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Initial Update of the Maine PUC's Value of Solar Study

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This memorandum reports on our initial update to the analysis in the Maine Public Utilities Commission's 2015 *Maine Distributed Solar Valuation Study* (Maine VOS Study), published March 1, 2015. That study found that distributed solar in Central Maine Power's service territory would have a 25-year levelized value of $0.337 per kWh, including $0.138 per kWh of avoided market costs and $0.199 per kWh of societal benefits, as summarized in Figure ES-2 of the report.

Figure ES- 2. 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	

Generally, our update finds only minor changes to the values presented in the Maine VOS Study, with the exception of a significant decline in the market price response benefit. This is not surprising, given that the study was completed just 14 months ago, in May 2015. Since the study was completed, lower natural gas prices have reduced avoided energy costs, but these have been offset by higher ISO-NE generation capacity prices and higher avoided capacity costs for regional transmission. **Figure 1** below presents the results of our update.

In one change from how the results for the Maine VOS Study were reported, we have included the market price response and the avoided fuel price uncertainty benefits in the category of "avoided market costs." These benefits will provide lower energy market costs for Maine ratepayers in the future, and thus in our opinion they should be included with the other direct benefits of distributed solar as avoided market costs.

Figure 1: *Updated Maine VOS Results*

		Gross Value A ($/kWh)	x	Load Match Factor B (%)	x	Loss Savings Factor (1-C) (%)	=	Distribted PV Value D ($/kWh)	
Energy Supply	Avoided Energy Cost	$0.062				6.2%		$0.066	
	Avoided Gen. Capacity Cost	$0.085		54.4%		9.3%		$0.050	
	Avoided Res. Gen. Capacity Cost	$0.014		54.4%		9.3%		$0.009	
	Avoided NG Pipeline Cost								
	Solar Integration Cost	($0.005)						($0.005)	
Transmission Delivery Service	Avoided Trans. Capacity Cost	$0.072		23.9%		9.3%		$0.019	Avoided Market Costs $0.176
Distribution Delivery Service	Avoided Dist. Capacity Cost							$0.005	
	Voltage Regulation								
Other	Market Price Response	$0.001				6.2%		$0.001	
	Avoided Fuel Price Uncertainty	$0.029				6.2%		$0.030	
Environmental	Net Social Cost of Carbon	$0.020				6.2%		$0.021	
	Net Social Cost of SO_2	$0.058				6.2%		$0.062	Societal Benefits $0.096
	Net Social Cost of NO_x	$0.012				6.2%		$0.013	
						Total VOS:		$0.272	

The Maine VOS Study is notable for the detail and clarity with which its methodology is presented. As a result, it is relatively straightforward to update many of the key drivers of its results. However, the detailed spreadsheet model for the Maine VOS Study is not publicly available,[1] so we have reproduced that model, albeit with less detail in certain areas such as the modeling of the generation from an assumed PV fleet in Maine. We discuss below the changes that we have made to the assumptions and analysis used in the Maine VOS Study.

Avoided energy costs. We have updated the ISO-NE locational marginal price (LMP) data used to calculate avoided energy costs to include LMP data through 2015, and we have updated the long-term natural gas price forecasts from the NYMEX forward market and from the Energy Information Administration (EIA) used to escalate the PV-weighted avoided energy costs from 2015 to future years.[2] This results in lower avoided energy costs, as natural gas price expectations have declined over the past year.[3]

Avoided generation capacity costs. Our projection of avoided generation capacity costs follows the methodology used in the Maine VOS Study, but includes the results from ISO-New England's (ISO-NE) forward capacity market (FCM) Auctions 9 and 10,[4] plus the projection for future avoided capacity costs included in the most recent regional avoided cost forecast, *Avoided Energy Supply Costs in New England: 2015 Report (2015 AESC)*.[5] This forecast includes appreciably higher long-term avoided generation capacity costs than the prior *2013 AESC* forecast used in the Maine VOS Study.

Avoided transmission capacity costs. We have updated the calculation of avoided transmission costs to use ISO-NE's reported Regional Network Load (RNL) transmission costs for Maine, for the year ending May 2016.[6] There was a significant increase in these costs which took effect on June 1, 2015. As a result, the updated avoided transmission capacity costs are higher than those used in the Maine VOS Study. We escalate these costs at 2% per year, although we observe that this is a conservative assumption, because in recent years these costs

[1] Per the study's authors at Clean Power Research.

[2] This approach to escalating solar-weighted LMPs follows the template on page 78 of the Maine VOS Study. We used NYMEX Henry Hub forward market prices from July 1, 2016 and the long-run gas price forecast from EIA's *Annual Energy Outlook 2016*.

[3] We did not attempt to duplicate the detailed modeling of a hypothetical fleet of PV resources in Maine that is in the Maine VOS Study. This modeling is used to calculate the solar-weighted average LMP price, and to determine the "load match factors" used in calculating avoided generation and transmission capacity costs. Instead, we used a simulation of a representative PV system in Portland, Maine whose output (1,679 kWh per kW-AC) and load match factor (54.4%) are very close or identical to the corresponding values for the PV fleet modeled in the Maine VOS Study (1,667 kWh/kW-AC [Base Case] and 54.4%, respectively). See Maine VOS Study, at pages 74 and 77.

[4] See http://www.iso-ne.com/static-assets/documents/2016/02/fca_10_result_report.pdf. In the Maine VOS Study, the avoided generation capacity costs used the results through FCM auction 8, plus a Synapse forecast of future capacity market prices that escalates a 2020 price of about $10 per kW-month with inflation. See Maine VOS Study, at pages 30, 79, and Figure 22.

[5] See *2015 AESC*, at Appendix B., Tables One and Two for Maine. This report is available at https://www9.nationalgridus.com/non_html/eer/ne/AESC2015%20merged%20report.pdf.

[6] See ISO-New England, *Monthly Regional Network Load Cost Report* (May 2016), at Table 8-1. Available at http://www.iso-ne.com/markets-operations/market-performance/load-costs.

have been rising faster than the general inflation rate.

Market price response. We have incorporated data from the *2015 AESC* on the market price reductions that will result from the on-site solar distributed generation in Maine that serves load directly. This market benefit is also known as the demand reduction induced price effect, or DRIPE. The DRIPE impacts in Maine that are forecasted in the *2015 AESC* are significantly lower than those calculated in the *2013 AESC* (which were used in the Maine VOS Study), as a result of significant changes in the approach to the DRIPE calculations used in the *2015 AESC.*[7] For example, the *2015 AESC* assumes (1) a much shorter duration for energy DRIPE impacts and (2) zero capacity DRIPE as a result of an assumed near-term need for new capacity in New England.

Avoided fuel price uncertainty. We assume that the value of avoided fuel price uncertainty scales with the overall forecast of natural gas prices. As a result, we have adjusted this avoided market cost component downward based on the percentage change in the revised natural gas price forecast.

Avoided distribution capacity costs. Distributed solar generation can reduce peak loads on distribution circuits, and thus avoid or delay the need to upgrade or re-configure the circuit if it is approaching capacity. However, circuits and substations on the distribution system can peak at different times than the system as a whole, which complicates the assessment of the extent to which solar DG can avoid or defer distribution capacity upgrades. As DG penetration grows, and a deeper understanding is gained of the impacts of DG on distribution circuit loadings, we anticipate that utility distribution planners will integrate existing and expected DG capacity into their planning, enabling DG to avoid or defer distribution capacity costs. A comparable evolution has occurred over the last several decades, as the long-term impacts of energy efficiency and demand response programs are now incorporated into utilities' capacity expansion plans, and it is generally recognized that these demand-side programs can help to manage demand growth even though the specific locations where these resources will be installed are difficult to predict.

The Maine VOS study suggests that avoided distribution capacity costs can be estimated from studies of these avoided costs in other states, in the absence of specific analyses that focus on the Maine utilities. The available studies which quantify the distribution capacity costs avoided by solar generation generally have calculated relatively modest values. **Table 2** below lists some of the studies which have calculated avoided distribution capacity costs, including the values presented. Crossborder's study in Colorado, as well as the most recent CPUC-E3 studies in California, have used the correlation between solar output and distribution substation peaks to calculate load match factors for distribution capacity, which is then applied to an estimate of marginal distribution capacity costs derived from utility distribution investment plans. Based on these most recent studies, a reasonable, conservative value for avoided distribution capacity costs is 0.5 cents per kWh, which we have used in this update.

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[7] See *2015 AESC*, at pages 1-5 and 1-16 to 1-17.

Table 2: *Studies of Avoided Distribution Capacity Costs*[8]

State / Study / Date	Avoided Distribution Capacity Costs *(c/kWh)*	*Source*
AZ / R.W. Beck / 2009	0 to 0.31	*Fig. 6-2 at 6-14.*
PA-NJ / Clean Power / 2012	0.1 to 0.8	*Table 4*
AZ / Crossborder / 2013	0.2	*Table 1, at 2.*
AZ / SAIC / 2013	0	*pp. 2-10 to 2-12. No savings unless solar is targeted to circuits that are close to capacity.*
CA / CPUC-E3 / 2013[9]	0.6	*Includes marginal subtransmission and distribution capacity costs. Based on correlation of distribution substation peaks to solar peaks. See Appendix C.*
CO / Xcel Energy / 2013	0.05	*Table 1, at v and 27-36.*
CO / Crossborder Energy critique of Xcel Energy / 2013[10]	0.6	*Based on Xcel's marginal distribution capacity costs and the correlation of distribution substation peaks to solar peaks. See pages 9-11 and Table 5.*
CA / CPUC-E3 / Public Tool Model / 2015[11]	2.9	*Based on the marginal distribution and sub-transmission capacity costs for the California electric utilities and the correlation of distribution substation peaks to solar peaks.*

Conclusion. Figure 1 shows our updated Maine VOS results, a 25-year levelized value of $0.272 per kWh, including $0.176 per kWh of avoided market costs and $0.096 per kWh of societal benefits.

[8] All of these studies except for the Crossborder Colorado critique and the 2013 and 2015 CPUC-E3 studies are referenced and discussed in the Rocky Mountain Institute's meta-analysis of distributed generation benefit-cost studies. See Rocky Mountain Institute, *A Review of Solar PV Benefit and Cost Studies* (July 2013), at page 31, available at http://www.rmi.org/Knowledge-Center/Library/2013-13_eLabDERCostValue.

[9] The 2013 CPUC-E3 net metering cost-benefit study is available at http://www.cpuc.ca.gov/general.aspx?id=3800.

[10] See R. Thomas Beach and Patrick G. McGuire, *Benefits and Costs of Solar Distributed Generation for the Public Service Company of Colorado: A Critique of PSCo's Distributed Solar Generation Study.* Available at http://www.oursolarrights.org/files/5513/8662/3174/Crossborder_Study_of_the_Benefits_of_Distributed_Solar_Generation_for_PSCo.pdf.

[11] Based on the marginal subtransmission and distribution costs of the California electric utilities and the CPUC-E3's Public Tool model of the benefits and cost of net metering in California. The Public Tool is described and is available at http://www.cpuc.ca.gov/General.aspx?id=11285. Assumes the use of 100% of the utilities' marginal subtransmission and distribution costs.