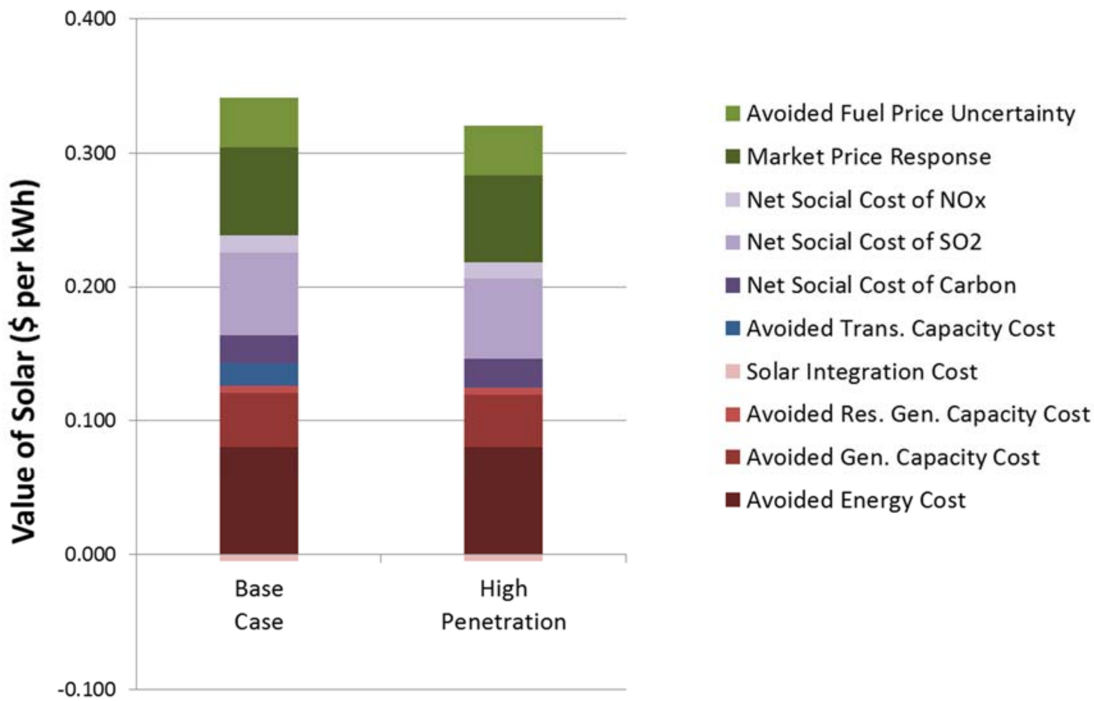


Figure 32. Transmission-connected (“Utility Scale”) Sensitivity