Maine Public Utilities Commission

Maine Distributed Solar Valuation Study

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Maine Public Utilities Commission

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Note on Edition

This edition is an updated and revised version of the March 1, 2015 report delivered to the Maine Legislature and incorporates changes and clarifications further described in the March 25, 2015 addendum.

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Maine Distributed Solar Valuation Study

Executive Summary

Background

During its 2014 session, the Maine Legislature enacted an Act to Support Solar Energy Development in Maine. P.L Chapter 562 (April 24, 2014) (codified at 35-A M.R.S. §§ 3471-3473) ("Act"). Section 1 of the Act contains the Legislative finding that it is in the public interest is to develop renewable energy resources, including solar energy, in a manner that protects and improves the health and well-being of the citizens and natural environment of the State while also providing economic benefits to communities, ratepayers and the overall economy of the State.

Section 2 of the Act requires the Public Utilities Commission (Commission) to determine the value of distributed solar energy generation in the State, evaluate implementation options, and to deliver a report to the Legislature. To support this work, the Commission engaged a project team comprising Clean Power Research (Napa, California), Sustainable Energy Advantage (Framingham, Massachusetts), Pace Energy and Climate Center at the Pace Law School (White Plains, New York), and Dr. Richard Perez (Albany, New York).

Under the project, the team developed the methodology under a Commission-run stakeholder review process, conducted a valuation on distributed solar for three utility territories, and developed a summary of implementation options for increasing deployment of distributed solar generation in the State.

The report includes three volumes which accompany this Executive Summary:

Volume I	Methodology
Volume II	Valuation Results
Volume III	Implementation Options

Volume I – Methodology

The methodology developed in Volume I was designed to quantify the benefits and costs of the gross energy produced by a photovoltaic (PV) system, as if it were delivered to the grid through its own meter, i.e., prior to serving any local load. Variants of this methodology could be used to determine the value of energy exported to the grid after netting local load (or even generation technologies other than solar), but these would require the development of generation/load profiles that are not included in this methodology.

Guided by the Act and a stakeholder-driven process, the methodology provides for the calculation of the costs and benefits of distributed solar generation for each of the selected components shown in Table ES- 1. The basis for the cost calculations is also shown.

Table ES- 1. Benefit/Cost Bases

Component	Benefit/Cost Basis
Avoided Energy Cost	Hourly avoided wholesale market procurements, based on ISO New England day ahead locational marginal prices for the Maine Load Zone.
Avoided Generation Capacity and Reserve Capacity Costs	ISO New England Forward Capacity Market (FCM) auction clearing prices, followed by forecasted capacity prices by the ISO's consultant. For reserves, the ISO's reserve planning margin is applied.
Avoided NG Pipeline Costs	Not included, but left as a future placeholder if the cost of building future pipeline capacity is built into electricity prices.
Solar Integration Costs	Operating reserves required to handle fluctuations in solar output, based on the New England Wind Integration Study (NEWIS) results.
Avoided Transmission Capacity Cost	ISO New England Regional Network Service (RNS) cost reductions caused by coincident solar peak load reduction.
Avoided Distribution Capacity Cost	Not included, but left as a future placeholder if the peak distribution loads begin to grow (requiring new capacity).
Voltage Regulation	Not included, but left as a future placeholder if

	new interconnections standards come into existence allowing inverters to control voltage and provide voltage ride-through to support the grid.
Net Social Cost of Carbon, SO2, and NOx	EPA estimates of social costs, reduced by compliance costs embedded in wholesale electricity prices.
Market Price Response	The temporary reduction in electricity and capacity prices resulting from reduced demand, based on the Avoided Energy Supply Costs in New England (AESC) study.
Avoided Fuel Price Uncertainty	The cost to eliminate long term price uncertainty in natural gas fuel displaced by solar.

Volume II - Valuation Results

First Year Value

Figure ES- 1 presents the overall value results from Volume II for the Central Maine Power (CMP) Base Case in the first year using the stakeholder reviewed methodology of Volume I. Avoided market costs—including Energy Supply, Transmission Delivery, and Distribution Delivery—are $0.09 per kWh. Additional societal benefits are estimated to be $0.092 per kWh. Avoided NG Pipeline Cost, Avoided Distribution Capacity Cost, and Voltage Regulation are included as placeholders for future evaluations should conditions change that would warrant inclusion.

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 collected from Maine electric customers.

Figure ES- 1. CMP Distributed Value – First Year ($ per kWh)

First Year

		Distributed Value ($/kWh)	
Energy Supply	Avoided Energy Cost	$0.061	Avoided Market Costs $0.090
	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	Societal Benefits $0.092
	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	

Environmental Results

The above results indicate a very high environmental value relative to other solar valuation studies. In particular, the Net Social Cost of SO2 is 28% of the total value (market plus societal benefits). The study methodology was based on a three year historical calculation of marginal emissions rates. However, emissions of SO2 and NOx rates are expected to decline in the coming years. If the fuel type were assumed to be only oil and natural gas (FTA marginal emissions rates as described in the Displaced Pollutants section), the displaced emissions and the net social costs shown above would be reduced to 8% and 20% of the values calculated here for SO2 and NOx, respectively.

Long Term Value

Figure ES- 2 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. The selection 25 years is based on the assumed useful service life of a typical solar PV system.

It is important to note that Figure ES-2 does not identify who the benefits and costs accrue to. For example, avoided energy cost is calculated based on avoided wholesale energy purchases, but this value may involve a series of transactions between the solar customer, the distribution utility, and the energy market participants.

The value shown in Table ES-2 represents a longer term projection of the levelized value of a solar PV system over a 25 year horizon. It is meant to be illustrative and not as a standalone value apart from First Year Value descriptions.

The societal benefits, such as the net Social Cost of SO_2, are external to what present market mechanics monetize; as such they do not monetarily accrue to any market participants (distribution utility, transmission provider, third party generators, etc.). It is left as a policy decision to determine whether these values are relevant and whether to include them in tariff design, incentives, and other structures.

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	

Gross Values represent the value of perfectly dispatchable, centralized resources. These are adjusted using

- Load Match Factors to account for the non-dispatchability of solar; and
- Loss Savings Factors to account for the benefit of avoiding energy losses in the transmission and distribution systems.

The load match factor for generation capacity (54%) is based on the output of solar during the top 100 load hours per year. The load match factor for Avoided Transmission Capacity Cost (23.9%) is derived from average monthly reductions in peak transmission demand.

The Distributed PV value is calculated for each benefit and cost category, and these are summed. The result is the 25-year levelized value, meaning the equivalent constant value that could be applied over

25 years that would be equivalent to the combined benefits of avoided market costs and societal benefits.

First Year results for all three utility service territories, including Emera Maine's Bangor Hydro District (BHD) and Maine Public District (MPD), are shown in Figure ES- 3. The results are 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 ES- 3. Base Case Results for CMP, BHD, and MPD – First Year

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

Volume III - Implementation Options

Objective

The Act sought information on options for distributed solar energy implementation. Volume III of this report provides an analysis of options for increasing investment in or deployment of distributed solar generation, with an emphasis on those options used in ten states with similarities to Maine in market structure (deregulated) and economic opportunity (driven by insolation, land use, electricity prices, etc.). It also provides general guidance to help the Legislature consider which options, approaches or models may be appropriate for Maine, considering the State's utility market structures.

Solar Implementation Options

Volume III includes a thorough list of solar implementation options in widespread use. The range of implementation options are organized into four major categories:

- **Instruments Used to Incentivize Solar -** Incentives commonly used as vehicles to incentivize distributed solar PV include a suite of implementation options aimed at changing market or economic decision making by (i) creating market demand, (ii) removing financing barriers, and/or (iii) lowering installation costs for solar PV.

- **Financing Enabling Policies -** Financing enabling policies enhance the accessibility of financing, lower financing transactions costs, open up access to lower-cost forms of financing, and otherwise lower the entry barrier to solar investment and enable a broader range of players to participate in the solar market.

- **Rules, Regulations and Rate Design –** Rules, regulations and rate design at all levels of government ensure legal access to the solar market, regulate the economics of solar PV and provide technical support to solar PV deployment.

- **Industry Support -** Industry support approaches are often paired with other implementation strategies to accelerate solar deployment. By incentivizing in-state solar investment, many industry support approaches are also designed to stimulate local job creation and foster state economic growth.

Table ES- 2Table ES- 5 provide an overview of implementation options. Options in shaded rows are commonly-used implementation options but of less potential interest for legislative consideration, and are only discussed briefly in Section 0 of Volume III. The other implementation options are more fully characterized and evaluated. Where applicable, Volume III highlights implementation examples in the five New England States (Connecticut, Massachusetts New Hampshire, Rhode Island and Vermont), New York, and four states (Delaware, Maryland, New Jersey, and Pennsylvania) within the PJM territory. The authors underscore important observations from implementation experiences in these states, as well as notable variations. Volume III also includes a summary of the identified solar implementation options that have been adopted in each state.

Table ES- 2. Summary of Solar Implementation Option: "Instruments Used to Incentivize Solar"

Subcategory	Implementation Examples	Description
Direct Financial, Up-front Incentives	Grants, Rebates, or Buy-Downs	Capacity-denominated (i.e., $/kW) incentives designed to reduce up-front cost of PV installations; typically targeted to small- and medium-scale customers
Direct Financial, Performance-Based Incentives (PBIs)	Feed-In-Tariffs, Standard Offer PBI Contracts or Tariffs, or PBIs	Pre-determined, fixed energy-denominated (i.e., $/kWh) incentives for solar energy production designed to provide predictable revenue stream; typically targeted to small- and medium-scale customers
	Competitive Long-Term PPAs	Long-term (10 – 25 years) PPAs for RECs, energy and/or capacity solicited through a competitive process; typically targeted to larger, more sophisticated players
	Long-Term Value of Solar Tariffs	Mechanism crediting solar generation at a rate determined by a value of solar analysis
	Technology-Specific "Avoided Costs"	Incentive rates set at the avoided-costs of a technology
Indirect Financial Incentives	Emissions Markets	Market-based emission cap-and-trade programs; usually regional scale
Expenditure-Based Tax Incentives	Investment Tax Credits	Capacity-denominated tax incentives (i.e., $/kW); Federal ITC is the most common form
Production Tax Incentives	Production Tax Credits	Electricity-production-based tax incentives (i.e., $/kWh)
Demand-Pull/Solar Minimum Purchase Mandates	Renewable Portfolio Standards (RPS)	Mandate requiring certain % of electric utilities' annual retail sales be met with renewable generation
	Solar Set-Asides in RPS (SREC Market)	Mandate creating a separate tier or requiring certain portion of RPS to be met with solar
Net Metering	Net Metering Crediting Mechanism	Mechanism used for utilities to credit customers for excess on-site generation
	Virtual NM Crediting Mechanism	Subset of net metering that enables the aggregation of net metering accounts/facilities
	Community-Shared Solar	Subset of virtual net metering allowing multiple customers to share ownership interest in a single remote net metered facility

Table ES- 3. Summary of Solar Implementation Option: "Finance Enabling Policies"

Implementation Examples	Description
Solar Loan Programs	A broad spectrum of loan products supported by private sector financing or utilities
On-Bill Financing	Long-term, low interest loans where repayments are made through utility bills
PACE Financing	Long-term, low interest loans where payments are made through property taxes and are tied to hosting sites instead of system owners
Green Bank – Institutions and Suite of Other Programs	State-chartered institution offering a suite of programs and financing products; leverages and recycles public funding to stimulate growth of private financing markets for solar
Utility Ownership	Policies enabling T&D utilities to own generation assets in deregulated markets
Solar Lease and/or Third-Party Ownership Enabling Policies or Eligibility in Other Policies	Policies allowing a private developer to (i) install and own a PV system hosted by a property owner, then selling the power to the property owner through PPA; or (ii) lease PV panels to customers

Table ES- 4. Summary of Solar Implementation Option: "Rules, Regulations and Rate Design"

Subcategory	Implementation Examples	Description
Removing Institutional Barriers	Interconnection Standards	Regulations standardizing the requirements of integrating solar PV to the grid
	Solar Access Laws	Rules protecting customers' access to sunlight and solar development rights
	Business Formation/Financing Laws	Policies authorizing certain types of business models or market structures designed to lower the entry barrier and expand access to the solar market
	Permitting Simplification, Other "Soft-Cost Reduction" Strategies	A suite of strategies designed to reduce the non-equipment costs associated with various stages of solar PV development
Building Codes	Solar-Ready Building Standards, Zero-	Various building standards that (i) regulate orientation, shading, and other siting- and

	Energy Capable Home Standards	construction-related criteria; or (ii) support "plug-and-play" PV system configurations
Tax	Property Tax Exemption or Special Rate	Property tax relief to property owners installing solar PV
	Sales Tax Exemption	Tax relief exempting system owners from paying sales taxes for PV system equipment
	Property Tax/Payment in lieu of taxes (PILOT) Standardization or Simplification	State policies designed to limit community-by-community variations in property tax and PILOT rules; designed primarily to remove uncertainty
Grid Modernization	Policies Enabling Microgrids, Smart-Grid and Other DG-Friendly Grid Architecture	Policies designed to promote installations of DG-friendly technologies and grid architecture; aim to ease interconnection and advance implementation of solar PV
Rate Design	Time-Varying Rates, Rate Design, Fixed Charges and Minimum Bills	Cost-based utility rate design or rate structures designed to provide a correct or supportive price signal for the installation and operation of solar generation facilities

Table ES- 5. Summary of Solar Implementation Option: "Industry Support"

Implementation Examples	Description
Incentives for Companies, Technology Development, or Economic Development	Funding mechanisms designed to provide incentives for in-state solar businesses; allocated from the state budget, RPS alternative compliance payments, RGGI proceeds and/or public good funds
Local Content Bonus Or Mandate	Incentives or requirements that give preference to projects supporting in-state investment
Customer Acquisition Cost Reduction	Strategies leveraging scale economies or other measures to increase solar participation at a lower cost
Outreach/Education/Public Information/Voluntary Market Encouragement	Strategies designed to increase customer awareness of solar technology, voluntary and compliance solar markets, and solar funding and financing options
Public Sector Leadership and Demonstration	State or local initiatives, such as demo projects on public properties or statewide PV goals
Creation of Public Good Funds to Support Solar Programs/Policies	Policies establishing funds collected from ratepayers through utility bill surcharges; designed to provide long-term funding for solar incentive programs
Installer/Inspector Training and Certification	Training and certification programs designed to build a qualified local solar workforce

Solar Implementation in Maine

Section 2 of Volume III summarizes the current suite of implementation mechanisms applicable to solar PV in Maine. Maine's solar implementation mechanisms include a range of approaches that are broadly applicable to various renewable resources and not specific to solar. Implementation mechanisms currently used to support renewable energy implementation in Maine include net metering, shared ownership net metering, Renewable Portfolio Standard, community-based renewable incentives, long-term contracts, time-of-use rates, and interconnection standards.

Solar Implementation in Other States: Key Themes and Lessons Learned

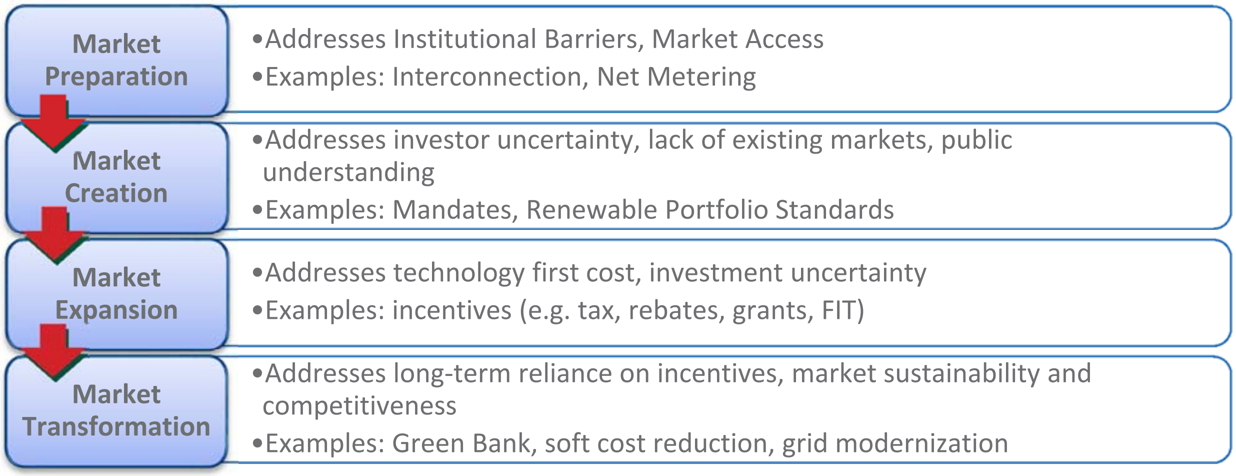
Section 3 of Volume III identifies and describes solar implementation options used in other states, with particular emphasis on the ten northeastern states identified above. The other states studied in Volume III have established a variety ofsolar-specific implementation options specifically targeted to grow solar penetration. Based on our analysis and evaluation of solar implementation experiences in these states, we identify four key themes or lessons learned from these other states that may be considered appropriate within Maine's context.

- A comprehensive strategy to support solar PV has proven effective at increasing solar PV penetration. In all ten states studied here, state policymakers implemented a combination of implementation options simultaneously to maximize the support available for, and reduce barriers to, diverse solar deployment. The Legislature may wish to consider combining various policies, programs, rules, regulations, incentives and industry support strategies to achieve multiple implementation objectives (e.g., develop scale economies, reduce costs, reduce risk and create an attractive investment climate, etc.).

- Low- or no-cost implementation options - options to enhance distributed solar adoption with minimal financial outlay relative to direct incentive programs - are available, and may be considered either alongside direct incentives, prior to adoption of incentives, or when there is limited appetite for costlier measures. Certain financing enabling policies and changes to rules and regulations such as revising building codes and implementing targeted tax measures; along with other industry support initiatives can be implemented in various market stages with minimal cost. Specific options are discussed in more detail in Section 4.3.2 in Volume III.

- Sequencing implementation options in a particular order enhances the cost-effectiveness of solar deployment. Figure 1 shows a path of implementation ordering commonly adopted by other states.

Figure 1 – Sequencing Solar Implementation



- Adopting synergetic implementation options can advance support for increased solar penetration, while over-stimulation and duplicative implementation objectives may impede or disrupt healthy market growth.

Other Considerations for Solar PV Implementation

In addition to the key themes and lessons learned, the authors identify a list of considerations that the Legislature may wish to take into account when developing a comprehensive implementation approach:

- Implementation options selected (if any) should align as best possible with the Legislature's definition of priorities and objectives. Table 7 in Volume III identifies a list of objectives organized under 6 implementation priorities: market growth, equity, feasibility, compatibility with Maine's energy market, economic and environmental goals that the Legislature may wish to consider. Because policy objectives like those delineated in Table 7 can conflict - specific implementation options can maximize one objective while working counter to another - it is important that the legislature understand the tradeoffs among these options.

- The Legislature may wish to create leverage with polices and initiatives already in place in other states in the region to finance local projects and support solar PV deployment in Maine. For example, the Maine Legislature may choose to adopt implementation options that leverage net metering benefits with RPS demand in other New England states.

- Implementation objectives and options are subject to constraints. Examples of implementation constraints include federal preemption via the supremacy clause of the US constitution, siting feasibility, and grid interconnection constraints.

Maine Distributed Solar Valuation Study

Volume I: Methodology

Introduction

Methodology Overview

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

Figure 2. Overview of value calculation

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

Competitive Market Structure in Maine

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

Methodology Objectives

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

- Irradiance patterns and shading at PV system geographical coordinates;
- The PV system orientation, such as the azimuth and tilt angle that define the daily generation profile;
- Interconnection point of PV system on the transmission and distribution system;
- Power market prices;
- Conductor sizing on local feeder; and
- Utility financial factors.

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

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

Therefore, the distribution loss model incorporates simplifications that, to the extent possible, promote understanding while yielding representative results. A reasonable simplification is to model the entire distribution system as one device, calibrated such that all annual losses in the model agree with empirical results found in utility-reported annual losses.

Note that the methodology described here could be applied at varying levels of granularity. For example, the method could be applied at the level of the distribution circuit. This would require additional detail in input data (e.g., obtaining loss factors, hourly loads, and solar production profiles

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

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

Value Components

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

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

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

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

Table 1. Value components included in methodology.

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

Solar Penetration

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

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

Marginal Fuel

This methodology assumes that PV displaces natural gas during PV operating hours. During some hours of the year, other fuels (e.g., oil) may be the fuel on the margin. In these cases, natural gas displacement is a simplifying assumption that is not expected to materially impact the overall value.

Economic Analysis Period

In evaluating the value of a distributed PV resource, the economic analysis period is set at 25 years, the assumed useful service life of the PV system[2]. Note that the sensitivity runs described later consider other assumptions for analysis period. The methodology includes PV degradation effects as described later.

Maine's Electric Utility Territories

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

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

[2] National Renewable Energy Laboratory, NREL: Solar Resource Analysis and High-Penetration PV Potential (April 2010). http://www.nrel.gov/docs/fy10osti/47956.pdf
[3] State of Maine Public Utilities Commission 2013 Annual Report (February 2014) http://www.maine.gov/mpuc/about/annual_report/documents/attach.pdf

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

High Value Locations

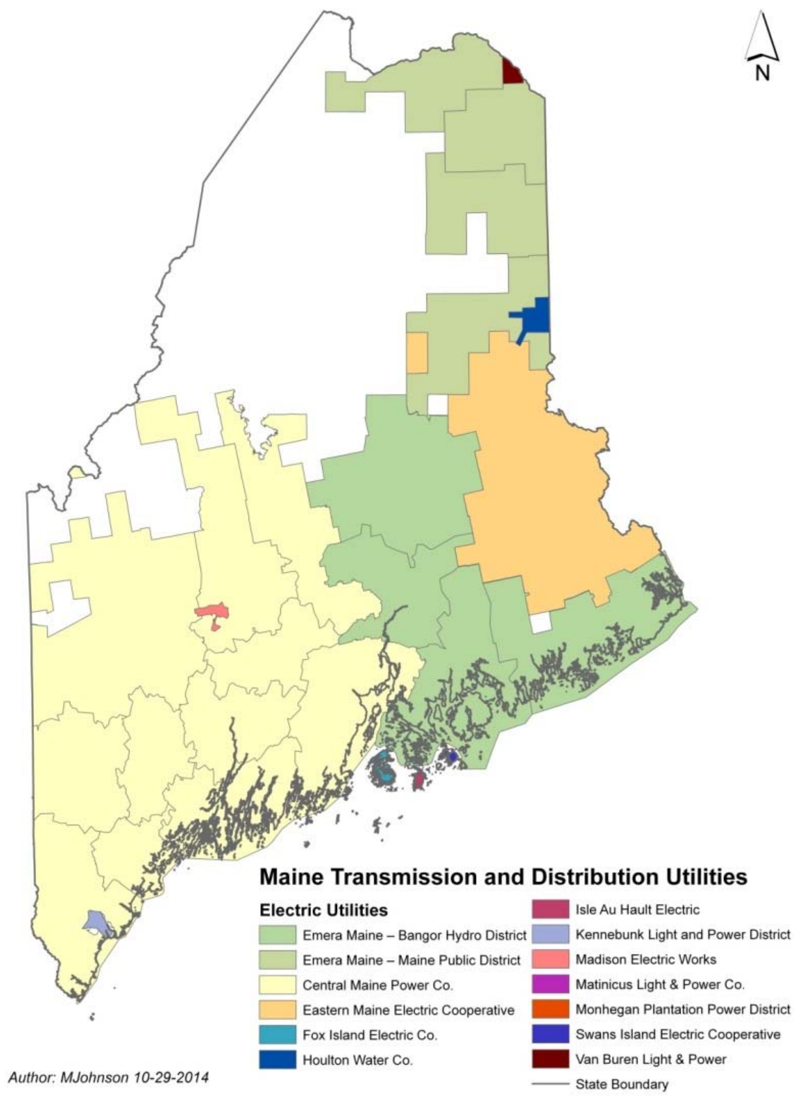
The methodology could be implemented at various load aggregation regions. For example, within a distribution utility, the same methodology could be used to calculate value for different distribution planning areas. Such an analysis may result in differing overall values because of differing input data.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

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

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

[4] The Bangor Hydro Division and Maine Public Service Division of Emera Maine will be treated separately as the two districts are not electrically connected.
[5] http://www.iso-ne.com/main.html
[6] Owned by Emera Maine, and also referred to as Emera Maine - Maine Public District (EME-MPD).
[7] http://www.nmisa.com
[8] The Boothbay Non-Transmission Alternative Pilot Project is an example of a higher value location. See for example "Interim Report: Boothbay Sub-Region Smart Grid Reliability Project," GridSolar LLC, Docket No. 20110138, March 4, 2014.

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



[9] Source: Maine Public Utilities Commission

Methodology: Technical Analysis

Load Analysis Period

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

PV Energy Production

PV System Rating Convention

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

PV Fleet Production Profiles

PV Fleet Production Profiles on an hourly basis over the Load Analysis Period will be developed using the method that follows (see Analysis Approach section for descriptions of other fleet definition profiles that will be included for sensitivity).

The fleet comprises a large set of PV systems of varying orientations (different tilt angles and azimuth angles) at a large number of locations. The intention is to calculate costs and benefits for the PV fleet as a whole, rather than for a specific system with specific attributes.

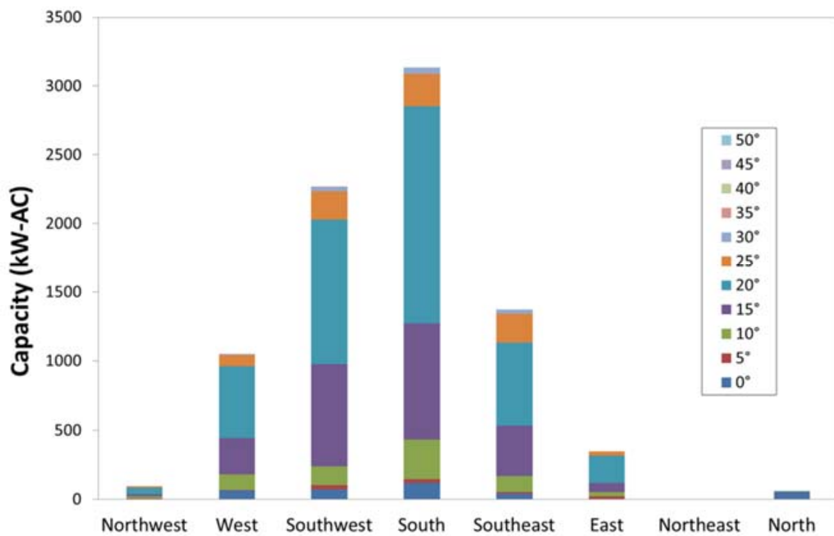
Sets of individual PV resources at the centroid of each zip code in the State are simulated over the Load Analysis Period. For each zip code, individual systems are defined, each having a distinct orientation and a capacity weighted in proportion to the expected capacity for the given orientation. The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

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

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

Simulations are performed using CPR's FleetView™ software, incorporating satellite-derived irradiance data (SolarAnywhere®). Each system will be mapped to its corresponding 10 km x 10 km weather data grid location from which temperature, wind speed, direct normal irradiance, and global horizontal irradiance will be taken. For each hour, the weather data will be used, array-sun angles and plane-of-array irradiance will be calculated, and PV system output will be modeled with temperature and wind speed corrections.

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



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

All systems will be simulated individually, and the results will be aggregated. Finally, the energy for each hour will be divided by the fleet aggregate AC rating. The units of the PV Fleet Production time series are kWh per hour per kW-AC (or, equivalently, average kW per kW-AC).

Marginal PV Resource

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

Annual Avoided Energy

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

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

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

Load-Match Factors

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

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

Effective Load Carrying Capability (ELCC)

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

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

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

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

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

Peak Load Reduction (PLR)

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

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

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

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

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

Loss Savings Analysis

In order to calculate the required Loss Savings Factors on a marginal basis as described below, it will be necessary to calculate ELCC, PLR and Annual Avoided Energy each twice. They should be calculated first by *including* the effects of avoided marginal losses, and second by *excluding* them. For example, the ELCC would first be calculated by including avoided transmission and distribution losses, and then re-calculated assuming no losses, i.e., as if the Marginal PV Resource was a central (not distributed) resource.

The calculations should observe the following

Table 2. Losses to be considered.

Technical Parameter	Loss Savings Considered
Avoided Annual Energy	Avoided transmission and distribution losses for every hour of the load analysis period.
ELCC	Avoided transmission and distribution losses during the 100 peak hours in the ISO-NE control area.
PLR	Avoided distribution losses (not transmission) at peak.

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

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

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

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

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

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

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

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

Loss Savings Factors

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

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

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

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

Similarly, the PLR Loss Savings Factor is defined as:

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

And the ELCC Loss Savings Factor is defined as:

$$Loss\ Savings_{ELCC} = \frac{ELCC_{WithLosses}}{ELCC_{WithoutLosses}} - 1 \quad (5)$$

Methodology: Economic Analysis

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

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

Discount Factors

For this analysis, year 0 corresponds to the year of installation of the PV systems in question. As an example, if the calculation is performed for PV installations between January 1, 2014 and December 31, 2014, then year 0 would be 2014, year 1 would be 2015, and so on.

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

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

DiscountRate is the utility Weighted Average Cost of Capital.

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

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

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

Finally, an environmental discount factor is given by:

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

EnvironmentalDiscountRate is based on the 3% *real* discount rate that has been determined to be an appropriate societal discount rate for future environmental benefits.[13] As the methodology requires a

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

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

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

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

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

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

where PVDegradationRate is the annual rate of PV degradation (see assumptions below). $PVProduction_0$ is the Annual Avoided Energy for the Marginal PV Resource.

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

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

Avoided Energy Cost

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

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

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

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

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

Avoided Generation Capacity Cost

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

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

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

Avoided Reserve Capacity Cost

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

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

Avoided Natural Gas Pipeline Cost

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

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

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

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

Solar Integration Cost

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

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

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

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

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

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

Avoided Transmission Capacity Cost

Distributed PV has the potential to avoid or defer transmission investments, provided that they are made for the purpose of providing capacity, and provided that the solar production is coincident with the peak.

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

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

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

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

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

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

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

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

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

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

Avoided Distribution Capacity Cost

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

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

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

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

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

Voltage Regulation

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

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

Advanced Inverters

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

Based on these considerations, it is reasonable to expect that at some point in the future, distributed PV may offer additional benefits, and Voltage Regulation is kept as a placeholder for future value analyses.

Avoided Environmental Costs

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

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

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

Calculating Avoided Emissions

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

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

Net Social Cost of Carbon

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

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

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

The total avoided SCC for each year is calculated as follows. The SCC values for each year through 2050 are published in 2007 dollars per metric ton.[26] For example, the SCC for 2020 (3.0% discount rate scenario, average) is $43 per metric ton of CO_2 emissions in 2007 dollars. These costs are adjusted for inflation, converted to dollars per short ton, and converted to cost per kWh using the AVERT analysis results, adjusting for PV degradation.

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

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

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

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

Net Social Cost of SO_2

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

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

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

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

Net Social Cost of NO_x

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

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

Market Price Response

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

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[27] http://www.epa.gov/airmarkets/trading/2014/14summary.html
[28] See p. 4-26, Table 4-7, of the Regulator Impact Analysis at http://www2.epa.gov/sites/production/files/2014-06/documents/20140602ria-clean-power-plan.pdf.
[29] For more information, see http://www.epa.gov/crossstaterule/

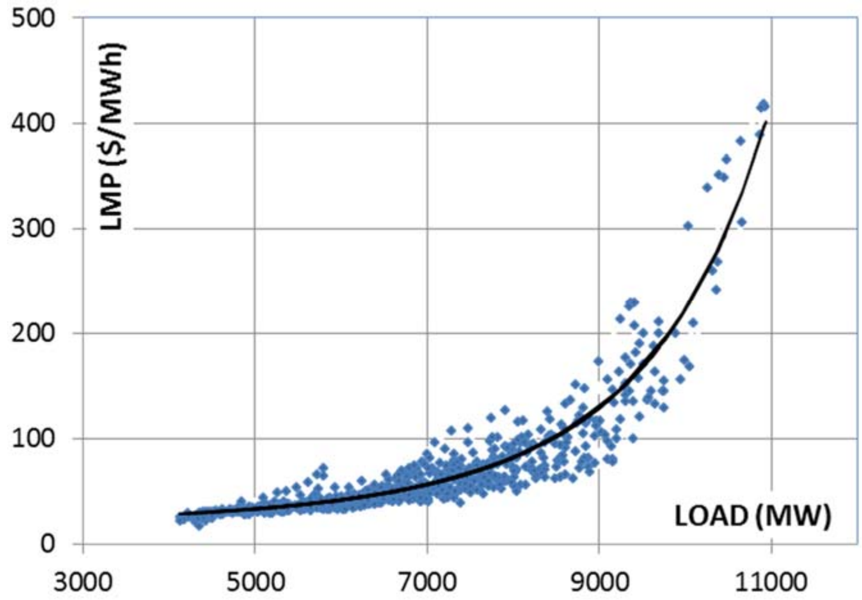

Figure 5. LMP vs. load for a large northeastern utility.

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

Two cost responses occur when distributed PV generation is deployed.

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

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

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

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

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

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

Application of DRIPE results to PV generation

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

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

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

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

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

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

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

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

Underlying assumptions

The market price response calculation methodology makes two key assumptions.

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

Avoided Fuel Price Uncertainty

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

Note that price volatility is also mitigated by other sources (wind, nuclear, and hydro). Therefore, the methodology is designed to quantify the hedge associated only with the gas that is displaced by PV.

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

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

- Repeat for all remaining years in the study period and sum.

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

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

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

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

Appendix 1: Avoided Distribution Capacity Cost

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

Avoided distribution capacity costs are determined using actual data from each of the last 10 years and peak growth rates are based on the utility's estimated future growth over the next 15 years. The costs and growth rate must be taken over the same time period because the historical investments must be tied to the growth associated with those investments.

All costs for each year for FERC accounts 360, 361, 362, 365, 366, and 367 should be included. These costs, however, should be adjusted to consider only capacity-related amounts as shown in Table 3.

Table 3. (EXAMPLE) Determination of deferrable costs.

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

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

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

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

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

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

For each future year, the amount of new distribution capacity is calculated based on the growth rate, and this is multiplied by the cost per kW to get the cost for the year. The total discounted cost is calculated ($149M) and amortized over the 25 years.

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

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

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

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

CONTINUED

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

Validation: Present Value	$166	$166

Appendix 2: Avoided Natural Gas Pipeline Costs

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

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

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

The calculation would be as follows:

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

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 Market Costs $0.090
	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	Societal Benefits $0.092
	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	

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 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
	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

Avoided Market Costs
$0.138

Societal Benefits
$0.199

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.

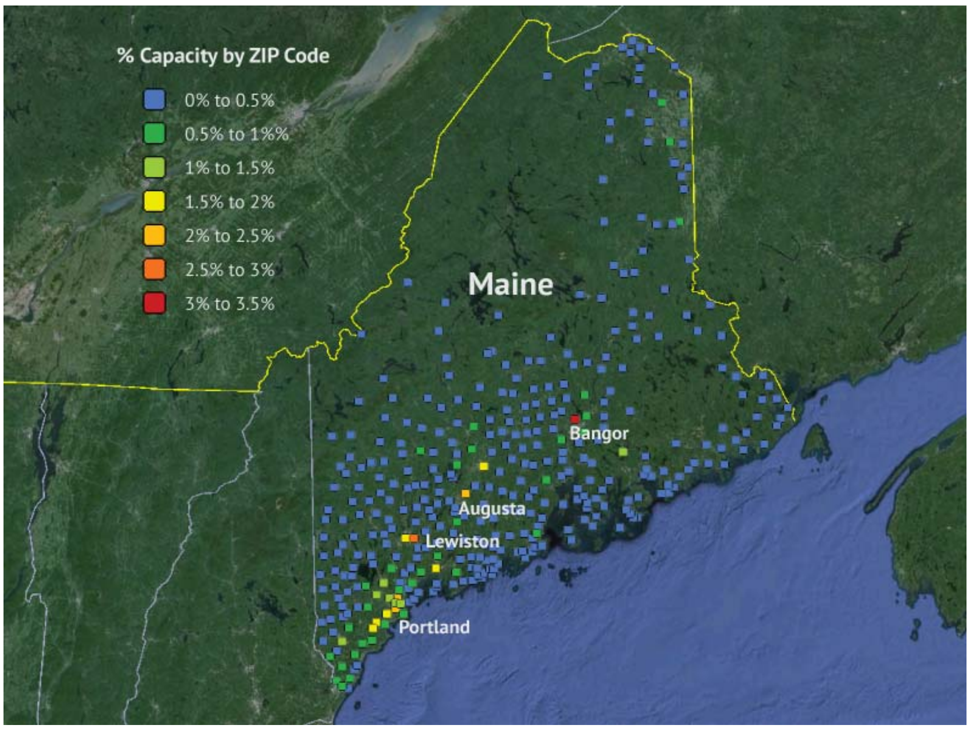
Rated Array Output

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.

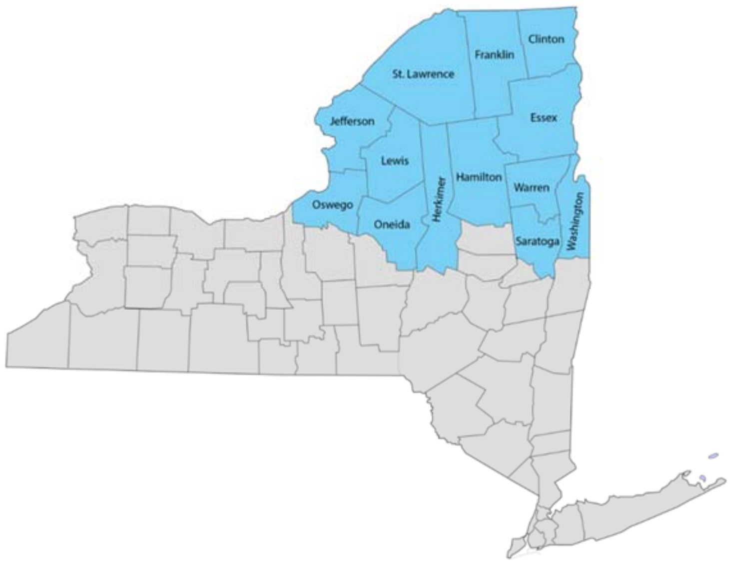
Representative fleets

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)

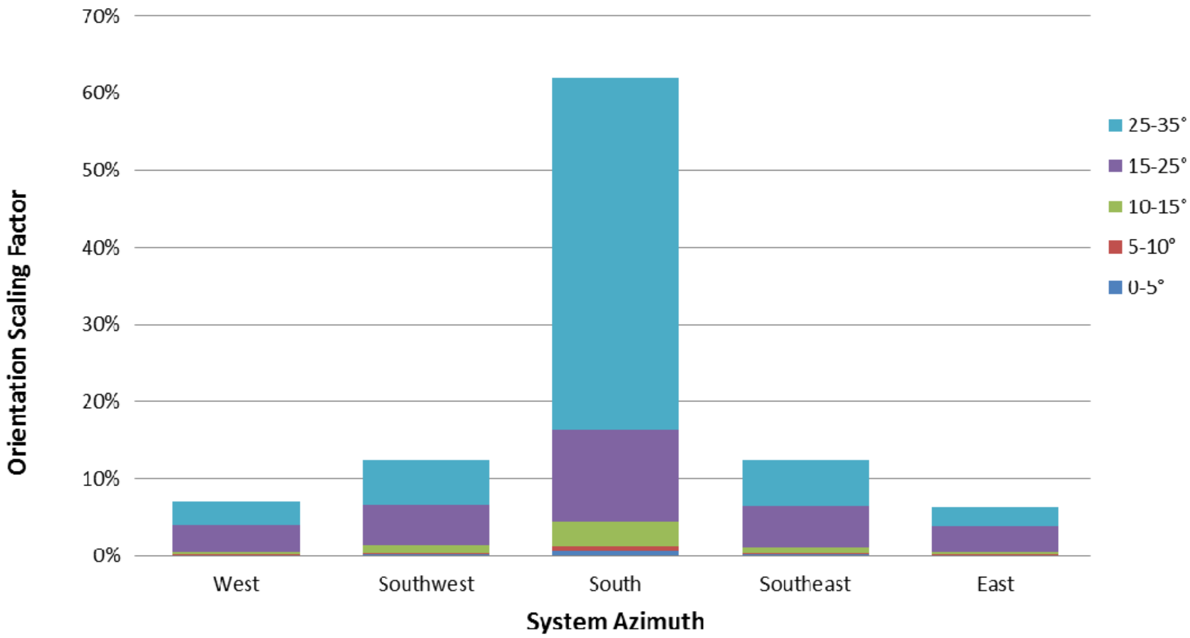


Figure 12. Distribution of rated array capacity by azimuth and tilt angle (Residential)

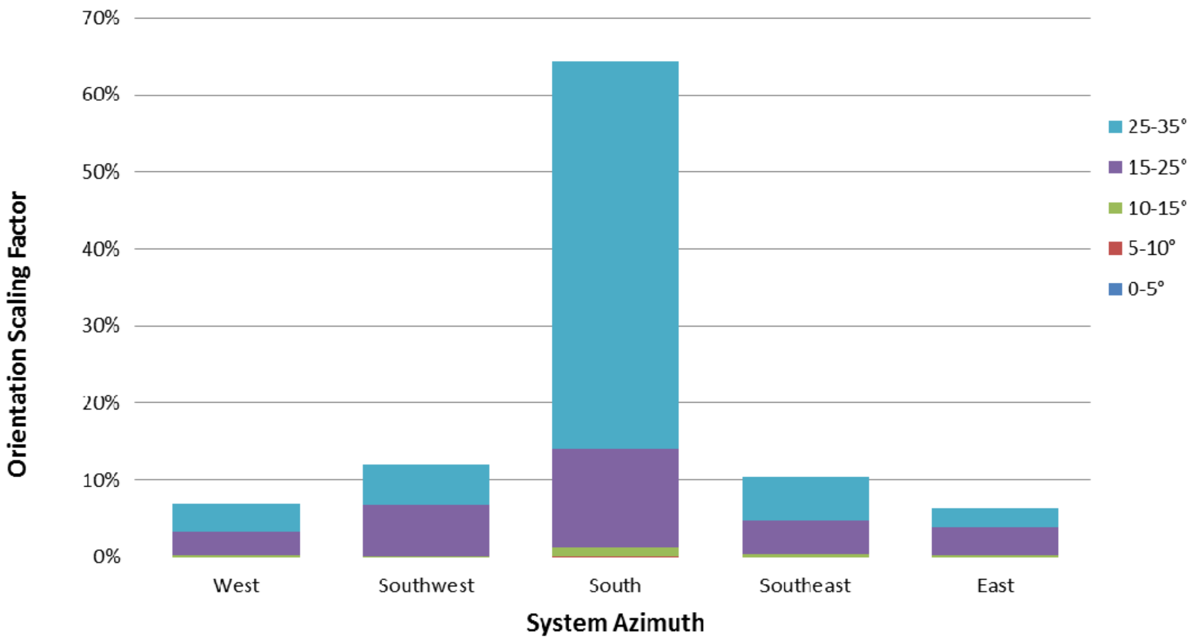
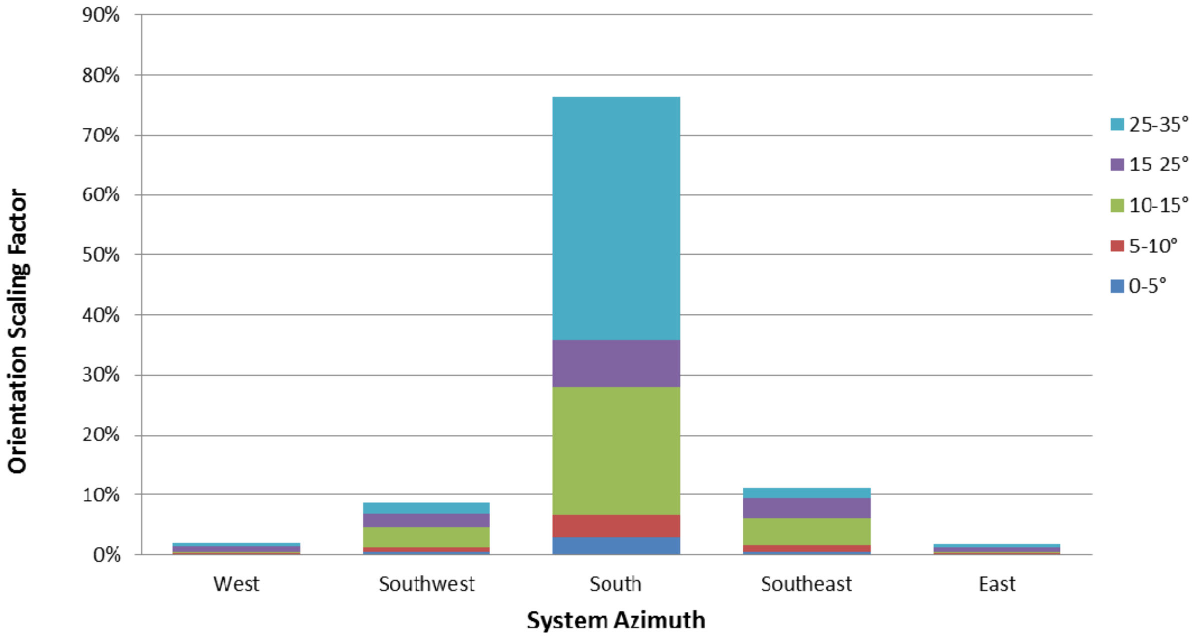


Figure 13. Distribution of rated array capacity by azimuth and tilt angle (Non-Residential)



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						
Tilt	**West**	**240°**	**210°**	**South**	**150°**	**120°**	**East**
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

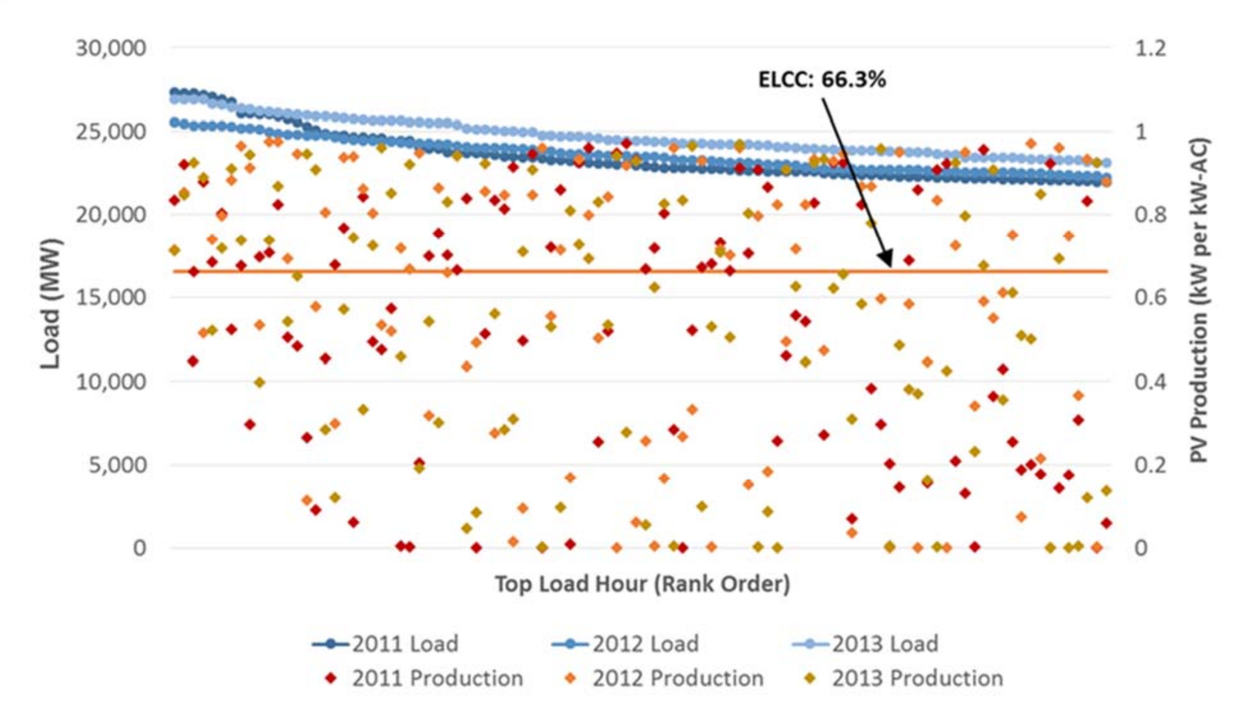


Table 10. ELCC for 42 Candidate Systems at Portland

Azimuth

Tilt	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%	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:

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

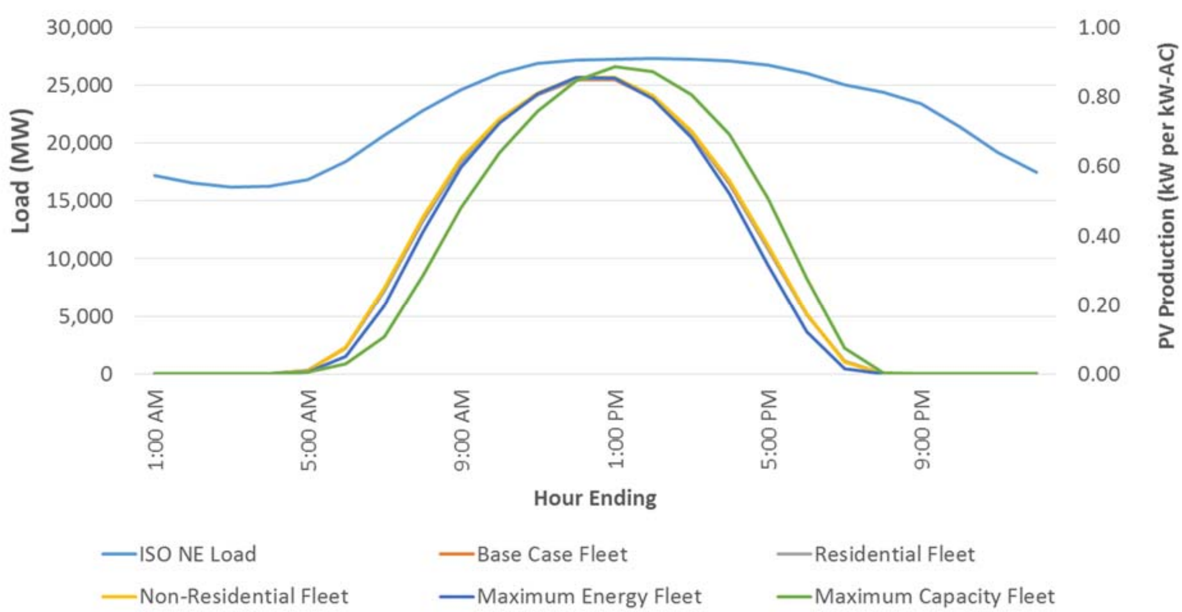
Note that 2.5 kW x 8,760 hours in 2011 = 21,900 kWh. Annual and three-year AC capacity factors were calculated and the three-year minimum, maximum, and average AC capacity factors are shown for each fleet in Table 13.

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

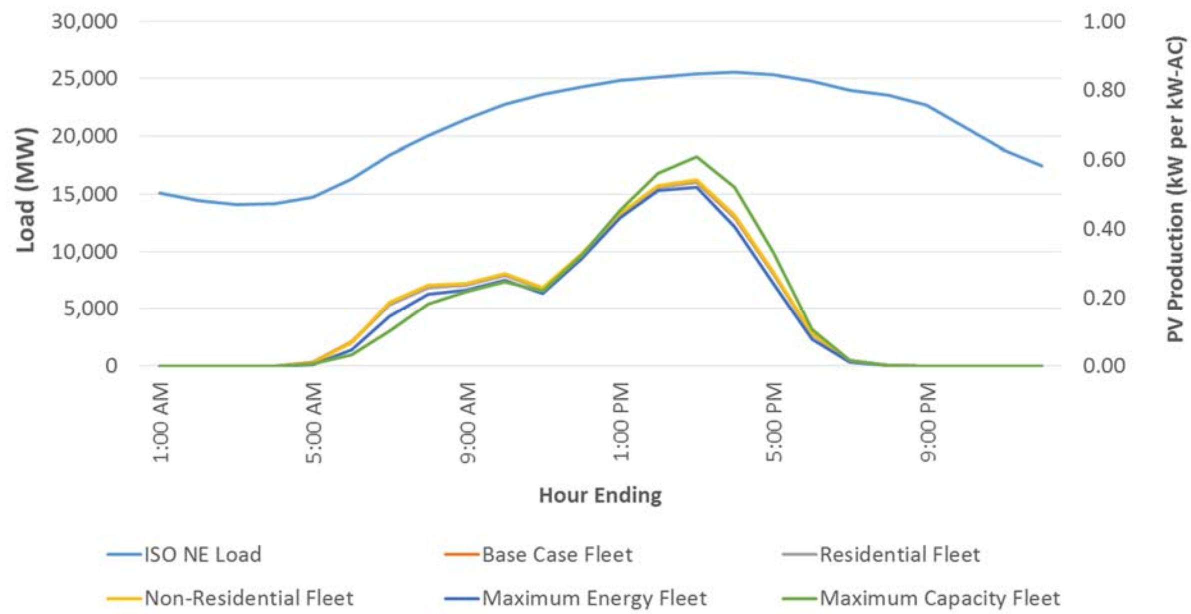
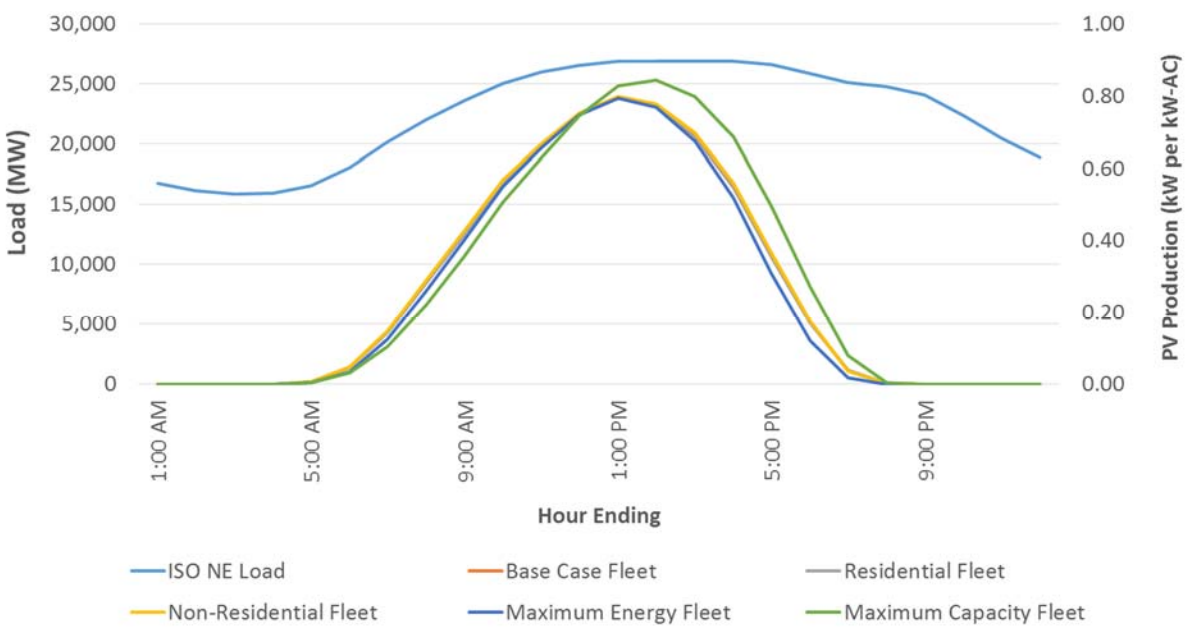


Figure 17. Normalized Fleet Production vs. ISO NE Load on 2013 Peak Load Day – July 19, 2013



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

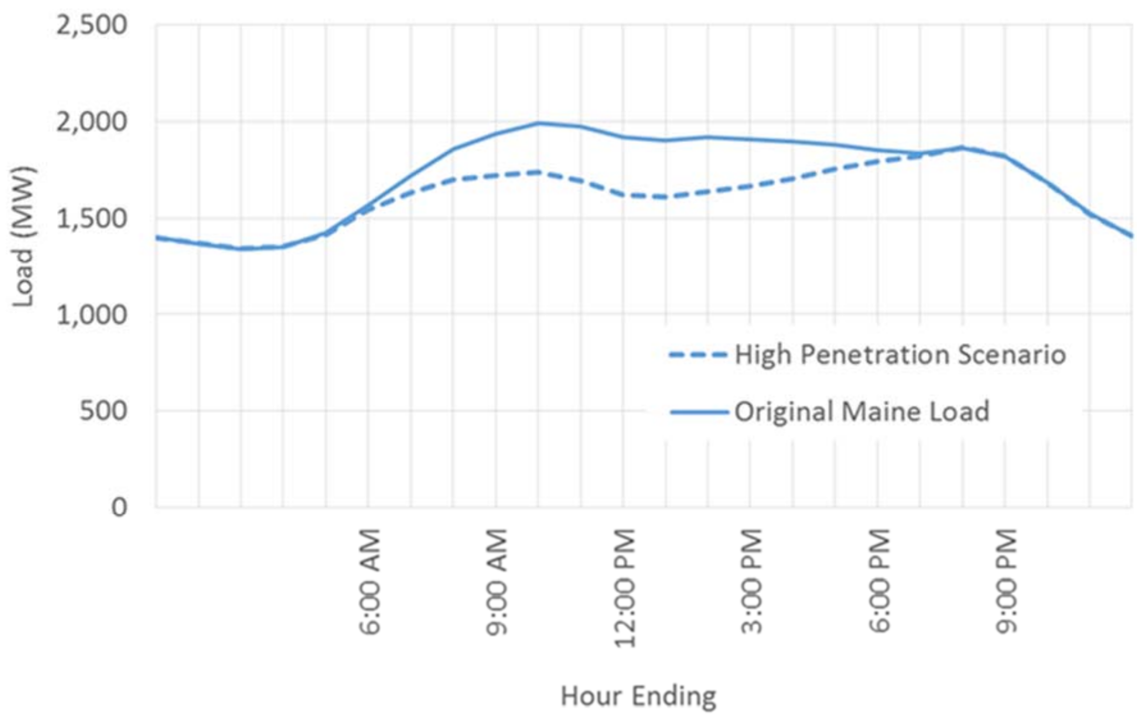


Figure 19. Maine Load Zone Peak 2012 Load Day – August 3, 2012

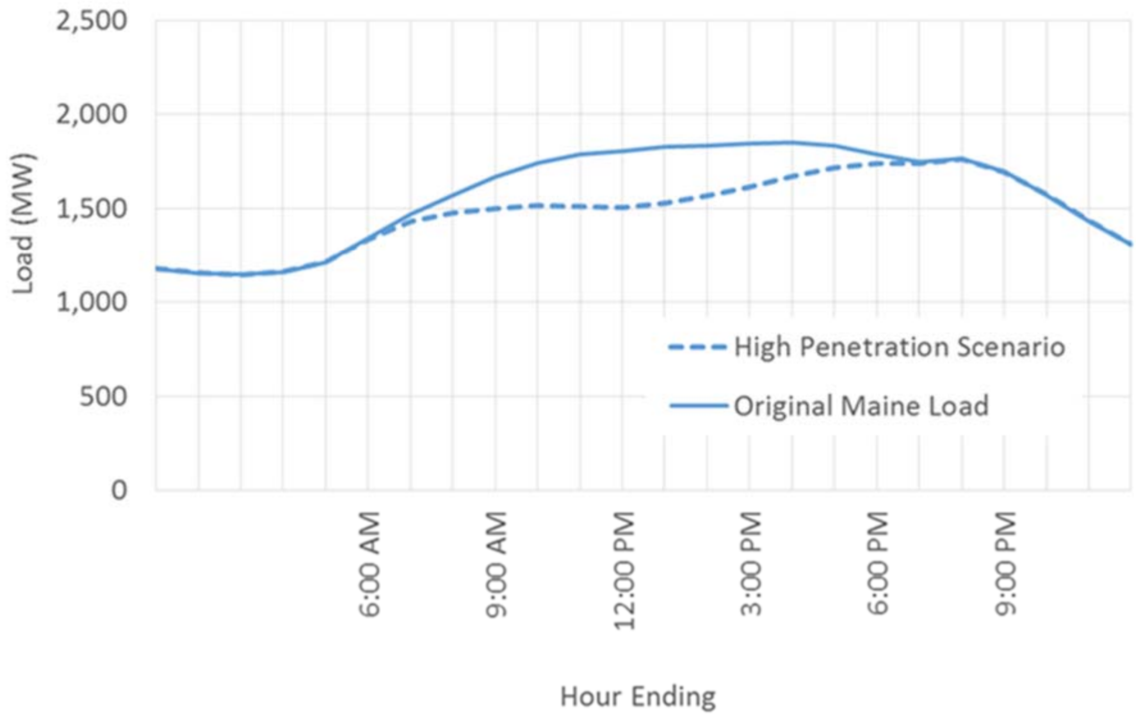
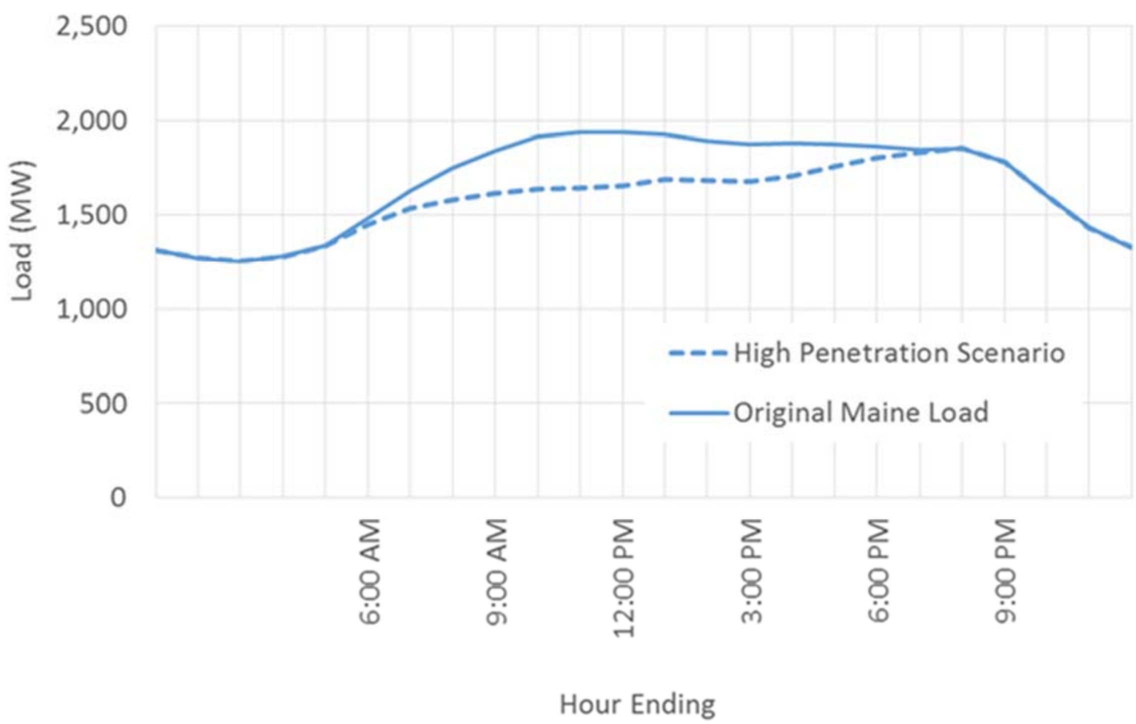


Figure 20. Maine Load Zone Peak 2013 Load Day – July 16, 2012



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.

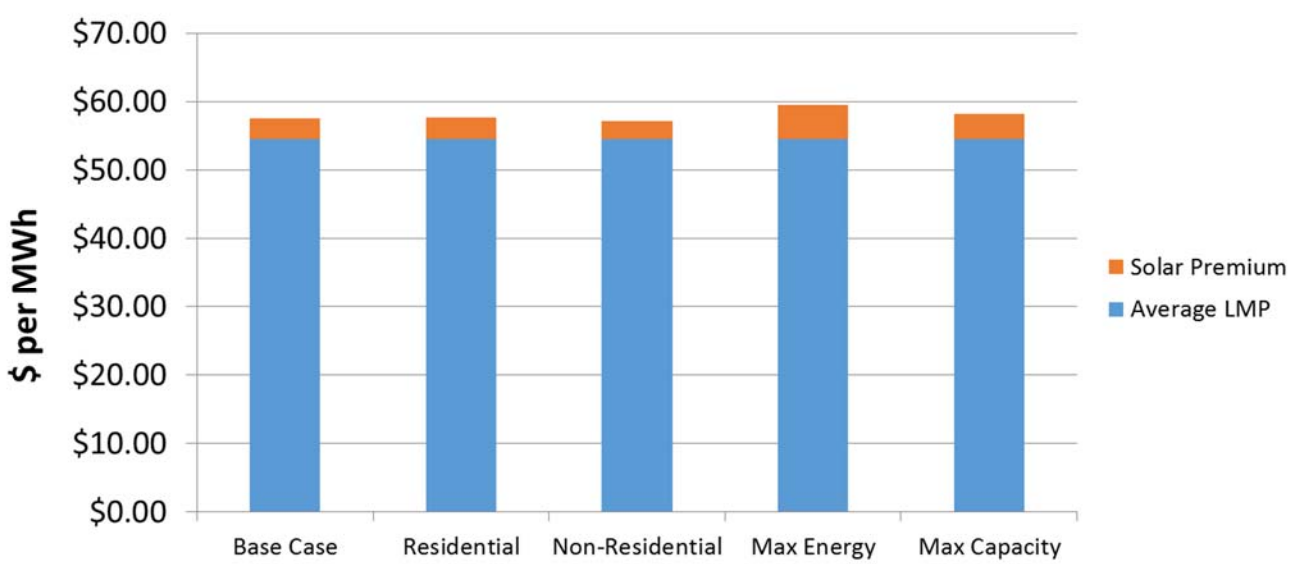
These costs assume no loss savings as if the solar resources were connected directly to the LMP node.

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

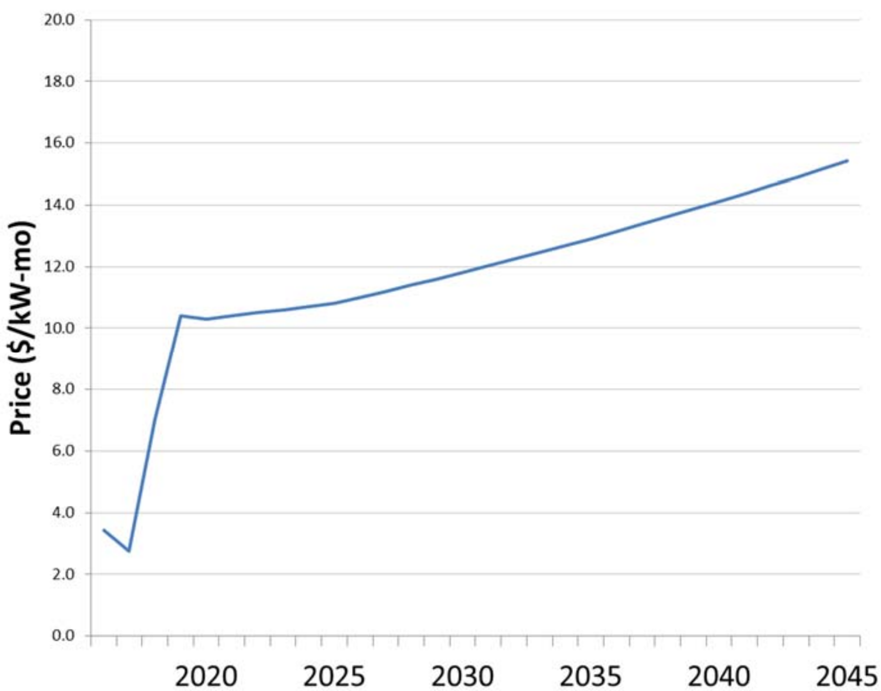
Avoided Generation Capacity Cost

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

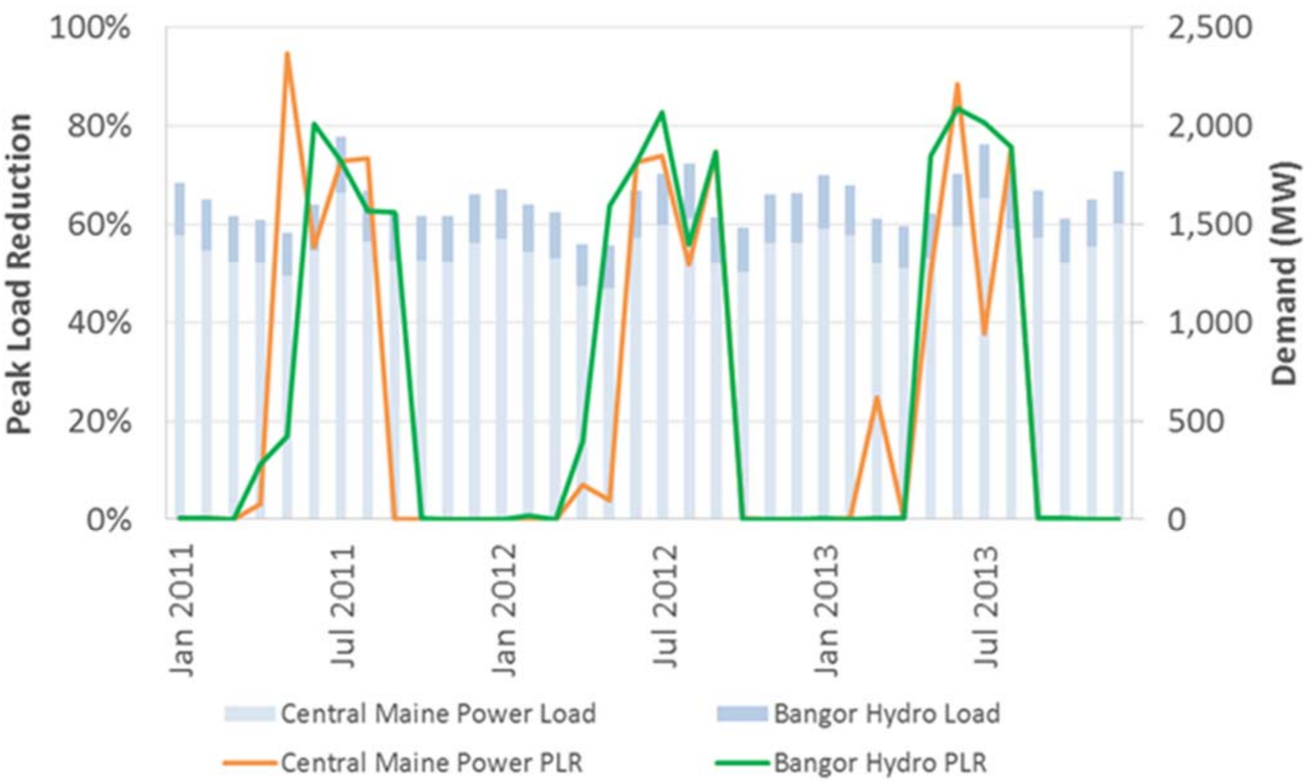
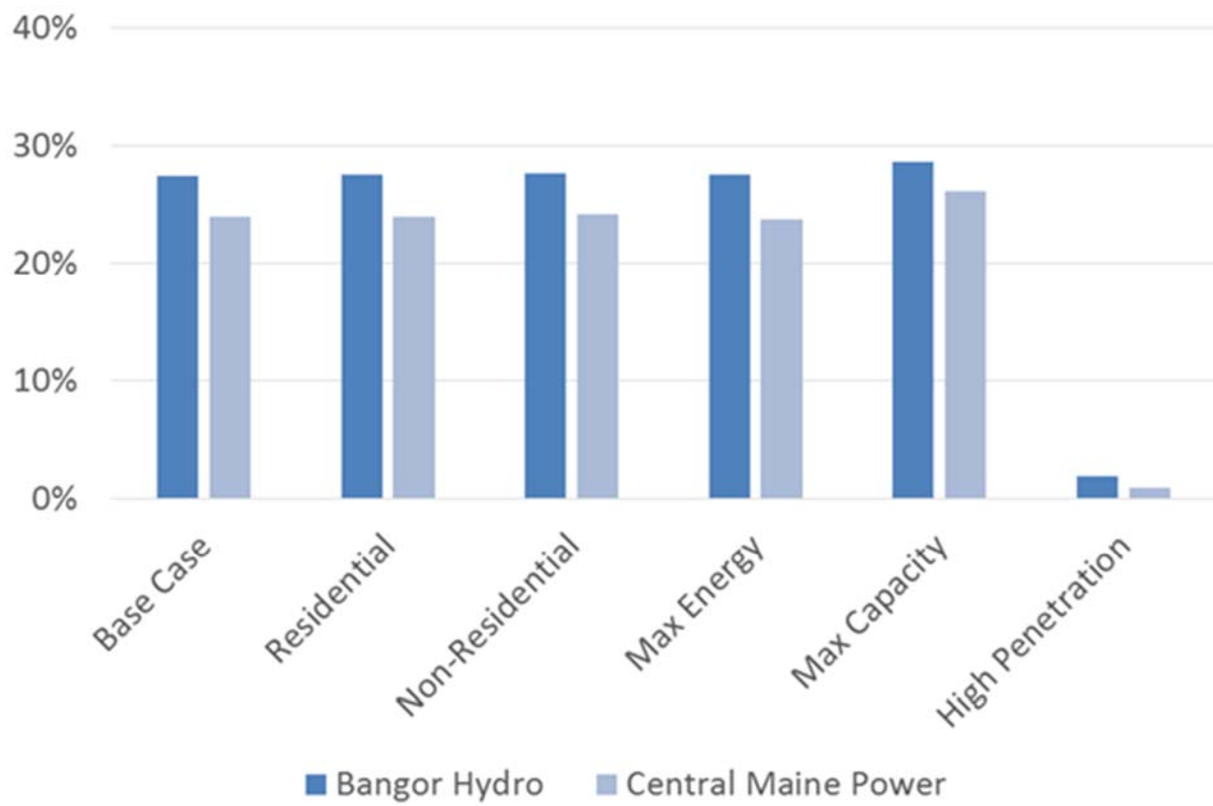


Figure 24. Transmission Peak Load Reductions by Utility and Fleet



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 SO_2, NO_x, and CO_2 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 SO_2 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 NO_x and CO_2 and values for other fleet scenarios are calculated similarly.

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

		2011	2012	2013	Average
Base Case	SO2 (lbs/MWh)	2.067	0.941	1.059	1.356
	NOx (lbs/MWh)	0.867	0.706	0.824	0.799
	CO2 (tons/MWh)	0.600	0.529	0.529	0.553
Res. Proxy	SO2 (lbs/MWh)	2.067	0.941	1.059	1.356
	NOx (lbs/MWh)	0.867	0.706	0.824	0.799
	CO2 (tons/MWh)	0.600	0.529	0.529	0.553
Non-Res. Proxy	SO2 (lbs/MWh)	2.067	0.941	1.125	1.378
	NOx (lbs/MWh)	0.867	0.706	0.875	0.816
	CO2 (tons/MWh)	0.600	0.529	0.563	0.564
Max. Energy	SO2 (lbs/MWh)	2.063	0.889	1.111	1.354
	NOx (lbs/MWh)	0.813	0.667	0.833	0.771
	CO2 (tons/MWh)	0.625	0.556	0.556	0.579
Max. Capacity	SO2 (lbs/MWh)	1.938	0.941	1.118	1.332
	NOx (lbs/MWh)	0.813	0.706	0.882	0.800
	CO2 (tons/MWh)	0.563	0.588	0.588	0.580
High Penetration	SO2 (lbs/MWh)	2.067	0.824	1.000	1.297
	NOx (lbs/MWh)	0.867	0.647	0.765	0.759
	CO2 (tons/MWh)	0.600	0.529	0.529	0.553

The SO2 and NOx 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 SO2 and NOx 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 SO2 and NOx 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

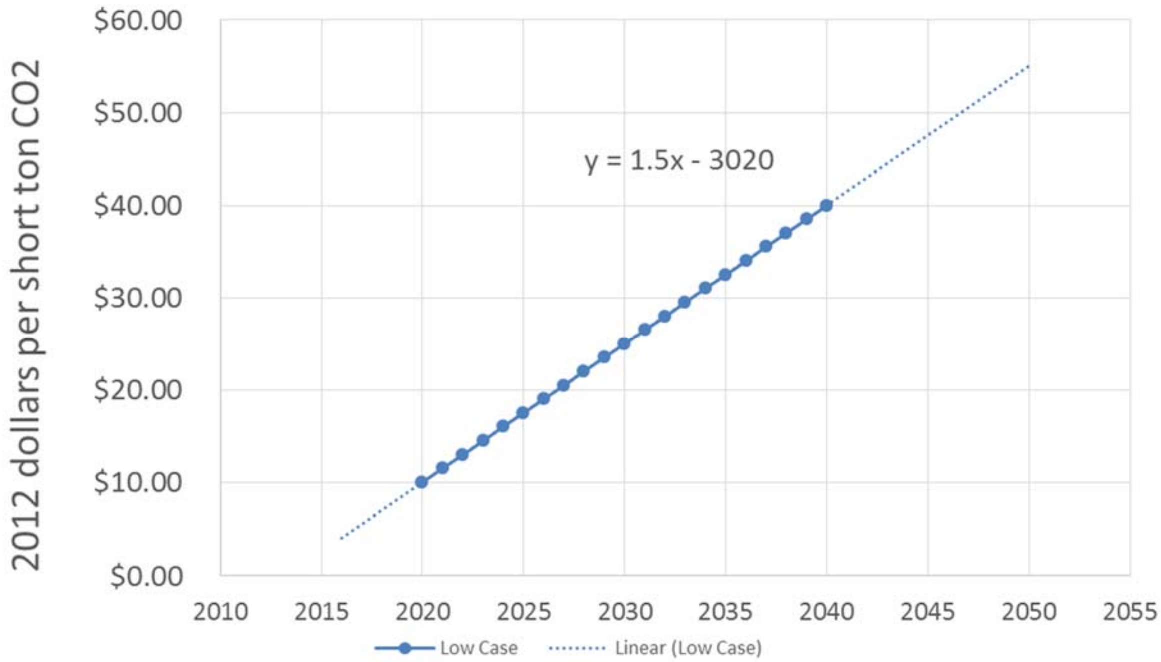
The net social costs of these pollutants were calculated as described in the methodology, subtracting out compliance costs that are embedded in the LMPs.

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

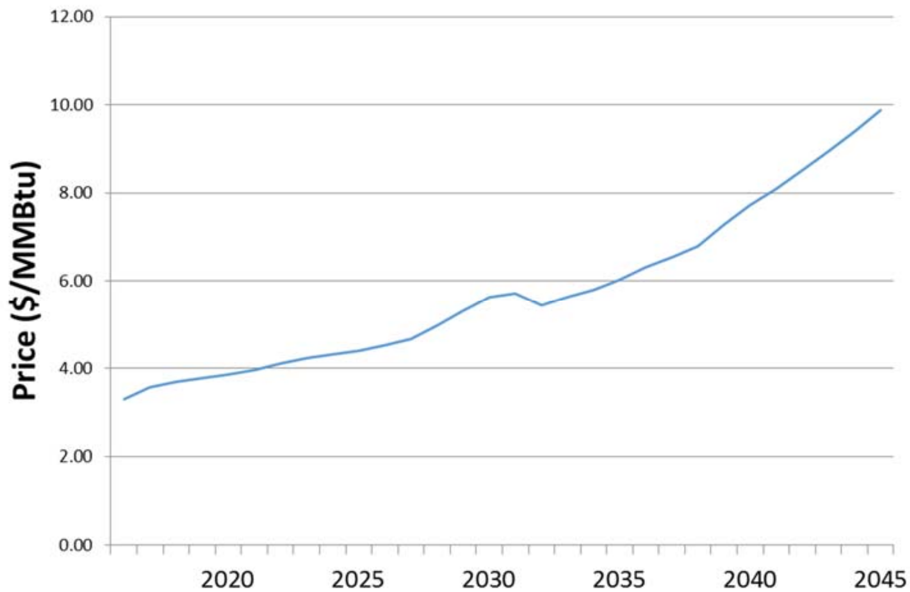
Table 25.**Capacity DRIPE ($/kW)**

	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.

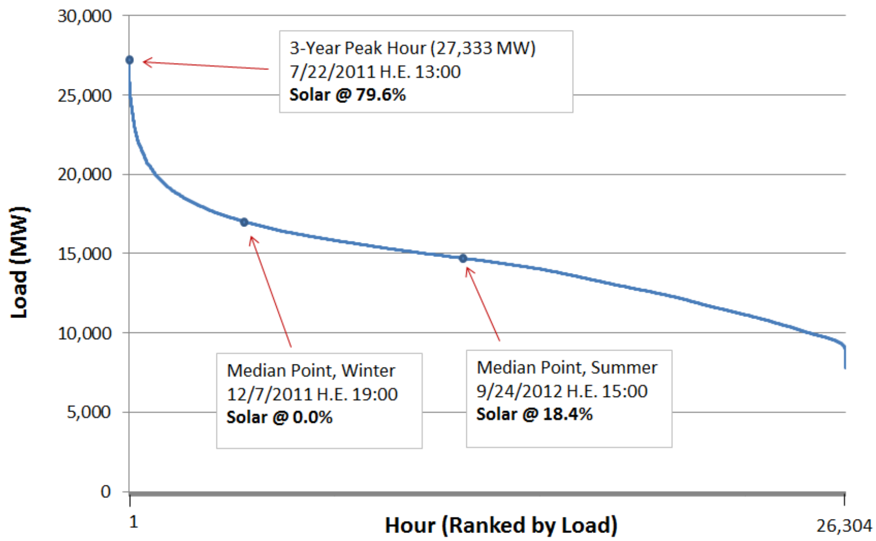
To determine why the discrepancy is so large, an additional analysis was performed, considering only the 10 highest peak load hours over the three year period. The results are shown in Table 37. The top 10 hours are found in two days: July 22, 2011 and July 19, 2013. The average output during these 10 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)

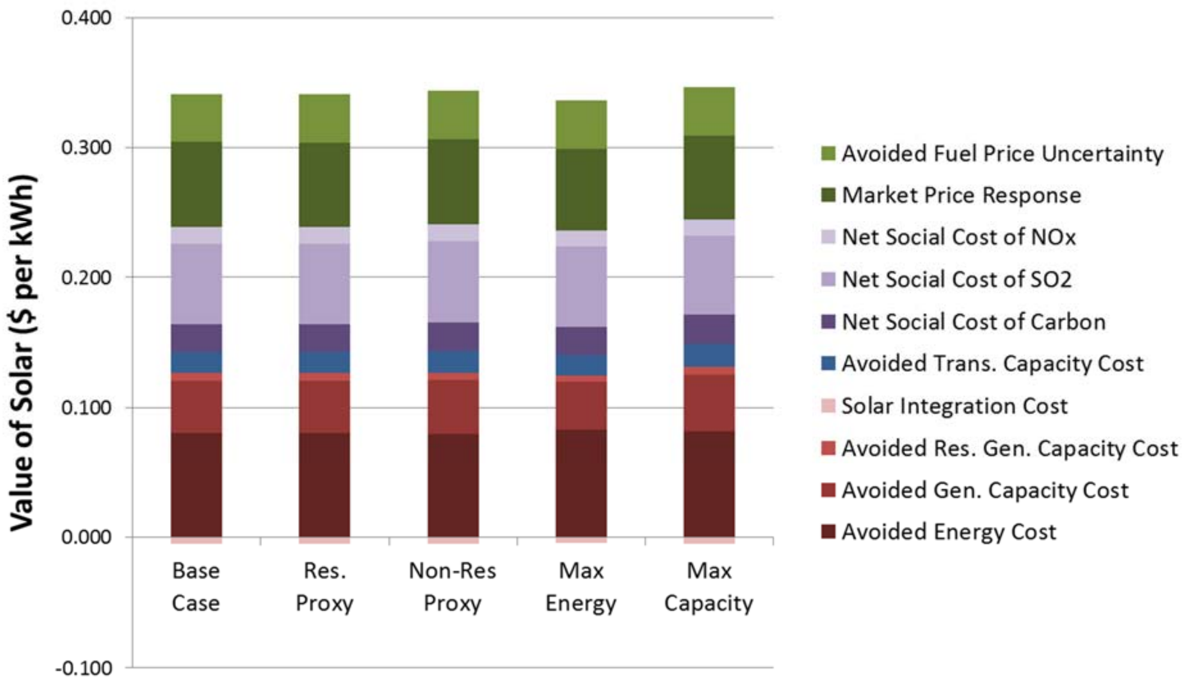


Figure 29. PV Life Sensitivity (CMP)

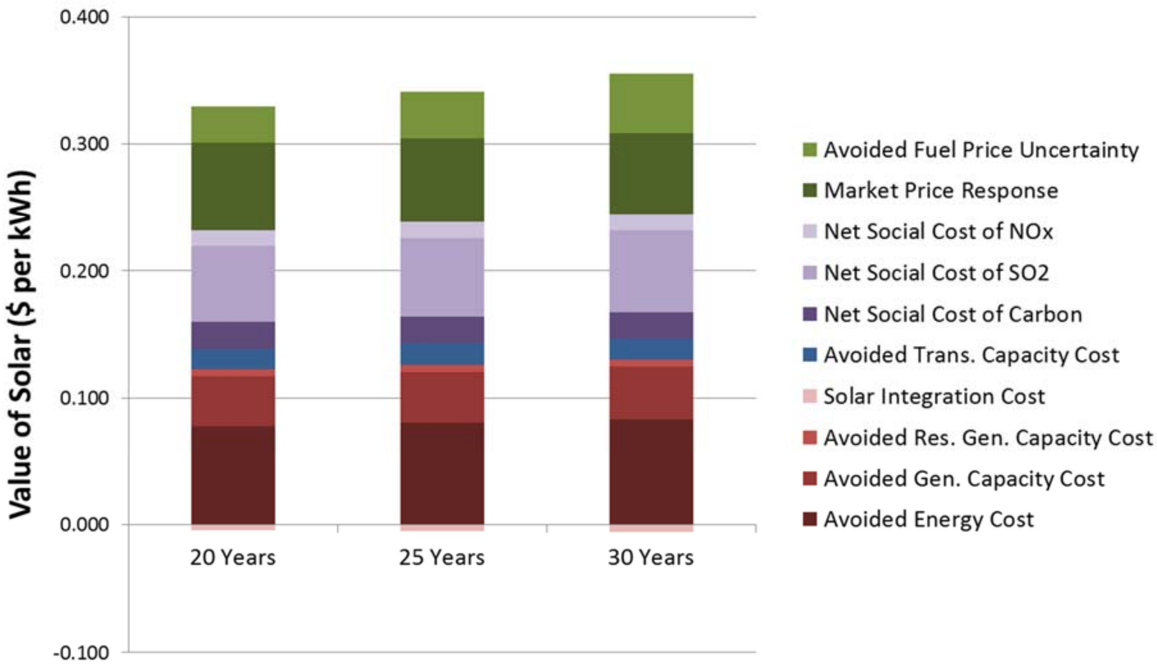


Figure 30. Degradation Sensitivity (CMP)

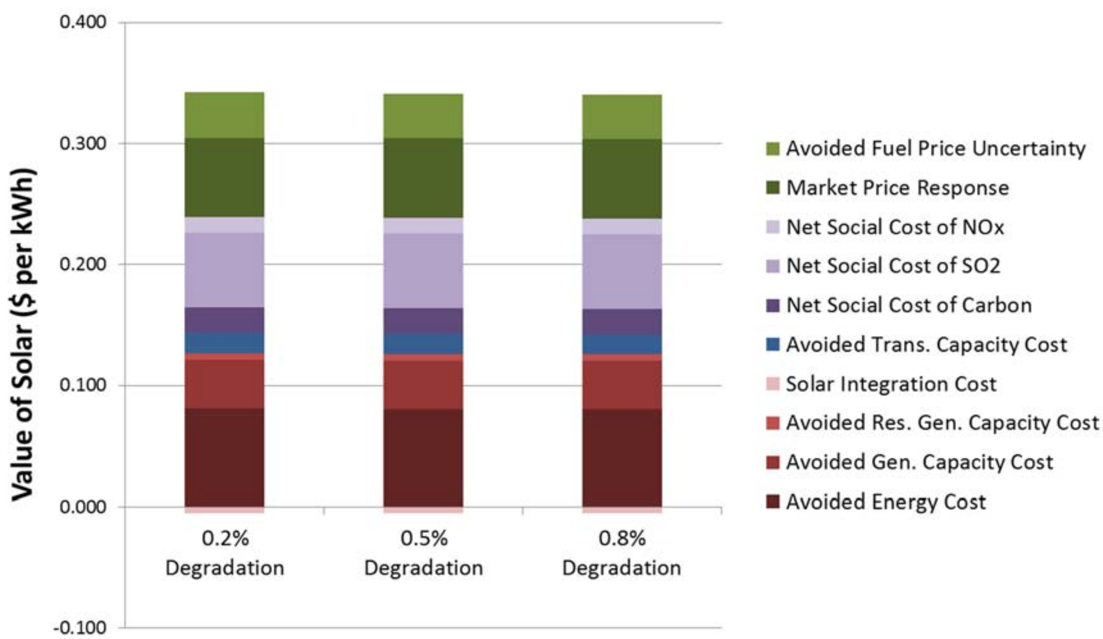


Figure 31. High Penetration Sensitivity (CMP)

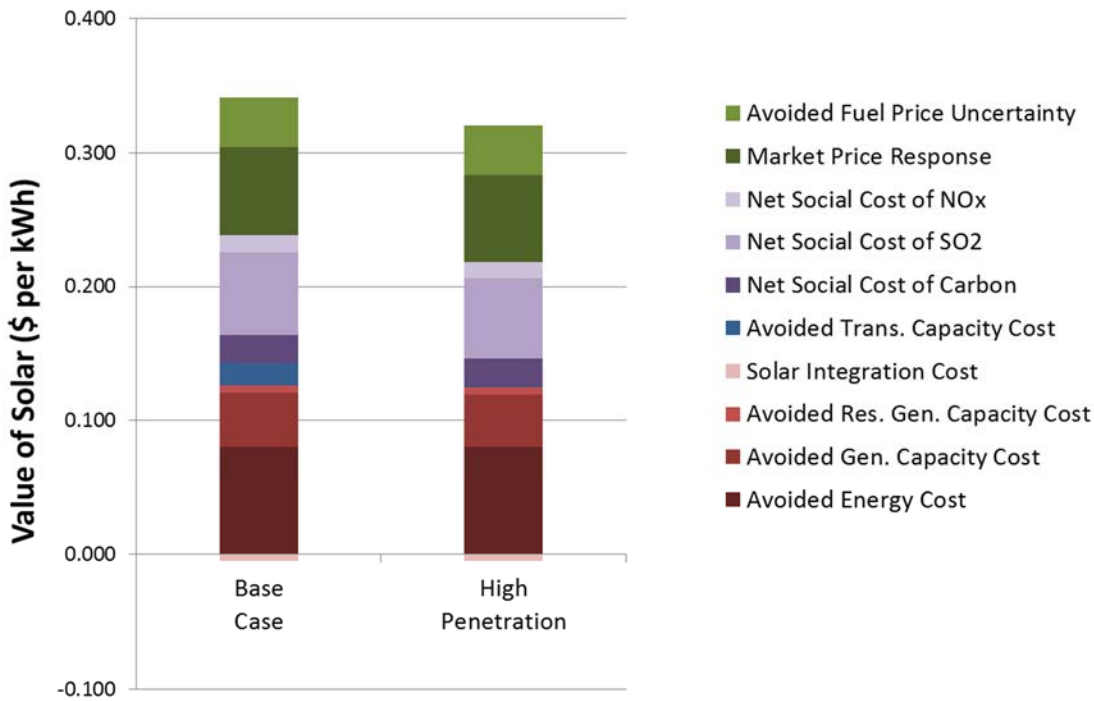
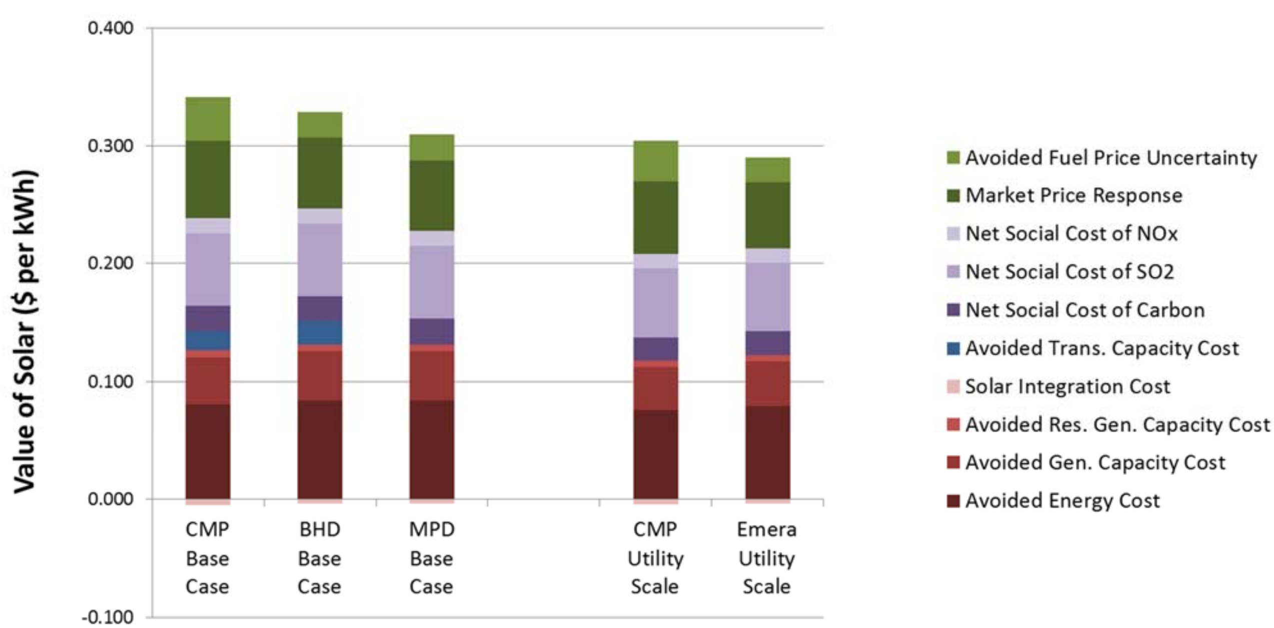


Figure 32. Transmission-connected ("Utility Scale") Sensitivity



Maine Distributed Solar Valuation Study

Volume III: Implementation Options

Introduction

Background

Act to Support Solar Energy Development in Maine. P.L Chapter 562 (April 24, 2014) (codified at 35-A M.R.S. §§ 3471-3473) ("Act") sought information on options for distributed solar energy implementation. This volume provides analysis of options for increasing investment in or deployment of distributed solar generation that are used in other states or jurisdictions. In particular, it concentrates on experience with solar implementation approaches in states with similarities to Maine in market structure (deregulated) and economic opportunity (driven by insolation, land use, electricity prices, etc.), including New England, New York and select PJM states. The authors have also provided general guidance to help the Legislature consider which options, approaches or models may be appropriate for Maine, considering the State's utility market structures.

Approach and Structure

In conducting this analysis, the authors first identified a baseline of current solar-related policies in Maine. Next, the authors reviewed solar PV implementation approaches in place in states with similarities to Maine in geographic location, market structure, and economic opportunity. In addition, the authors conducted a review of recent literature (published in 2012 – 2014) on solar implementation approaches and best practices, distributed generation (DG) policies and utility DG tariff design conducted by a variety of national and state renewable energy policy research organizations and policymakers. Through the literature review, the authors established a list of solar implementation options adopted in the selected states. The implementation options were organized into relevant categories within a comprehensive framework. The authors examined these options, their strengths and limitations in the view of different constituent groups, and how they interact with policies and programs in place. The authors then analyzed the different options, and identified some key characteristics and approaches that would be appropriate for consideration in Maine give the current state of policy and market.

As the volume of distributed solar installations nationwide has rapidly expanded over the past few years, a tremendous amount of experience in solar implementation is becoming available on how legislators and policymakers may make choices that enable, shape or limit that deployment. In reviewing this volume, readers should take into consideration that the field of distributed solar implementation is evolving rapidly, and new studies and approaches are appearing, being proposed or put into practice almost daily in the laboratory of the states. In addition, many implementation options have only been in effect for a limited time and in a few locations. The available data may not be readily extrapolated in all instances. In addition, there are important regional differences – in amount of sunshine, market structure, level of retail and wholesale rates, load growth patterns, and transmission and distribution system characteristics, which could impact the interpretation of that experience. Finally, as the Legislature considers solar implementation options, while an environment of policy stability is important in attracting private investment, most state policies examined have been adjusted and modified during the first few years of implementation, so a spirit of experimentation may be warranted.

Solar Implementation Options

This volume provides a broad overview of implementation options used in other states and jurisdictions to increase investment in or deployment of distributed solar generation. We started by identifying a thorough list of solar implementation option in widespread use. To organize and facilitate discussion of the wide range of implementation options identified, we organized the range of implementation options into four major categories - **Instruments Used to Incentivize Solar; Financing Enabling Policies; Rules, Regulations and Rate Design;** and **Industry Support** – as well as a number of subcategories, as laid out in Table 38. The list includes a broader set of implementation options than are fully evaluated in this volume. Each of these implementation options is described in Section 0. Options in shaded rows were identified as commonly used implementation options but of less potential interest for legislative consideration, and are only discussed briefly in Section 0, while all others are more fully described and characterized.

Table 38 – Summary of Solar Implementation Option

Category	Subcategory	Implementation Examples
Instruments Used to Incentivize Solar	Direct Financial, Up-front Incentives (nameplate capacity-based or denominated)	Grants, Rebates, or Buy-Downs
	Direct Financial, Performance-Based Incentives (PBIs) (energy-based or	Feed-In-Tariffs, Standard Offer[43] PBI Contracts or Tariffs, or PBIs (RECs, Energy, or Capacity)
		Competitive Long-Term PPAs

[43] The use of the term “standard offer” in this report is not to be confused with Maine’s application of the term “standard offer service.” In this report, “standard offer” refers to an incentive option that offers pre-determined, fixed incentives (such as up-front incentives like rebates, or long-term fixed prices, like a feed-in tariff) to any eligible generator. Maine refers to “standard offer service” as electric generation service provided to any electricity consumer who does not obtain electric generation service from a competitive electricity provider or who has terminated service from a competitive electricity provider. (Maine Public Utilities Commission, n.d.)

Category	Subcategory	Implementation Examples
	denominated)	Long-Term Value of Solar Tariffs
		Technology-Specific "Avoided Costs"
	Indirect Financial Incentives	Emissions Markets
	Expenditure-Based Tax Incentives	Investment Tax Credits
	Production Tax Incentives	Production Tax Credits
	Demand-Pull/Solar Minimum Purchase Mandates	Renewable Portfolio Standards (RPS)
		Solar Set-Asides in RPS (SREC markets)
	Net Metering	Net Metering Crediting Mechanism
		Virtual Net Metering Crediting Mechanism
		Community-Shared Solar
Financing Enabling Policies		Solar Load Programs (Non-Subsidized or Indirectly Subsidized)
		On-Bill Financing
		PACE Financing
		Green Bank – Institutions and Suite of Other programs (e.g. Interest Rate Buy-Downs, Loan-Loss reserves, Loan Guarantees, Public Financing)
		Utility Ownership
		Solar Lease and/or Third-Party Ownership Enabling Policies or Eligibility in Other Policies
Rules, Regulations and Rate Design	Removing Institutional Barriers	Interconnection Standards
		Solar Access Laws
		Business Formation/Financing Laws (e.g. Securities Registration, Innovative Market Structures, such as Crowd-Funding, Cooperatives, Community Solar, etc.)

Category	Subcategory	Implementation Examples
		Permitting Standardization, Simplification, and Streamlining, and Other “Soft-Cost Reduction” Strategies
	Building Codes	Solar-Ready Building Standards, Zero-Energy Capable Home Standards
	Tax	Property Tax Exemption or Special Rate
		Sales Tax Exemption
		Property Tax/PILOT Standardization or Simplification
	Grid Modernization	Policies Enabling Microgrids, Smart-Grid and Other DG-Friendly Grid Architecture
	Rate Design	Time-varying rates, rate design, fixed charges and minimum bills
Industry Support		Incentives for Companies, Technology Development Funds, or Economic Development Funds
		Local Content Bonus Or Mandate
		Customer Acquisition Cost Reduction (e.g. Solarize Initiative)
		Outreach/Education/Public Information/Voluntary Market Encouragement
		Public Sector Leadership and Demonstration (e.g. Solar on Schools)
		Creation of Public Good Funds to Support Solar Programs/Policies
		Installer and Inspector Training and Certification

Organization of This Volume

This volume is organized as follows:

Section 0 summarizes the current solar implementation mechanisms in Maine.

In Section 0, solar implementation options adopted in states in the Northeast United States are identified using the categorization framework outlined in Table 38. The major implementation options are described, along with their objectives, target markets, key structural variations, impacts on different stakeholders, implementation issues, and typical interaction with other approaches.

Section 0 identifies illustrative implementation objectives designed to identify which approaches are potentially appropriate for consideration in Maine. The section also summarizes lessons learned from other states and the authors' literature review regarding solar PV implementation. Finally, the section presents a list of factors the legislature may wish to consider when designing an implementation approach. .

A summary of references is also included.

Current Solar Implementation Mechanisms in Maine

Maine has adopted a broad range of policies related to renewable resource development. These policies primarily focused on utility-scale renewable energy resources, such as biomass, hydroelectric, onshore wind, and offshore wind and tidal generation, as well as enabling distribute generation more generally. Although some of these policies do apply to solar, Maine does not currently have a suite of policies specifically targeting solar energy. The current suite of policies, in combination with regional Renewable Portfolio Standard demands, have stimulated some degree of distributed solar PV installations in Maine, particularly in the last few years.

Solar Rebates

To reduce the up-front cost of solar PV, the state, between July and December, 2010, offered residential and business customer rebates for solar systems 100 kW or smaller through the Efficiency Maine Trust. (P.L. 2009 Ch. 372, 2009). The program provided rebates at 0.005₵/kWh. The program was repealed effective December 31, 2010 (35-A MRS § 10112, n.d.).

Net Metering

Net metering for solar PV has been available in Maine since the early 1980s. As of the end of 2014, the utilities report that Maine had an aggregate net-metered installed capacity of about 21 MW, with about 11.7 MW being solar PV. Under Maine's net metering rules, investor-owned utilities are mandated to provide net metering to owners[44] of eligible systems (including solar PV, fuel cells, wind, geothermal, hydroelectric, biomass, landfill gas, anaerobic digestion, micro-combined heat and power facilities) with an installed capacity of 660 kW or smaller.[45] Consumer-owned utilities are only required to provide net metering to systems up to 100 kW in installed capacity, but can choose to increase the system cap limit to 660 kW at their own discretion. Net metering customers are credited for the excess generation as a reduction in energy usage for the following months for up to twelve months. Any accumulated unused credits will expire at the end of the twelve-month period. Unlike many other nearby states, Maine does not have an aggregate program cap, but utilities are required to inform the Commission when the total net-metered capacity reaches 1% of the utilities' peak loads. (Maine Public Utilities Commission, 2009).

[44] The Commission rules are flexible to accommodate arrangements similar in nature to ownership (such as certain lease-type arrangements), but not sufficient to allow for 3rd-party sales arrangements.
[45] Unlike many states, generation need not be behind-the-meter to receive net metering credits.

Shared Ownership Net Metering

In 2009, the Maine Legislature authorized shared ownership net metering, which allows up to ten customers to share ownership interest in a single facility. Under the shared ownership rules, the net metering customers must be owners of or have “legally enforceable rights and obligations” in the net metered facility. Similar to Maine’s regular net metering, customers are credited for a percentage of the excess generation of the facility on their utility bills in proportion to their ownership interest of the facility. (Maine Public Utilities Commission, 2009). This provision effectively enables community-shared solar ownership, a model that has become increasingly common in recent years. Based on utility net metering reports to date, there is one shared ownership net metering arrangement in operation for solar PV.

Shared ownership is a form of virtual net metering. Many other states have virtual net metering rules that, unlike Maine, allow sales or transfer of net metering credits to offset billed charges of parties who do not have an ownership in the net metered facility.[46]

Renewable Portfolio Standard

Maine’s version of the policy implementation approach commonly referred to as a Renewable Portfolio Standard (RPS) was created in phases. To support pre-restructuring grid-scale renewable energy facilities, the Maine Legislature adopted a 30% eligible resource portfolio requirement that became effective in 2000 (35-A M.R.S. § 3210(3)). This requirement mandated that retail electricity providers source 30% of their supply from eligible renewable energy generators of any vintage. Since Maine’s legacy eligible resource fleet exceeded the 30% standard by a wide margin, this requirement has been in surplus since its inception, with market prices for renewable energy certificates (RECs) used for compliance trading at a very low price (typically in the range of $1/MWh) insufficient to support any new renewable energy development.

In 2007, the Legislature enacted a “new” renewable resource capacity portfolio requirement (35-A M.R.S. § 3210(3-A)). This new requirement, referred to as the Class I RPS (the previous RPS requirement was rechristened as Class II), defines eligibility as a renewable resource that began service, resumed operation or was substantially refurbished after September 2005. The initial Class I RPS requirement was set at 1% of load in 2008 and escalates annually at 1% per year until reaching 10% in 2017 and remaining at that level thereafter. (Maine Public Utilities Commission, 2007) (Maine Public Utilities Commission, 2014) While solar PV is eligible toward compliance for the Maine RPS Class I (Maine Public Utilities Commission, 2014), historically the RPS has not resulted in promoting investment in solar PV primarily

[46] Some states limit virtual net metering to sharing net metering credits to common ownership of meters or accounts, while others allow broader sharing with unrelated parties throughout the distribution company service territory. See Section 0 for more information.

due to inadequate price levels, and in the authors' analysis, this situation is not envisioned to change any time soon. Community-Based Renewable Energy Pilot Program

P.L. Ch. 329, enacted in 2009, directed the Commission to establish and administer a pilot program to support the development of community-based renewable projects, defined as locally-owned generating facilities with installed capacities of 10 MW or less. (Maine Public Utilities Commission, 2014) The Community-Based Renewable Energy Pilot Program is a feed-in-tariff program that provides incentives to community-based projects in the forms of (1) above-market priced long-term contracts (up to 20 years) with a price cap of 10₵/kWh or (2) a 150% renewable energy credit (REC) multiplier. Projects choosing the first option must enter into long-term contracts with the T&D utility in whose service territory the project is sited. (Maine Public Utilities Commission, 2014) So far, no projects have chosen to take advantage of the REC multiplier option. The program initially had a 25-MW utility-specific cap, which was removed pursuant to P.L. Ch. 434 in 2014. The 50-MW overall program was kept, although there is insufficient space under the 50-MW cap for additional projects.[47] To date, no solar projects have participated in the long-term contract aspect of the program. Pursuant to P.L. Ch. 329, the program is scheduled to expire on December 15, 2015.

Time-of-Use Rates

Maine's investor-owned transmission and distribution (T&D) utilities offer time-of-use transmission and distribution rates options to residential customers. (Emera Maine, 2014) (Central Maine Power Company, 2014).[48] In addition, CMP offers a time-of-use option on Standard Offer/Default generation service rates. The electricity prices for customers opting for these rate structures fluctuate based on the time of electricity use. Because Solar PV produces during peak periods, time-of-use rates may allow PV hosts to displace higher-than-average peak rates coincident with the time of peak production, yielding additional value for self-generating customers.

Interconnection Standards

The Commission adopted interconnection standards for small generators interconnecting to the grid in 2010. The standards were modeled after the 2006 Interstate Renewable Energy Council (IREC) guidelines. All T&D utilities are required to establish interconnection application and review procedures of customer-generator facilities in the following levels. Each level has different fees and technical screens.[49]

[47] In a decision issued in April 2014, the Commission noted that there were 49.992 MW of projects certified for the Community-Based Renewable Energy Pilot Program to-date. (Maine Public Utilities Commission, 2014)
[48] The Commission staff report that these rates are not fully developed, with many issues to be resolved to better reflect cost and value.
[49] The 2014 Freeing the Grid Report gave the Maine interconnection standard a B grade, recommending that the state clarifies on the dispute resolution process. (Interstate Renewable Energy Council; Vote Solar, 2014)

Overview of Solar Implementation Approaches Used in Other States

This section focuses on solar implementation approaches adopted in the five other New England States (Connecticut, Massachusetts, New Hampshire, Rhode Island, and Vermont), New York, and four states (Delaware, Maryland, New Jersey, and Pennsylvania) within the PJM territory. These locations are selected for their electric market structure (same or similar regional system operator structure, deregulated markets) and economic opportunity (driven by insolation, similar geography and land use pattern, and demographics).

Table ES- 4. Summary of Solar Implementation Option: "Rules, Regulations and Rate Design"

Subcategory	Implementation Examples	Description
Removing Institutional Barriers	Interconnection Standards	Regulations standardizing the requirements of integrating solar PV to the grid
	Solar Access Laws	Rules protecting customers' access to sunlight and solar development rights
	Business Formation/Financing Laws	Policies authorizing certain types of business models or market structures designed to lower the entry barrier and expand access to the solar market
	Permitting Simplification, Other "Soft-Cost Reduction" Strategies	A suite of strategies designed to reduce the non-equipment costs associated with various stages of solar PV development
Building Codes	Solar-Ready Building Standards, Zero-Energy Capable Home Standards	Various building standards that (i) regulate orientation, shading, and other siting- and construction-related criteria; or (ii) support "plug-and-play" PV system configurations
Tax	Property Tax Exemption or Special Rate	Property tax relief to property owners installing solar PV
	Sales Tax Exemption	Tax relief exempting system owners from paying sales taxes for PV system equipment
	Property Tax/Payment in lieu of taxes (PILOT) Standardization or Simplification	State policies designed to limit community-by-community variations in property tax and PILOT rules; designed primarily to remove uncertainty

Grid Modernization	Policies Enabling Microgrids, Smart-Grid and Other DG-Friendly Grid Architecture	Policies designed to promote installations of DG-friendly technologies and grid architecture; aim to ease interconnection and advance implementation of solar PV
Rate Design	Time-Varying Rates, Rate Design, Fixed Charges and Minimum Bills	Cost-based utility rate design or rate structures designed to provide a correct or supportive price signal for the installation and operation of solar generation facilities

Table ES- 5. Summary of Solar Implementation Option: "Industry Support"

Implementation Examples	Description
Incentives for Companies, Technology Development, or Economic Development	Funding mechanisms designed to provide incentives for in-state solar businesses; allocated from the state budget, RPS alternative compliance payments, RGGI proceeds and/or public good funds
Local Content Bonus Or Mandate	Incentives or requirements that give preference to projects supporting in-state investment
Customer Acquisition Cost Reduction	Strategies leveraging scale economies or other measures to increase solar participation at a lower cost
Outreach/Education/Public Information/Voluntary Market Encouragement	Strategies designed to increase customer awareness of solar technology, voluntary and compliance solar markets, and solar funding and financing options
Public Sector Leadership and Demonstration	State or local initiatives, such as demo projects on public properties or statewide PV goals
Creation of Public Good Funds to Support Solar Programs/Policies	Policies establishing funds collected from ratepayers through utility bill surcharges; designed to provide long-term funding for solar incentive programs
Installer/Inspector Training and Certification	Training and certification programs designed to build a qualified local solar workforce

summarizes which of the identified implementation options has been adopted in each state. The rows describe the implementation approaches within each category, with a column for each state. An "X" indicates when a state has adopted a version of the associated implementation approach.

The remainder of this section qualitatively characterizes each implementation option. We selected a list of implementation approach characteristics guided by a literature review of solar implementation best practices. This list was designed to provide a clear and transparent layout for identifying and contrasting the characteristics of each implementation option, as well as to present a comprehensive understanding of the interactions among different implementation options and constituent groups. Most options are characterized as follows:

- **Implementation Option Overview** – Provide general background of implementation approach, including typical objectives and target market, such as what types of solar projects (e.g. customer sectors, system sizes, technologies, etc.) the approach typically targets/supports.
- **Key (or interesting) Structural Variations**
- **Impacts on Different Stakeholder Groups**
- **Implementation Issues**
- **Interactions with Other Implementation Approaches** – Identify whether there are implementation options that are typically complimentary, commonly considered as alternative or mutually-exclusive or conflicting options.

Table 39 – Solar Implementation Options Adopted in Other States

Category	Subcategory	Implementation Examples	CT	MA	NH	RI	VT	NY	DE	MD	NJ	PA
Instruments Used to Incentivize Solar	Direct Financial, Up-front Incentives (nameplate capacity-based or denominated)	Grants, Rebates, or Buy-Downs	X	X	X	X	X	X	X	X	X	X
	Direct Financial, Performance-Based Incentives (PBIs) (energy-based or denominated)	Feed-In-Tariffs, Standard Offer PBI Contracts or Tariffs, or PBIs (RECs, Energy, or Capacity)	X			X	X	X	X			
		Competitive Long-Term PPAs	X			X	X	X	X		X	
		Long-Term Value of Solar Tariffs										
		Technology-Specific “Avoided Costs”					X					
	Production Tax Incentives	Production Tax Credits								X		
	Demand-Pull/Solar Minimum Purchase Mandates	Renewable Portfolio Standards (RPS)	X	X	X	X		X	X	X	X	X
		Solar Set-Asides in RPS (SREC markets)		X	X				X	X	X	X
	Net Metering	Net Metering Crediting Mechanism	X	X	X	X	X	X	X	X	X	X
		Virtual Net Metering Crediting Mechanism	X	X	X	X	X	X	X	X	X	X
		Community-Shared Solar		X	X		X		X			
Financing Enabling **Policies**		Solar Loan Programs (Non-Subsidized or Indirectly Subsidized)	X	X	X			X	X	X	X	
		PACE Financing	X	X	X	X	X	X		X	X	
		Green Bank – Institutions and Suite of Other programs	X					X				

Category	Subcategory	Implementation Examples	CT	MA	NH	RI	VT	NY	DE	MD	NJ	PA
		Utility Ownership	X	X			X					
		Solar Lease and/or Third-Party Ownership Enabling Policies or Eligibility in Other Policies	X	X	X	X	X	X	X	X	X	X
Rules, Regulations and Rate Design	Removing Institutional Barriers	Interconnection Standards	X	X	X	X	X	X	X	X	X	X
	Tax	Property Tax Exemption or Special Rate	X	X	X	X	X	X		X	X	
		Sales Tax Exemption	X	X		X	X	X		X	X	
Industry Support		Local Content Bonus Or Mandate	X	X								
		Customer Acquisition Cost Reduction	X	X		X		X				
		Public Good Funds to Support Solar Programs/Policies	X	X	X	X	X	X	X	X	X	X

Instruments Used to Incentivize Solar

Incentives commonly used as vehicles to incentivize distributed solar PV include a suite of implementation options aimed at changing market or economic decision making by (i) creating market demand, (ii) removing financing barriers, and/or (iii) lowering installation costs for solar PV. (Doris, 2012). These options include direct and indirect financial incentives targeted at capacity development (i.e. Capacity-Based Incentives) or electricity production (i.e. Performance-Based Incentives). Incentives can also be offered as tax benefits credited according to system costs (i.e. Expenditure-Based Tax Incentives) or generation (i.e. Production-Based Tax Incentives). Mandates creating a demand-pull (i.e. renewable portfolio standards/Solar Minimum Purchase Mandates) for solar PV are also a form of incentives.

Direct Financial, Up-Front (a.k.a Nameplate Capacity-Based or Denominated) Incentives

Grants, Rebates, or Buy-Downs

Direct, up-front incentives, including grants, rebates and buy-downs, compensate or incentivize generators in proportion to installed system capacities. The primary objective of these implementation approaches is to reduce the up-front cost of PV installations, hence, lowering the entry barrier to solar development. Sometimes called “investment incentives,” these incentives differ from “performance incentives” because they are based on system initial size and investment, and are not contingent on performance. Typically, front-end payment policies are targeted to small- and medium-scale systems installed by residential and commercial and industrial (C&I) customers, where up-front cost is a great barrier. (Bird, Reger, & Heeter, 2012). Unlike tax-based incentives, cash incentives are available to entities with no tax appetite, such as municipalities and non-profit organizations. (DSIRE Solar Policy Guide: A Resource for State Policymakers, 2012).

Typically, up-front payment programs operate on a first-come, first-served basis for eligible installations until the allocated funding is fully subscribed. The incentive levels, nominally based on the installed (nameplate) capacity of the solar system (i.e. $/kW, usually measured at DC), are administratively-determined and known to eligible customers in advance. These programs can be funded with various mechanisms. Some common funding sources include state budgets (i.e. tax revenues), RPS Alternative Compliance Payment proceeds or public good funds (a.k.a. system benefit charge (SBC)-based funds). The latter two are funded by utility ratepayers.

There are several key design features to be considered when implementing an up-front incentive program:

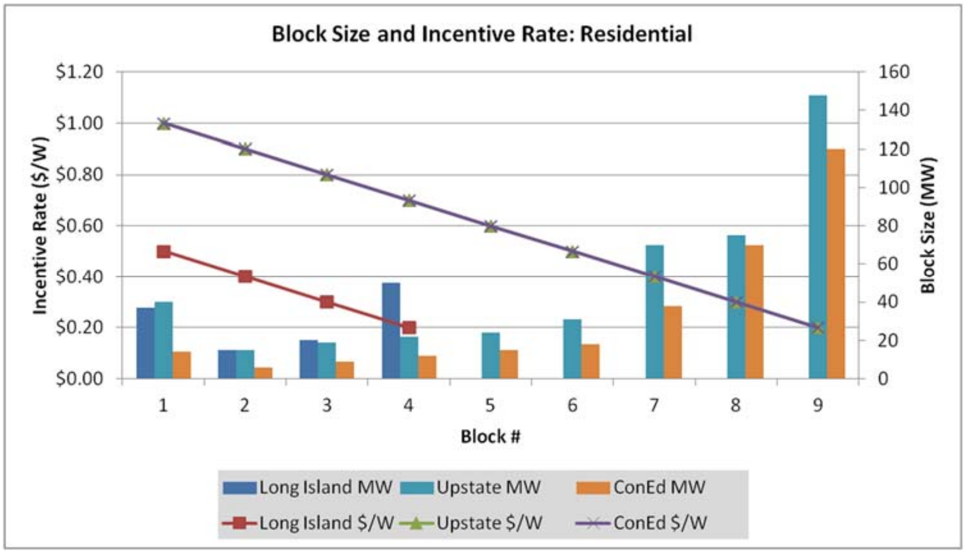
- **Program Blocks –** One issue with incentive programs operating on a first-come, first-served basis with limited budgets is a lack of predictability of funding availability. It is often challenging for developers to predict when the funding will be fully subscribed, especially in situations where applications for incentives outpace program budgets. Such an unstable start-stop cycle is especially challenging for large system owners, whose project development requires much longer planning time. (DSIRE Solar Policy Guide: A Resource for State Policymakers, 2012) This issue is especially prevalent where solicitation is infrequent. States can instead distribute program budget to multiple enrollment blocks and accept applications for block funding multiple times a year. This approach adds transparency and predictability to incentives over a longer period of time. Massachusetts' Commonwealth Solar II Rebate Program and New York's MW Block Program both operate under this model.

- **Performance Guarantees –** Front-end payments support the development of new capacity, but cannot guarantee actual energy production. It is a common concern that capacity-based incentives could not prevent poor system performance driven by improper installations or inadequate operation and maintenance (Bird, Reger, & Heeter, 2012), and in the absence of measures to encourage good performance, may actually incentivize poor performance. States can implement performance guarantees in their incentive programs, such as requiring equipment warrantees, establishing installer qualification requirements mandating inspections, etc. The New Hampshire Public Utilities Rebate program requires system owners to provide installer information, estimated optimal PV production, production loss from shading, and other system details. (New Hampshire Public Utilities Commission, n.d.). Some states have developed hybrid approached in which a portion of an incentive is distributed as a performance-based incentive (described below) during the first few years of operation. Some other states, such as California and New York, use a hybrid approach called an expected performance-based incentive, or EPBI, which is provided up-front like other incentives described in this subsection, but ultimately dependent on performance like PBIs described in the next subsection, with the potential for incentive 'claw-back' in the event of underperformance.

- **Geographic Balance –** Non-competitive standard incentives typically do not stimulate geographic diversity in project development. The New York MW Block Program addresses this issue by creating different incentive rates for different utility territories (e.g. higher incentive levels for New York City and upstate, lower incentive levels for Long Island). This mechanism allows more equitable allocation of incentive funding based on the difference in project development costs driven by geographic constraints (e.g. solar insolation, building structures, etc.). It also incentivizes solar development where distributed generation is needed most, such as areas with distribution constraints or high load density.

- **Incentives Adjustment –** It can be challenging to set upfront incentives correctly in a dynamic market. Good up-front payment programs should be responsive to changing market dynamics (e.g. demands, electricity prices, project economics, and market diversity, etc.). For example, the Massachusetts Clean Energy Center (MassCEC) can adjust the incentive level for each successive enrollment for the Commonwealth Solar II Rebate program to account for changing market interests, decline in solar technology costs and other market conditions. The MassCEC also incorporates incentive adders (e.g. Massachusetts Company Component adder, Natural Disaster Relief adder and Moderate Home Value and Moderate Home Income adder), which award certain customer classes or project types with extra incentives. (Massachusetts Clean Energy Center, n.d.) Some states implemented capacity-based incentive programs with declining incentive schedules to reduce reliance on incentives, both following and encouraging reduced solar technology cost over time. The following graphs demonstrate the declining incentives under New York's MW Block Program:

Figure 33 – New York MW Block Program Declining Incentives (Residential)[50]



Compared to other incentives, capacity-based programs have a much more front-loaded budgetary demand. (Bird, Reger, & Heeter, 2012). Unlike tax incentives or performance-based incentives, which are typically funded by ratepayers, rebates, grants and buy-downs require an explicit funding mechanism, often appropriated from the state budget or established through a ratepayer SBC fund. This factor often makes up-front payment policies less appealing to policymakers, as demand can outstrip the funding source and bring a growing market to a halt. It also makes more rebates, grants and buy-downs programs more susceptible to raids when state budget is short, as evidenced in Connecticut and New Hampshire in recent years.[51] (DSIRE Solar Policy Guide: A Resource for State Policymakers, 2012)

[50] (The NY-Sun Initiative, 2014)

[51] In June 2013, the Connecticut legislature passed a budget bill that would transfer the $5 million in Regional Greenhouse Gas Initiative funding and $30.4 million in Clean Energy Finance and Investment Authority funding to the General Fund to help balance the budget for fiscal years 2014 and 2015.

Direct Financial, Performance-Based Incentives (PBIs)

PBI Feed-In-Tariffs, Standard Offer PBI Contracts or Tariffs

Standard offer performance-based incentives (PBI) reward generators for actual solar energy production (i.e. kWh) at a known rate over a fixed period of time. This approach provides generators with a predictable revenue stream, reducing financing risks. Typical standard offer PBI policies involve T&D utilities purchasing energy and/or RECs from generators through multi-year term contracts or tariffs at a predetermined $/kWh rate or rate schedule on a first-come-first-served basis. (New York State Energy Research and Development Authority, 2012). The contract/tariff rates are usually administratively-determined based on market research and economic analysis, although they can also be based on a competitively-derived price (as is the case for Connecticut's Small ZREC program, which sets prices at 110% of the weighted average of winning bids from Medium ZREC auctions). (Connecticut Light & Power Company; United Illuminating Company, 2011).They can be fixed over time, increased at a predetermined escalator, or indexed according to inflation, spot electricity prices and other factors. Utilities can use the purchased energy, capacity and/or RECs to meet their obligations or resell the attributes at spot market prices. In the latter option, utilities can recover the difference between the spot prices and the contract/tariff prices from ratepayers. Standard offer PBIs can be implemented with many different features, such as purchase and dispatch requirements and contract terms, designed to achieve different implementation objectives. (New York State Energy Research and Development Authority, 2012). A Feed-In-Tariff (FIT) is a globally popular form of a standard offer PBI policy that guarantees generators access to the electricity grid over a fixed term.[52]

Standard offer PBIs are available to most customer classes and system sizes, although some states have separate competitive procurement procedures for larger commercial-scale systems. Standard offer PBIs are especially attractive to small residential and C&I customers as they typically have low barriers to participate (New York State Energy Research and Development Authority, 2012) and have minimal transaction costs. To prevent large projects developed by more sophisticated players from crowding out smaller systems, most states allocate fixed budgets or capacities to different customer and or system size blocks to protect residential and small C&I customers and support market diversity.

Standard offer PBI programs can be implemented with different price setting and payment models, described as follows:

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[52] For more information on FITs, see:

- Rickerson, Wilson H., Janet L. Sawin and Robert C. Grace, *If the Shoe FITs: Using Feed-in Tariffs to Meet U.S. Renewable Electricity Targets*, The Electricity Journal, Vol. 20 (4), May 2007; or
- Grace, Robert, Wilson Ricerson, Kevin Porter, Jennifer DeCesaro, Karin Corfee, Meredith Wingate and Jonathan Lesser, *Exploring Feed-in Tariffs for California: Feed-In Tariff Design and Implementation Issues and Options.* California Energy Commission. Publication number: CEC-300-2008-003-F, Sacramento, CA, November 2008.

- **Standard Offer PBI Price Setting –** Standard offer PBI prices can be determined in multiple ways. Levelized cost of solar generation (e.g. Rhode Island Renewable Energy Growth Program) and avoided costs (of solar e.g. Vermont Sustainably Priced Energy Enterprise Development Program) are two commonly used factors for calculating standard offer prices. Standard offer prices can also *value*-based, i.e. represented the value of solar generation to the society and/or utilities. A fourth option is a competitively-derived price approach, which uses the prices from a prior auction separate from the standard offer program to inform the standard offer incentive levels (e.g. Connecticut Small Zero Emissions Renewable Energy Credit Program[53] (Couture, Cory, Kreycik, & Williams, 2010)

- **Payment Structure –** Standard offer incentives can be credited with different payment structures. A typical approach is to issue the incentives as direct payments under multi-term contracts or tariffs. Another approach, typically targeted to residential and small C&I customers, is to pay the incentives as a bill credit to the generators. Rhode Island's Renewable Energy Growth program applies the PBIs first as bill credit on a residential customer's bill. The difference of the total PBI payment under the Renewable Energy Growth program and the value of the credit to the generating customer's bill is paid as a direct payment to the generator.

Standard offer PBIs provide generators with revenue predictability, reducing financing risks. While they do not spur competition among projects, they are generally understood to create market scale and stability which drives competition and innovation further up the value chain (i.e. shifting the basis of market competition from generation price to equipment price and installation labor cost). (KEMA, Inc. , 2009). Long-term standard offer contracts or tariffs which procure energy and RECs at a fixed price also help utilities hedge against fuel price volatility. The ratepayer impact of standard offer PBIs is mixed. While standard offer PBIs can reduce the cost of solar PV and increase electricity price certainty, if not set with certain well-understood cost-containment mechanisms limiting quantity or cost, there is a risk of oversubscription if the prices are set too high, potentially triggering undesirable rate increases.[54] (Kreycik, Couture, & Cory, 2011). Additionally, there are several implementation issues to be considered when implementing standard offer programs:

- **Price Setting –** PBI price must balance the drive for investment and ratepayer impacts. Incentive levels that are set too low may not support market growth. Incentive levels that are set too high could over-stimulate the market and lead to oversupply of solar PV and undesirable rate impacts. (Grace, et al., 2008)

- **Market Responsiveness –** Standard offer PBIs are generally considered to lack market responsiveness. These programs lock in electricity prices over multiple years, and in some cases, over a decade. As a result, they typically cannot react to market conditions and other external

[53] The Connecticut Small ZREC (systems up to 100 kW) tariff rate is derived using 110% of the weighted average bid price from the previous Medium ZREC (100 – 250 kW) solicitation.
[54] Spain's feed-in tariff is the classic example of this risk. (Kreycik, Couture, & Cory, 2011).

factors, such as policy changes. "Must-buy" provisions under long-term FITs can create additional inflexibility by prohibiting utilities from adjusting their purchases according to demands and electricity prices. (Couture, Cory, Kreycik, & Williams, 2010)

- **Drive for Project Cost Reduction –** By providing uniform incentives for all projects, standard offer PBI provides little drive for project competition, which push downward pressure on project pricing.

Standard offer PBIs for solar are sometimes paired with RPS policies (or operate within them), where utilities can use the purchased electricity and/or solar RECs toward RPS obligation compliance or resell the RECs to RPS obligated entities. FITs can sometimes serve as an alternative option to net metering. Instead of allowing solar customers to reduce retail load with onsite generation, utilities can purchase all electricity through FIT arrangements.

Competitively-Procured Long-Term Power Purchase Agreements (PPAs) or Tariffs

Six of the states studied here have implementation options that establish competitive solicitation process for long-term power purchase agreements or tariffs for solar PV and other distributed renewable generation. Typically, these options require a procurement entity, usually a T&D utility (but sometimes a separate central administrator), to purchase either RECs or a combination of RECs, solar energy and capacity through power purchase agreements or tariffs at fixed prices most often over a 10- to 25-year term. In most of the options discussed here, T&D utilities are the procurement entity and are responsible for the PPA or tariff payments. Competitive long-term power purchase agreements or tariffs are often paired with RPS to provide long-term added certainty to REC prices and supply availability, as well as to ensure that at least a portion of RPS supply is sourced locally (bringing local economic benefits). T&D utilities can use the purchased RECs toward their own RPS obligation or resell the RECs, energy, and/or capacity as applicable into the market at spot prices, passing the difference between the spot price and the PPA/tariff price through to distribution ratepayers. Competitive long-term PPA or tariff programs are usually targeted to larger distributed generation or utility-scale installations. Residential and small commercial and industrial (C&I) customers typically are targeted with non-competitive programs, which have less sophisticated procedures and lower transaction costs. To enable smaller customers to participate in competitive programs, some states allow installers to participate as aggregators on behalf of multiple small customers and bid in aggregations.

By providing long-term price certainty and revenue stability, long-term PPA or tariff policies lower the barrier of financing solar PV, which in turn enable solar projects to attract financing. Creditworthy PPAs or tariffs increase developers' ability to obtain low-cost financing and provides reasonable revenue stability. This reduces the required incentive for solar development in the long-run. Further, long-term PPA or tariffs which purchase energy allow T&D utilities to hedge against fuel volatility of their distribution customers. As a result, long-term PPAs or tariffs put downward pressure on solar subsidies, hence reducing ratepayer impacts in the long-run.

Competitive long-term PPA or tariff policies can be implemented with various design features:

- **Solicitation Classes -** To foster market diversity and equity, or to differentially incentive favored subsectors of the market, some long-term PPA or tariff programs are divided into multiple solicitation classes for different system sizes, ownership types and other project types. This approach has been taken in Connecticut, Rhode Island and Delaware, for example. The following table summarizes the solicitation classes available in each program:

Table 40 – Solicitation Classes in Connecticut, Rhode Island and Delaware's Long-Term PPA/Tariff Programs

State	Program	Solicitation Classes
Connecticut[55]	Zero Emission Renewable Energy Certificate Program	• Small ZREC (Systems up to 100 kW)[56] • Medium ZREC (Larger than 100 to Smaller than 250 kW) • Large ZREC (250 to 1,000 kW)
Rhode Island[57]	Renewable Energy Growth Program	• Small Solar I – Owner/Host Financed (1 to 10 kW) • Small Solar I – 3rd Party Financed (1 to 10 kW) • Small Solar II (11 to 25 kW) • Medium Solar (26 to 250 kW) • Commercial Solar (251 to 999 kW) • Large Solar (1 to 5 MW)
Delaware[58]	SREC Procurement Program	• N1 – New Projects (<30 kW) • N2 – New Projects (31 – 200 kW) • N3 – New Projects (201 – 2,000 kW) • E1 – Existing Projects (<30 kW) • E2 – Existing Projects (30 – 2,000 kW)

- **Price vs. Volume Limited –** Many programs establish volumetric targets, while some are budget-limited. For example, the program can be capped at a pre-determined capacity target (e.g. Rhode Island's Renewable Energy Growth program) or a percentage of the state utilities' peak retail loads. Alternatively, a program can operate subject to a pre-determined budget in each enrollment (e.g. Connecticut Low Emission Renewable Energy Certificates/Zero Emission Renewable Energy Certificates Programs and New Hampshire Commercial & Industrial RFP for Renewable Energy Projects). The volume procured therefore varies with price. One determinant of the approach is the source of funds: an SBC-fund or similar cash source of budget will often dictate a budget-limited

[55] (Connecticut Light & Power, n.d.)
[56] The Connecticut Small ZREC solicitation does not operate as a competitive program. However, the tariff rate is competitively-derived using the weighted average bid price from the previous Medium ZREC solicitation.
[57] (Rhode Island Distributed Generation Board, 2014)
[58] (Delaware Sustainable Energy Utility, 2014)

approach, while a program that results in regulator-approved pass-through of costs or benefits to ratepayers allows a fixed quantity target to be pursued without a specific budget cap.

- **Solar-Only vs. Multi-Technology Competition –** In most instances discussed herein, procurement pits solar PV installations against each other, often within subclasses as noted above. Competitive procurement of utility-scale solar head-to-head with other types of renewables has been common in California and the southwest for several years due to much higher capacity factors and scale economies than available in the Northeast. However, utility-scale solar could be nearing the point of being able to compete head-to-head with other renewables resources in all-renewables long-term contract procurements in the northeast, as evidenced by recent selection of a 20 MW utility-scaled project under Connecticut's Public Act 13-303 Section 6 RFP at the end of 2013 (it is too early to know whether the bid price is viable, as the project has until the end of 2016 to reach commercial operation).

There are several common implementation issues with long-term PPA or tariff procurement policies:

- **Potential Violation of Federal Power Act –** There have been several lawsuits in Maryland, New Jersey and Connecticut regarding the legality of state-administered long-term energy contract programs. (PPL Energyplus, LLC, et al. vs. Douglas R. M. Nazarian, 2013) (PPL Energyplus, LLC vs. Robert M. Hanna, 2013) (Allco Finance Limited vs. Robert Klee, 2014). Stakeholders argued that such programs overstep the Federal Energy Regulatory Commission's jurisdiction by establishing wholesale energy rates. Both Maryland and New Jersey's long-term contract programs were invalidated as a result of the legal actions. The Connecticut Section 6 procurement program was found not found by the courts to be preempted by the Federal Power Act, although that ruling is being appealed (Allco Finance Limited vs. Robert Klee, 2014).
- **Project Attrition –** Competitive procurements are commonly characterized by a modest to substantial rates of project attrition, driven by speculative bidding and sometimes excessive administrative burden and regulatory and utility delay, which can be exacerbated by inflexible completion milestones. These factors are exacerbated when solicitations are infrequent or there are low or no bid security requirements. When such conditions hold, sophisticated developers could submit an inventory of bids and then pick and choose which selected projects to develop.
- **Procurement Frequency** – In contrast to procurement mandates (like RPS tiers) or standard offers, which allow for a relatively steady stream of sales, design, financing and installation workflow that is conducive to establishing long-term jobs, episodic procurements represent bursts of activity that are difficult to staff for, often leading to short-term jobs and greater use of mobile labor. We have observed that infrequent procurement events tend to exacerbate speculative bidding, as the sparse market opportunities encourage bidders to offer immature projects with greater completion risk (rather than forego all opportunities until the next procurement events). Procurement frequency varies. For example, the Rhode Island DG Standard Contract program procured three times per year while the Connecticut ZREC solicitations are only offered once per year. Further, with competitive procurements for customer-sited generation, there can be significant frustration as hosts go through extensive internal decision-making efforts to decide to commit to a project, only to have their developer fail to win a bid, leaving them with no project (and if procurements are less frequent, a

long period before getting another shot at a bid, often requiring renegotiation of PPA or lease transaction to make a project viable). (Connecticut Conference of Municipalities, 2014)

- **Security Requirements** – To address high rates of project failure and speculative bidding, some states have considered implementation approaches that create higher barriers of entry (security requirements as well as project milestones) while allowing a degree of flexibility to address unforeseeable factors that may cause delays. (Belden, Michelman, Grace, & Wright, 2014). The downside of raising the bar to entry, however, is reduced participation and price competition.

Long-Term Value of Solar Tariffs[59]

A Value of Solar Tariff (VOST) is a net energy metering (NEM) tariff design that incorporates value of solar analysis in setting the credit value for customer generation from solar energy facilities. Under traditional net metering, the customer's retail rate is the rate applied to calculate the bill offset amount – an arbitrary proxy for the value of the generation. Under a VOST, the calculated value of solar is used to calculate the bill offset amount created by solar generation, a truer and more transparent incentive. As with net metering, many different modifications, adjustments, and options are also possible under a VOST—such as the credit rate for excess energy generation, the netting period for calculating offsets, the extent to which the credit can offset certain fixed charges, and the period over which the offset rate is stabilized. The VOST seeks to improve on traditional NEM by using an offset credit rate that is empirically derived through a full avoided cost methodology.

In the two places where the tariff has been implemented so far, the City of Austin (Texas) and the State of Minnesota, the tariff was expressly designed to be modeled on a basic net metering structure and to avoid a sale by providing only an offsetting credit for customer generation. In this regard, VOST and NEM structured in this way[60] differ from Feed-In Tariffs and so-called Buy-All-Sell-All rates. The VOST approach has been targeted at small customers, both residential and commercial, seeking to offset their electricity bill associated with consumption of energy.

[59] For more information on Value of Solar Tariff, see:

- The ICER Chronicle – A Focus on International Energy Policy "Chapter VIII – The Value of Solar Tariff: Net Metering 2.0:" http://www.rabagoenergy.com/files/icer-chronicle-rabago-vos-article-131220---extract.pdf.
- Minnesota Value of Solar: Methodology: http://mn.gov/commerce/energy/images/MN-VOS-Methodology-FINAL.pdf.

[60] Skadden, Arps, Slate, Meagher & Flom LLP prepared a legal memo for The Alliance for Solar Choice (TASC) regarding the tax implications of feed-in-tariffs and value of solar tariffs in August 2013. It argued that FIT and VOST frameworks require the sales of all customer generation, and hence, could jeopardize a customer's ability to receive certain tax credits that have on-site consumption threshold. (The Alliance for Solar Choice, 2013). TASC's argument presumes that VOST is set up as a "front of the meter" rate and system, while Austin and Minnesota both intended for the VOST to be a "behind-the-meter" netting system. Hence, it can be argued that VOST does not constitute a buy-all-sell-all arrangement. Rather, it is an offsetting credit for onsite generation.

The VOST as applied in these instances was designed to preserve the benefits of Federal residential solar tax credits and state-level property tax exemptions for solar equipment. A VOST is designed to fairly value customer generation (or, perhaps more accurately, to compensate generation based on an assessment on its administratively-determined value), and its advocates argue that it can nominally keep the utility whole for the cost of distribution and supplemental power services (we note that this could be the case so long as the portion of the VOST not readily avoided or monetized by the utility are recovered from ratepayers). The VOST approach serves as a model for valuing other distributed energy resources, such as energy storage, demand response, and ancillary services. The VOST requires a value of solar analysis, which in turn requires data and the development of a methodology. The VOST should be regularly updated to capture changes in avoided costs. Like traditional avoided cost proceedings, this process is best conducted with public participation and regulatory oversight. The VOST can be adopted as an optional alternative to traditional net metering, or as a substitute. In some cases, utilities may not collect the data or collect it in a form that allows full calculation of the value of solar. There may be ongoing disagreements about the best way to calculate some value components.

Technology-Specific "Avoided Costs"

Standard offers or feed-in tariffs have been challenged as violating the division of Federal versus state authority pursuant to the Federal Power Act (Hempling, Elefant, Cory, & Porter, 2010), but FERC has held that the Federal Public Utility Regulatory Policies Act (PURPA) allows purchase of electricity from a particular source of energy under a multi-tiered avoided-cost structure through a standard offer program at or below the specific technology's avoided-costs. (Cal. Pub. Util. Comm'n Et. al, (July 15, 2010)) (Cal. Pub. Util. Comm'n Et. al, (Oct. 21, 2010)) States or non-regulated utilities can establish their own methodology for determining the technology-specific avoided costs, provided that the method complies with the criteria in PURPA and is non-discriminatory to co-generators or small power producers. (Burns & Rose, 2014). It is important to recognize that technology-specific avoided costs are a federal rate concept. By definition, it does not account for non-jurisdictional avoided costs, such as RPS compliance costs.

Technology-specific avoided costs provide an improvement to the one-size-fits-all incentive rate setting method, allowing more accurate determination of the cost of each renewable technology. They have been applied as standard offer prices, or as ceiling prices under which competition can take place. Among the states considered in this section, Vermont is an example that explicitly uses technology-specific avoided costs, characterized as such, as an approach for setting standard-offer rates. The state's Sustainably Priced Energy Enterprise Development (SPEED) Standard-Offer program operates as a centrally-administered competitive procurement. The contract price for each technology block is capped at the avoided costs for that specific technology. For solar PV, the administratively-set avoided cost schedule is set at a fixed rate throughout the contract period. Bidders are required to propose a single price for the contract period that is no more than the administratively-set solar avoided cost. For other technologies, bidders can propose an escalating price schedule to reflect inflation. (VEPP Inc., 2014)

Indirect Financial Incentives

Emissions Markets

Emissions markets policies are market-based emission cap-and-trade programs usually implemented in a regional or broader scale. A typical emission markets program includes a declining emission target schedule for the power sector, with responsibility for meeting that cap apportioned to generators according to an administratively –determined process. Power plants from participating states can demonstrate compliance by purchasing emissions allowance from their states. The net effect is an increase in the price of electric energy resulting from generators including this variable cost in their wholesale energy market bids, indirectly increasing the value realized per MWh sold from non-emitting generation, like solar PV. It is important to note that emission allowance values represent the cost of program compliance, denominated in dollars per allowance or ton of carbon dioxide. This compliance cost may or may not be related to the value of avoided emissions in terms of avoided environmental damages. As such, the price of an emission credit should not be assumed to represent the "value" of non-emissions from non-emitting resources. Proceeds from the sales of emissions allowance are used to support state renewable energy and energy efficiency initiatives. The Regional Greenhouse Gas Initiative (RGGI) is an example of such approach. Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, Vermont, New York, Delaware, and Maryland are all current members of RGGI.[61] (Regional Greenhouse Gas Initiative, n.d.)

Expenditure-Based Tax Incentives

Investment Tax Credits

Investment Tax Credits (ITC) are capacity denominated tax incentives. Typically, they are direct deductions in tax liability associated with the cost of purchasing and installing solar systems. To take advantage of an ITC, the owner must have a 'tax appetite' (and is thus not available to government and non-profit entities) and the investment must be 'at risk'. A 30% ITC for DG solar is currently offered at the federal level; after 2016, the 30% ITC expires, while a 10% commercial ITC (unavailable to residential-owned systems) will remain thereafter. (U.S. Department of Energy, 2014). Some states have implemented ITCs at the state level. For instance, Massachusetts has a residential solar ITC, which applies a 15% credit, up to $1,000, to a system owner's state income tax for the net expenditure of a solar PV facility installed on the system owner's primary residence.[62] Under the Massachusetts ITC program, excess tax credits can be applied to subsequent year for up to three years. (DSIRE, 2014).

[61] New Jersey was a RGGI member until 2011.
[62] The system owner can be a tenant of the property.

Production Tax Incentives

Production Tax Credits

Production Tax Credits (PTC) are tax incentives offered based on, and contingent on, electricity production (i.e. $/kWh), and as such, are akin to performance-based incentives (and could readily be categorized thereunder). Like an ITC, to take advantage of an ITC, the owner must have a 'tax appetite' (and is thus not available to government and non-profit entities) and the investment must be 'at risk'. It is not a common implementation approach at the state level. Maryland is the only state of those features here that offers Clean Energy PTC. The program has a credit floor, which sets a minimum amount of PTC payment a system needs to yield in order to be eligible for the program. The price floor indirectly eliminates any systems smaller than 20 kW to participate. (Administration, n.d.)

Demand-Pull/Solar Minimum Purchase Mandates

Renewable Portfolio Standards (RPS) and Solar RPS Tiers (Set-Asides)

All ten states discussed in this Section with the exception of Vermont[63] have active Renewable Portfolio Standards. RPS mandates typically require electric suppliers to meet a minimum percentage of their annual retail loads with renewable energy by purchasing and (for states considered here) retiring renewable energy certificates (RECs).[64] When the obligation is places on electricity suppliers, the cost of RPS compliance is embedded in the cost of electricity.[65] While solar PV is nominally eligible for all RPS, it is generally not competitive enough against other resources in technology-neutral RPS policies, especially in the northeast. As a result, some states have incorporated explicit tiers or set-asides (sometimes referred as carve-outs when they explicitly constitute a subset of another RPS tier) within the RPS for solar PV or distributed generation. Set-asides policies stimulate demand for, and thus investment in, specific technologies (in this case, solar PV) within the RPS that would otherwise not be supported due to cost and other development constraints. Solar set-asides require that a specified portion of the RPS be met with solar generation, typically (in the northeast competitive markets) through use of solar renewable energy certificates (SRECs) as a distinct tier of an overall RPS requirement, often carved-out of a larger tier designated for new resources. Solar carve-outs are a widely-adopted implementation approach, most common in states with deregulated markets. As shown in the following map, of the states studied for this report, Massachusetts, New Hampshire, Delaware, Maryland, New Jersey and Pennsylvania all incorporated solar set-aside policies.

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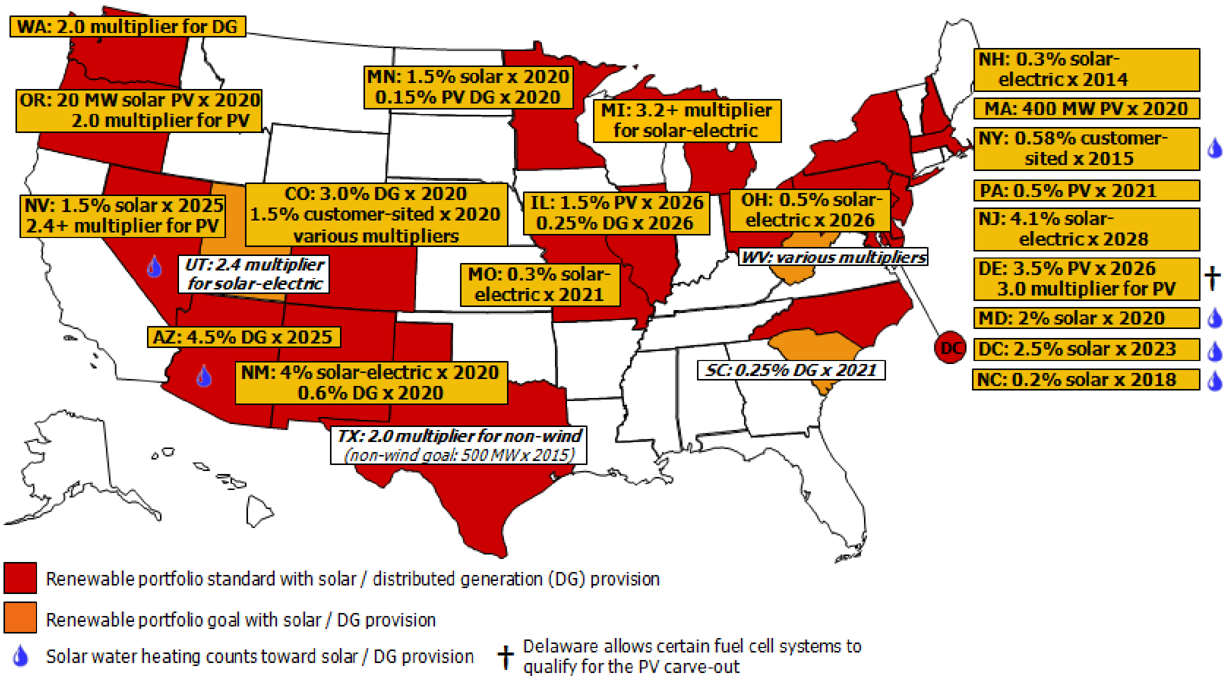
[63] Proposed RPS legislation, including a distributed generation tier, was filed in January of 2015, and appears to have significant potential for adoption.

[64] The exception is New York, where the RPS obligation is not placed on load-serving entities, but rather run by a centralized procurement entity, NYSERDA. Instead, generation attributes associated with production from systems driven by up-front incentives and competitively-procured long-term REC contracts are counted towards meeting state RPS targets.

[65] In the case of New York, or any state placing the obligation on the distribution company in an unbundled market, the costs are collected through a surcharge on distribution bills.

Figure 34 – States with Solar/DG Set-Asides Policies[66]



Solar set-aside policies are designed to provide additional incentive for solar development. The additional incentive is usually driven by higher price caps or Alternative Compliance Payment (ACP) levels relative to the Class I market. In order to track and encourage anticipated technology cost reduction, some states, such as Massachusetts and Maryland, have established declining ACP schedules that eventually merge with the "Class I" (undifferentiated) market. Alternatively, a credit multiplier approach, which increases the effective REC value ($/MWh) of solar generation relative to other Class I sources, is used. (DSIRE Solar Policy Guide: A Resource for State Policymakers, 2012). RPS and solar set-asides policies are sometimes paired with long-term contracts or tariffs to add price and supply certainty to the market. Under these embedded long-term procurements, T&D utilities may choose to solicit unbundled contracts for just the RECs (e.g. New Jersey and Connecticut) or bundled contracts for a combination of RECs, energy and capacity (e.g. Rhode Island). (Atlantic City Electric Co., Et. al, 2011) (SREC-Based Financing Program - Documents, 2011) . Attributes purchased through the long-term agreements can be used toward the utilities' obligations or resold to the spot market to be made available to RPS obligated entities.

Solar RPS set-aside policies support solar PV of all sizes and market sectors, although some states may choose to promote specific market sectors within the solar set-asides using additional eligibility requirements (e.g. system size caps, geographic location requirements, etc.) and differentiating

[66] (DSIRE Solar, 2014)

incentive mechanisms (e.g. Massachusetts' SREC factors). States can also adopt various design features to advance additional implementation objectives.

Key structural variations include:

- **Price Caps or ACP Levels –** Unlike the other states mentioned earlier, New Hampshire's solar carve-out (RPS Tier II) program has the same ACP level as its RPS Tier I. This design eliminates the main objective of set-asides policies, which is to stimulate solar investment by providing a higher level of incentives. The lack of additional incentives for solar compared to other technologies, coupled with the state's low ACP rates relative to the region provides little support for solar PV development in New Hampshire, and RECs from those PV installations are most often is sold into other New England markets with higher REC prices.[67]

- **Price-Support Mechanisms –** RPS target schedules are typically pre-determined by the legislature to achieve a specific overall quantity target over a period of time. In most cases, the targets can only be adjusted through legislation.[68] The lack of flexibility for solar set-asides to adjust with changing market conditions is a common concern. Several states, such as New Jersey, have observed drastic SREC price volatility over the years. (Belden, Michelman, Grace, & Wright, 2014). Both New Jersey (N.J. P.L. 2012, Chapter 24, 2012) and Maryland (Chapter 494, 2010) have accelerated their solar set-asides schedules through legislation in response to rapid market growth. With an eye towards mitigating SREC price volatility, and in particular prevent price crashes, in the absence of statutory authority to create a firm price floor the Massachusetts Department of Energy Resources implemented two strategies to add flexibility to its solar carve-out program. Massachusetts uses a unique supply-responsive demand formula that adjusts the demand targets at an annual basis according to the actual volume of past solar installations, ACP payments and market trends. The carve-out is further supported by a floor-price auction mechanism, which creates a soft price floor to limit SREC price variability. In years of market surplus, solar system owners can offer their unsold SRECs in a state-administered fixed-price auction at a pre-determined price of $285/MWh.[69] The auction is conducted in up to three rounds; if it does not clear in the first round, the life of SRECs purchases out of the auction are extended and the future demand is further ratcheted up to induce greater expected value for SRECs re-minted in the auction. This mechanism is a "soft" price floor because SRECs can be and sometimes are sold below the floor if buyers expect SREC prices to sink below the floor in the future, or if the floor price is expected to be realized from sale or re-minted SRECs in later years, discounted based on the time-value of money. (Massachusetts Department of Energy Resources, n.d.)

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[67] According the state's 2013 RPS Compliance Report, roughly 50% of the state's solar carve-out obligation is met by ACPs. (New Hampshire Public Utilities Commission, 2014) Most of New Hampshire's current solar development is facilitated by the state's solar rebate and competitive procurement programs, as well as Massachusetts' RPS Class I, which has a higher ACP level.

[68] In Rhode Island and New Hampshire, state regulators are authorized to adjust the RPS targets in the event of resource inadequacy.

[69] Buyers from the auction pay $300 per SREC, with the spread funding the cost of conducting the auction.

- **SREC Factor and Managed Growth Sector –** Massachusetts incorporated a SREC Factor mechanism under Phase II of its Solar Carve-out. This mechanism credits generation associated with specific market sub-sectors (defined by project types or sizes) at higher values (SREC/MWh), as shown in Table 41.

Table 41 – Massachusetts RPS Solar Carve-out Phase II Market Sectors and SREC Factor[70]

Market Sector	Generation Unit Type	SREC Factor
A	1. Generation Units with a capacity of <=25 kW DC 2. Solar Canopy Generation Units 3. Emergency Power Generation Units 4. Community Shared Solar Generation Units 5. Low or Moderate Income Housing Generation Units	1.0
B	1. Building Mounted Generation Units 2. Ground mounted Generation Units with a capacity > 25 kW DC with 67% or more of the electric output on an annual basis used by an on-site load	0.9
C	1. Generation Units sited on Eligible Landfills 2. Generation Units sited on Brownfields 3. Ground mounted Generation Units with a capacity of <= 650 kW with less than 67% of the electrical output on an annual basis used by an on-site load.	0.8
Managed Growth	Unit that does not meet the criteria of Market Sector A, B, or C.	0.7

- ***Limitations on Market Segments – Based on experiences with accelerated development of larger multi-MW scale systems triggering sudden surplus and volatility, desire for development diversity (i.e. maintaining opportunities for smaller, customer-sited installations) and the desire to steer development towards rooftops and locations with load and away from remote sites with other uses (such as agricultural land), states such as Massachusetts and New Jersey have acted to limit the aggregate capacity that can be developed in these segments.*** (Belden, Michelman, Grace, & Wright, 2014)***. For example, Massachusetts*** established a 'Managed Growth' sector (see Table 41), which includes ground-mounted utility-scale solar projects sited on greenfield sites. The aggregated target capacity is set, and capacity available to the Managed Growth sector is determined on an annual basis based on the volume of solar installations in other market sectors. This approach allows the state to control market growth and advance other implementation goals, such as promoting brownfield solar installation, residential and small-business solar installation and affordable housing solar projects. (MA 225 CMR 14.07, 2014)
- ***Who Bears the Obligation – Of the state's examined here, all but two place the RPS and SREC Set-aside obligation on load-serving entities. Exceptions include New York and Delaware. New York***

[70] (Massachusetts Department of Energy Resources, n.d.)

uses a 'central procurement' mechanism through which the New York State Energy Research and Development Authority (NYSERDA) runs solicitation programs funded by an SBC-like charge collected by the state's distribution utilities. Delaware places the RPS obligation on the state's distribution providers (Delmarva, DEC, and DEMEC). While we are not aware of an example, it is feasible that a distinct distributed solar PV tier obligation could be placed on distribution utilities while maintaining the RPS obligation on load-serving entities.

Our research and literature review have identified several concerns regarding the implementation of solar set-aside policies:

- **Potential Violation of Interstate Commerce Clause –** Most states have, in the process of developing their renewable energy implementation strategies, considered the local economic benefits an important driver. (Grace, Donovan, & Melnick, 2011) Some states have geographic requirement that limits their solar carve-out policies to in-state generation only. In several states, stakeholders have filed complaints or taken legal actions challenging the legality of "out-of-state exclusion" provisions in solar carve-out and other renewable policies on the ground of violation of the Constitution's Interstate Commerce Clause.[71] Thus far, there have been no successful legal challenges finding violation of the federal commerce clause. Nonetheless, states regularly take extreme care in crafting RPS mandates to avoid crossing this line, and crafting policies targeted at generation interconnected at the distribution level has been a commonly used approach. (Elefant & Holt, 2011)

- **Market Volatility –** Enhanced and expiring federal incentives, reduced solar installation costs and high SREC prices created a surplus of SRECs in New Jersey in late 2011 and early 2012. The rapid market growth was followed by a period of market stagnation as SREC prices plummeted in response to an oversupplied market. Volatility in the market creates revenue uncertainty and increases investment risks, raising the barrier for market-entry and undermining a stable environment for job growth. (Belden, Michelman, Grace, & Wright, 2014)

[71] In April 2010, TransCanada Power Marketing filed a civil lawsuit in Massachusetts District Court against the Department of Energy Resources and Department of Public Utilities, asserting, among other issues, that the Massachusetts Solar RPS carve-out, which requires load serving entities to meet solar specific RPS targets by purchasing SRECs from in-state generators is unconstitutional and in violation of the Interstate Commerce Clause. TransCanada ultimately reached a Partial Settlement Agreement with the Commonwealth of Massachusetts and the original suit was dismissed. (TransCanada Power Marketing LTD., 2010) (TransCanada Power Marketing LTD. v. Ian A. Bowles et. al., 2010). The New York State Energy Research and Development Authority also faced similar challenge regarding its geographic eligibility for the agency's long-term RPS procurement, which is limited to resources located within New York state or off-shore resources that are directly interconnected to the New York Grid. In an order issued in May 2013, the New York Public Service Commission asserted that the geographic eligibility limit does not violate the Interstate Commerce Clause due to the agency's role as a market participant (there is a "market participant exception" based on principles created by case law). (New York Public Service Commission, 2013)

Solar carve-out policies create predictable demands for solar PV generation and, if paired with long-term contract or tariff policies or other revenue-stabilizing tactics, can provide a degree of long-term revenue expectations sufficient to attract investment. However, compared to implementation approaches which provide stable revenue – standard offers and competitive long-term contracts – the revenue volatility in SREC markets is less attractive to investors. This leads to SREC markets having a higher cost of capital (New York State Energy Research and Development Authority, 2012) and often a difficultly in attracting debt financing, particularly early on in a policy's life. But our own market analysis reveals that experience in Massachusetts has shown that as market participants became more familiar with a policy and gain experience with its operation, many lenders have grown sufficiently comfortable with SREC risk to lend in this market environment. (Sustainable Energy Advantage, LLC; Meister Consultants Group, Inc.; LaCapra Associates; The Cadmus Group, Inc., 2013)

Further, compared to standard offer policies, RPS and solar set-asides encourage competition that, all else equal, favor least cost projects. On the other hand, fixed demand target schedules prevent set-asides programs from reacting to market conditions without legislative or regulatory changes. Constant policy changes can create uncertainty and affect generator revenues. (New York State Energy Research and Development Authority, 2012)

Net Metering

Net Metering Crediting Mechanism

Net metering is a well-understood and widely-adopted solar implementation approach that has been an important driver for customer-sited PV generation. Net metering rules require T&D utilities to credit their self-generating customers for the excess electricity produced from their PV systems. They are designed to provide solar system owners with a predictable revenue stream at a higher level than potentially available through sales of energy at wholesale, facilitate on-site solar generation by allowing a monetization of the value of PV production out of reach for unsophisticated retail electricity customers, and allow customers to realize utility bill savings by offsetting their own loads by displacing their own use independent of temporal production and usage. Typically, the excess generation over the course of a month is credited the net metering customer's utility bill in the following month as a reduction in energy usage. The credits can be carried over for a specific period of time, after which any unused credits will be eliminated. The costs of the program (i.e. lost utility revenues) are then passed through to ratepayers as net metering recovery charges on utility bills. For this reason, net metering is seen by utilities as a cross-subsidy between participants and non-participating customers. While historically the degree of cross-subsidy has been trivial, with the recent growth in solar penetration, electric utilities nationwide have recently turned to characterizing continued unmitigated net metering as an uncompensated use of their systems and an existential threat to ability to be paid for the services their systems render. (Kennerly, Wright, Laurent, Rickerson, & Proudlove, 2014)

Net metering rules normally include individual system size limits, sometimes differentiated by customers sectors (e.g. public versus private). Statutory changes over the past several years have increased typical system size caps to the 1 to 2 MW range in many states. Further, net metering programs are often capped at a certain specified percentage of utilities' loads. Massachusetts has separate program caps for the public and private sectors. In Massachusetts, small renewable energy systems (less than 10 kW on a single-phase circuit or less than 25 kW on a three-phase circuit) are not subject to the aggregated caps altogether.

Virtual Net Metering Crediting Mechanism

Several states have expanded their net metering rules to provide customers with more flexibility. For example, virtual net metering rules allow a customer or multiple customers to aggregate their usage across multiple meter and net meter multiple units at separate facilities or on different properties. As a result, customers can offset electricity consumed from one site with electricity generation produced from a system at a remote site. (DSIRE Solar Policy Guide: A Resource for State Policymakers, 2012) The net metering credits can be allocated to the customer(s) in a pre-determined arrangement. In most states, virtual net metering is limited to municipalities, state and agriculture customers only. Virtual net metering also enables government entities to access solar tax incentives through a third-party ownership model. (Barnes, 2013) However, some states (such as Massachusetts) have instituted relatively liberal policies. The Massachusetts legislature established several means to virtually net meter, through mechanisms referred to as neighborhood, municipal and agricultural net metering. (Chapter 169 of the Acts of 2008, 2008) Under neighborhood net metering, for instance, a group of 10 or more residential customers within the same distribution company may own or contract with a net metering facility within their utility load zone and each get credit for the output. Depending on the net metering class, virtual net metering moderately to dramatically enhance the economics of distributed PV installations by crediting most avoided retail rate components regardless of the size of the host load. This has led to multi-MW installations at locations without prior load (where the PV facilities own usage, such a security lighting, can qualify as the retail customer) availing themselves of net metering through the sale of net metering credits to municipalities and other off-site parties at a discount. This has become a major pathway to monetizing compensation for what would otherwise be deemed wholesale electricity at a value reflecting the allowed components of retail rates which may be credited under three different classes of net metering facilities. It opened up the market to substantial growth under the state's SREC-I carve-out which has subsequently been pared back somewhat under the more restrictive SREC-II carve-out. And at present, it is also stimulating considerable activity in a specialized subsector, community-shared solar.

Community-Shared Solar[72]

An increasingly prevalent net metering arrangement is community shares solar (CSS), a form of community net metering which enables multiple customers (usually capped at a fixed number) to share ownership interest in a single remote net metered facility and allocate the credits based on pre-

[72] For more information, see IREC's Model Rules for Shared Renewable Energy Programs: http://www.irecusa.org/wp-content/uploads/2013/06/IREC-Model-Rules-for-Shared-Renewable-Energy-Programs-2013.pdf.

determined arrangements, such as proportional to ownership interest. CSS provides a platform for electricity customers in a community or condominium to jointly purchase a shared solar project. It provides solar access to customers who otherwise cannot host an onsite system, for instance because of building orientation, shading, building condition, multi-tenant buildings, etc. Further, by using a pooling approach, it supports participation in small increments, making solar more affordable, thus enabling low-income customers to participate. (Interstate Renewable Energy Council; Vote Solar, 2014). This community-shared ownership model has gained nation-wide popularity in recent years. Massachusetts, Rhode Island and Vermont have all authorized community net metering through legislation. New York is working on developing community net metering rules in 2014 and 2015 under the state's Reforming the Energy Vision initiative. (Durkay, 2014) Many advocates cite CSS as the democratization of solar, opening up participation of solar to all. Of course, CSS, which relies on net metering, triggers the same issues with cross-subsidization and use of utility facilities without paying for them as other virtual net metering installations.

Given the rapid growth in the grid-tied solar market, several states have approached their net metering caps. Increasing the net metering program caps typically require legislative authorization. Vermont[73], Massachusetts[74] and New York[75] , for example, all raised their program caps in 2014. However, as popularity for solar PV continues to grow and controversy regarding the cost impact of net metering deepens, many states have started exploring other implementation options. Vermont, Massachusetts and New York all recently initiated investigations to explore and develop longer-term and more sustainable alternatives to net metering.

State policy makers should also be aware that expanding access to net metering would accelerate the depletion of aggregated net metering capacity available in states with net metering caps. Utilities typically argue that high rates of rapid adoption could lead to greater risk of cost-shifting to non-participants.

[73] Act 99, enacted in 2014, increases the cumulative output capacity of net metering systems from 4% to 15% of the distribution company's peak demand during 1996 or the peak demand during the most recent full calendar year, whichever is greater. Further, it directs the Public Service Department to conduct a study on net metering in Vermont and identify best practices for net metering in other states. (An Act Relating to Self-Generation and Net Metering, 2014) (30 V.S.A. §219a Self-Generation and Net Metering, n.d.)

[74] The Massachusetts legislature enacted Chapter 251 in 2014 to increase the public and private net metering caps to 5% and 4% of peak loads (previously 3% for both sectors) respectively and ordered the creation of a Net Metering Task Force to evaluate the long-term viability of net metering in Massachusetts. (An Act Relative to Credit for Thermal Energy Generated with Renewable Fuels, 2014)

[75] The New York Public Service Commissioner, on December 15, 2014 issued a ruling in response to various solar stakeholders. The ruling increased the aggregate net metering cap for each utility to 6% of peak load. The ruling also directs its staff, in consultation with the New York State Energy Research and Development Authority, to identify a methodology to measure and properly value distributed generation resources. (New York Public Service Commission, 2014)

Finance Enabling Policies

Financing enabling policies enhance the accessibility of financing, lower financing transactions costs, open up access to lower-cost forms of financing, and otherwise lower the entry barrier to solar investment and enable a broader range of players to participate in the solar market.

Solar Loan Programs (Non-Subsidized or Indirectly Subsidized)

Solar loan programs can be implemented with different models and funding options. Non-subsidized or indirectly subsidized loan programs are supported by private sector financing options or utilities. PACE financing and on-bill financing, discussed further below, are specialized approached to non-subsidized loan programs. Generally, solar loans are targeted to residential customers who cannot afford the high upfront cost of solar and are not sophisticated enough to obtain private loans. These programs are also developed by states to create scale to the residential lending market, standardize transactions thus lowering transaction costs, familiarize and attract lenders to the market. Solar loans do not reduce the overall cost of solar PV installation, but lower the up-front cost by spreading the total cost over time, and in some instances may also lower interest costs. Connecticut's Green Bank recently established innovative programs, and in 2015 Massachusetts is rolling out a program driven by the Department of Energy Resources which will feature loan-loss reserves, interest rate buy-downs and advantageous terms for low-income homeowners. (Massachusetts Department of Energy Resources, 2015)

Recently, emerging solar loan products that incorporate innovative financing options or repayment models have provided system owners with more low-cost financing options for solar PV:

- In New Jersey, PSE&G's Solar Loan Program allows residential and commercial customers to repay their loan obligations with cash payment of SRECs. The program includes a floor price guarantee for SRECs generated by the systems. This design allows system owners to offset their loan obligations with SRECs generated by their systems, reducing actual out-of-pocket costs for the PV. (PSE&G, n.d.)
- The Connecticut Green Bank is working with multiple financing groups to create a crowd-sourced loan product for solar installations. The loan program uses projected energy savings as the basis for the loans and provides key protections, such as guarantees on system performance, for homeowners. The program will aggregate funding for the loans from American investment partners and repay investors through an online marketplace. (Clean Energy Finance and Investment Authority, 2014)

PACE Financing

Property-Accessed Clean Energy (PACE) financing is an implementation approach that allows municipalities to offer long-term, low-interest loans on customer-sited installations that are tied to the property where the project is hosted instead of the system owner. While used more broadly on energy efficiency investments, PACE programs are increasingly being targeted at solar PV installations Similar to most finance-enabling approaches, PACE financing lowers the entry barrier to solar PV installation by spreading the project cost over a long period of time. Tying the loan obligations to the property instead of the system owner's credit standing also reduce the loan's risk profile. (New York State Energy Research and Development Authority, 2012). Under PACE financing, repayment obligations are made through a special assessment on property taxes. Unlike typical loan products, PACE financing allows loan obligations to be transferred along with the sales of the property. This design feature makes PACE financing very attractive to homeowners and business customers, and removes a barrier to solar adoption for those unsure whether they will be in their home long enough to recoup the investment. States that have adopted PACE programs often distinguish between commercial (C-PACE) and residential programs. C-PACE is more widespread than residential programs. The residential PACE program had significant momentum several years ago, but quickly ground to a halt after the Federal Housing Finance Agency issued a decision that made it impossible to implement a residential PACE program that assigns a senior lien to PACE financing. Several states have bypassed this rule by passing legislation that removes the senior lien provision in PACE programs and instead assigns PACE financing a subordinate lien. (DSIRE Solar Policy Guide: A Resource for State Policymakers, 2012).

On-Bill Financing

On-bill financing is a long-term, low-interest loan servicing tool that is typically used for financing energy efficiency retrofits. This model allows PV system owners to repay their loan obligations through their utility bills. Similar to PACE financing, on-bill financing allows the loans to be tied to the property instead of the system owner and can be transferred with the sales of the property. So, like PACE financing, on-bill financing can removes a barrier to solar adoption for those unsure whether they will be in their home long enough to recoup the investment. New York currently provides an on-bill recovery loan option for residential and small business/not-for profit solar installers. Under the state program, the monthly repayments cannot exceed the estimated cost offset by on-site generation from the solar project, therefore ensuring that project cost can be mostly recovered from energy savings. (Financing Options for NY-Sun Incentive Program, n.d.)

Green Banks and Their Programs

A Green Bank is a state-chartered institution that offers a suite of programs and financing products designed to provide affordable access to clean energy development to a wide range of audience. As an alternative to incentive approaches, states can establish Green Banks that leverage and recycle public funding to stimulate the growth of private financing markets for solar and other clean energy investments, while ensuring efficient use of public funds. (Brookings Metropolitan Policy Program; Clean Energy Finance and Investment Authority; Coalition for Green Capital, 2014) Green Banks can be established using multiple models (Coalition for Green Capital, n.d.):

- **Quasi-public corporation –** Leverages state public funds with private capital to create an institution that offers loans and financing products for solar and clean energy investment (e.g. Connecticut Green Bank)

- **Housing Green Bank in existing state agencies –** States can choose to offer financing tools utilizing the Green Bank model within state agencies (e.g. New York Green Bank housed within in NYSERDA)

Connecticut established the first state-based Green Bank program in the U.S. in 2011. It is the only operating Green Bank among the states considered here. The Connecticut Green Bank (originally known as Clean Energy Finance and Investment Authority) repurposed the state's public good funds and Regional Greenhouse Gas Initiative proceeds as seed capital to leverage private capital for a suite of products aimed at removing the upfront cost or minimizing the investment risk of solar PV. (Brookings Metropolitan Policy Program; Clean Energy Finance and Investment Authority; Coalition for Green Capital, 2014) These products include Commercial-PACE, solar insurance, loan loss reserves, and solar leases.

The nascent New York Green Bank is housed within and managed by the New York State Energy Research and Development Authority (NYSERDA), but has yet to launch its first formal programs, but in late 2014 announced its first series of investment commitments.[76] Similar to the Connecticut Green Bank, the New York Green Bank will be built on public funds from the state and play a major role in the state's Reforming the Energy Vision initiative.[77] The Bank will partner with private entities to fill gaps in the clean energy financing market and remove financing barriers to clean energy development. Specifically, it will focus on projects that are economically viable but not currently financeable.

By leveraging private investments, Green Banks replace or augment ratepayer/taxpayer-subsidized incentives, and hence, lower the public cost of solar development. Further, by creating long-term, low-cost financing support, Green Bank reduces system owners' reliance on expiring tax credits, public funds and subsidies. They can reduce the size of subsidy required to stimulate a PV installation and accelerate the timetable to the day when direct subsidies are no longer needed. The relatively low budgetary demand makes Green Bank a compelling implementation approach, especially during state budget shortages. (Berlin, Hundt, Muro, & Saha, 2012) As a result, Green Banks are less vulnerable to budget raids and political changes, adding stability and predictability to the solar investment market.

Utility Ownership

In decoupled electricity markets, T&D utilities are typically not permitted to have ownership interest in generation assets. Several states, including Connecticut, Massachusetts, Vermont and New Jersey, have authorized utility-owned solar generation subject to very restrictive conditions under state regulators' approval. RECs generated from the utility-owned systems can be used toward satisfying RPS (or solar set-aside) obligations. The utilities can choose to use the electricity generated to serve its retail loads or

[76] See: http://greenbank.ny.gov/initial-transactions

[77] The New York Green Bank was created using uncommitted proceeds from the state's Energy Efficiency Portfolio Standard and System Benefits Charge programs. (New York Public Service Commission, 2013)

resell it to the spot market. The net difference between cost and market value associated with the utility-owned generation is passed through to distribution ratepayers as recovery charges on utility bills.

Utility ownership adds another layer to market diversification strategies. Initially, utility ownership could access a lower cost of capital than available to independent power producers; with recent innovations and advancements in solar PV financing, this may no longer be the case. This ownership model can also lower the cost of solar PV generation by eliminating the costs involved in typical utility-generator transactions. Additionally, utility-ownership programs allow utilities to experiment with specific project types or advanced technologies and explore additional values of solar to the grid system and ratepayers. National Grid, for example, is developing 16 MW of solar projects in areas with high load density in Massachusetts to study the impact of solar generation equipped with advanced meters on system reliability, alternative orientations to maximize peak values, and quantify the potential system benefits from strategically-located PV. (National Grid, 2014)

Solar Lease and/or Third-Party Ownership Enabling Policies or Eligibility in Other Policies

Third-party ownership has emerged over the past few years as a solar development model common for residential and small business customers, as well as local governments, who often lack the upfront capital for the system equipment or do not want to install or maintain solar systems (due to lack of sophistication or risk aversion). The advent of this model has been highly correlated with significant expansion of state solar PV markets, unlocking participation by substantial segments of the market. (Solar Energy Industries Association, 2014) Sometimes municipalities and non-profit entities also utilize third-party ownership to indirectly access the benefits of tax incentives which they are unable to monetize directly. (DSIRE Solar Policy Guide: A Resource for State Policymakers, 2012).

Third-party ownership typically involves a private developer installing and owning a PV system hosted by a residential or commercial property owner, then selling the power generated from the system to the property owner at a pre-negotiated price over a period of term through power purchase agreement. Another model is a solar lease, which allows customers to lease PV panels, usually at a fixed cost over a long term from a supplier.

While third-party ownership is more of a financing approach than a policy itself, net metering or solar policies can either enable or preclude this model by virtue of eligibility restrictions. Policies crafted to allow, welcome or target third-party ownership remove barriers and create opportunities for these models. In order to enable third-party ownership, states need to create rules that prevent the seller end of a third-party power purchase agreement from being regulated as an electric utility or competitive supplier, a requirement which has proven too burdensome to make market entry attractive. States may also explicitly authorize third-party ownership models in their net metering regulations. New Jersey, for example, states a customer-generator is not required to own the net-metered solar PV system, provided the system is hosted on its property. (Kollins, Speer, & Cory, 2010) To increase market participation through third-party ownership, states can also make third-party owned systems eligible for other solar programs and incentives. Connecticut allows third-party owned behind-the-meter generation to participate in the ZREC solicitation (Connecticut Light & Power Company, United Illuminating Company, 2014), and targets a PBI at 3rd-party owners under its Residential Solar Incentive program.[78]

[78] See: http://www.energizect.com/residents/programs/residential-solar-investment-program.

Rules, Regulations and Rate Design

Rules & regulations at all levels of government ensure legal access to the solar market and provide technical support to solar PV deployment. (Doris, 2012) Some rules and regulations are designed to remove institutional barriers. Building codes and standards prepare infrastructures for solar installation and familiarize installers and inspectors with the technology and its requirements for safe installation. Other rules and regulations may grant legal authorization to alternative solar installation models, such as Third-Party Ownership, that can ease access to the solar market. Some rules are created to regulate the economics of solar generation. For example, states can implement rules that compensate T&D utilities for the cost of integrating distributed solar into the grid systems from customers (which we discuss under the category of Rate Design), while providing a means of compensation for solar generation (which we discuss under the category of Indirect Financial Support). Another example is to internalize the public benefits of solar generation through the tax code. Finally, Grid Modernization rules and regulations are implemented to enforce investment in distributed-generation-friendly grid architecture.

Removing Institutional Barriers

Interconnection Standards

States are responsible for regulating distributed interconnection (whereas transmission interconnection is typically overseen by regional system operators). To standardize and add transparency to interconnection procedures, the ten states reviewed here have each implemented interconnection standards. Interconnection standards set forth the legal, technical and procedural requirements for customers who wish to connect the PV systems to the grid (DSIRE Solar Policy Guide: A Resource for State Policymakers, 2012). Interconnection standards are typically applied to distributed solar systems of all sizes. Most states have more relaxed interconnection rules and screening procedures for small, simple systems. The procedures become more stringent as the system size increases, and/or when multiple projects connect to a single feeder or the PV generation on a circuit approaches the scale of load on the circuit. Further, interconnection standards may include multiple tracks of interconnection procedures (e.g. simplified, expedited, etc.) that are designed for project of different system sizes that may require different levels of review.

Well-designed interconnection standards can increase investment appetite by lowering development uncertainty and reducing time, and hence, development costs, for solar PV. An interconnection regime with predictable costs and timelines facilities a robust investment environment, while unpredictable costs can result in much wasted development effort, and unpredictable interconnection timelines can result in completed projects sitting idle awaiting interconnection, which can materially undermine expected financial performance of generators. The Interstate Renewable Energy Council (IREC) provides model guidelines for interconnection policies.[79]

Solar Access Laws

Solar access laws, such as solar easements or solar rights, protect solar system owners by securing their continued access to sunlight or remove zoning or building code barriers for solar development. These options can be implemented at the state and local level. (DSIRE Solar Policy Guide: A Resource for State Policymakers, 2012)

Business Formation/Financing Laws

State legislators can enact policies to authorize certain types of business models or market structures that aim to lower the entry barrier and expand access to the solar market. Crowd-funding, cooperatives and community solar are all innovative examples that have gained popularity nationwide in recent years. The objective would be to create paths to enable such business structures while balancing consumer (or investor) protections with onerous securities regulation.

Permitting Standardization, Simplification & Streamlining and Other "Soft-Cost Reduction" Strategies

Cumbersome and costly permitting and inspecting procedures could increase project cost and development time, hindering market growth. A recent report by the National Renewable Energy Laboratory and Rocky Mountain Institute identified four steps to reducing permitting and inspection related costs: (Ardani, et al., 2013) [80]

- Standardization of requirements across local jurisdictions;
- Transparency of requirements (e.g. creating publicly accessible database on requirements and provide real-time data on permitting/inspection status);
- Online permit application submittal; and
- Lowering market-wide average permitting fees.

It is estimated that permitting and inspections account for 6% of solar PV soft-costs. The remainder includes customer acquisition costs, installation labor costs and financing. States can implement a variety of soft-cost reduction strategies to reduce the capital cost of solar installations. In order to reduce customer acquisition costs, states can launch consumer awareness campaigns and support standardization of PV system designs. States can also implement building codes and standards, such as "solar-ready" standards and "plug-and-play" configurations to bring down installation labor costs. (Ardani, et al., 2013)

[79] International Renewable Energy Council. http://www.irecusa.org/regulatory-reform/interconnection/
[80] The report was developed as part of the U.S. Department of Energy's SunShot Initiative to identify soft-cost-reduction pathways in order to achieve the Department's PV price targets. For more information on the SunShot Initiative, see: http://energy.gov/eere/sunshot/sunshot-initiative.

Building Codes

Solar-Ready Building Standards or Zero Energy Capable Home Standards

States can implement building standards to ensure future solar installations or “zero-energy” upgrades would not be limited by the design or layout of a new infrastructure. Such standards may regulate orientation, shading, and other siting- and construction-related criteria, or may support acceptance of ‘plug-and play’ solar PV system configurations. (U.S. Department of Energy, 2012) California has recently started experimenting with solar-ready building codes for residences in special “Solar Zones.” (California Energy Commission, 2014) There are currently no known examples in the Northeast.

Tax

Property Tax Exemption or Special Rate

Property taxation of distributed solar installations creates a dilemma for communities. Property tax revenue is entirely incremental, particularly for rooftop or brownfield installations, yet too high a rate will simply chase developers into other locations. Property tax rates and their application or appraisal can vary by location, municipality or appraiser.[81] Because property tax often constitutes a significant fraction of operating expenses, the difficulty in predicting property tax obligations can be problematic for developers or owners under some implementation regimes. This is particularly true if it is difficult to predict with precision how large an impact property tax obligations may have until after substantial investment in an installation has occurred, or a bid has been offered under an incentive solicitation.

Property tax relief policies are designed to remove or mitigate disincentives for solar development by protecting residential and business property owners installing solar systems from higher property taxes.[82] Property tax exemptions exempt the added value of solar development from being included in the assessment process for property tax purposes over an administratively-set period of time. Typically, the exemption can only be applied to generator-owned systems that are hosted onsite. In some states, the exemption is tied to equipment dedicated to the production of energy for use in or at the facility.[83] In some cases, the equipment must be owned by the building owner, creating potential problems for third-party leases, leased buildings or condominiums. However, Massachusetts recently found that certain virtually net-metered systems hosted on properties owned by the generator should also be

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[81] Real estate appraisers are gaining familiarity with rooftop solar, but training and education in that sector would be valuable in improving community understanding of solar generation.

[82] One unintended side effect of property tax exemptions is that appraisers do not need to improve their solar system valuation skills.

[83] Such conditions can create complications for FIT other sale arrangement, if the property must be properly depreciated and income must be recognized.

eligible to receive property tax exemptions.[84] Special rates policies require properties hosting solar systems to be assessed at a discounted rate.

An alternative to property tax exemption policies is Payment-In-Lieu-Of-Tax (PILOT), which allows a system owner to make payments to the local government at a pre-negotiated rate over a period of time in lieu of property taxes. This approach is usually applied to larger, ground-mounted solar projects. While property taxes are usually collected at the local level, states may permit or require their municipal governments to implement property tax exemption or special rate policies for solar PV. Other states may allow communities to voluntarily offer such exemptions. This is the approach used by Rhode Island.

Tax exemption policies are very common, as they are generally much more politically viable than direct financial incentives as they are easy to administer and do not require an explicit funding mechanism. (DSIRE Solar Policy Guide: A Resource for State Policymakers, 2012). They also create beneficial local economic development multipliers and increase the overall value of the housing and building stock by encouraging local investment. (See recent Wiser study, showing that rooftop solar, in general, adds $4 per watt installed to home value.) Further, they are considered to be non-impactful as they do not increase the cost of solar installation for systems owners or reduce government tax revenues. Additionally, they can be implemented with a wide range of incentives, regulations and rules.

Sales Tax Exemption

Similar to property tax relief policies, sales tax exemptions lower the barrier to participate in the solar market. By exempting system owners from pay sales taxes for the PV system equipment, sales tax exemptions lower the cost of solar PV installation. Sales tax exemptions are usually offered to all system sizes and customer classes (e.g. Connecticut, Rhode Island, Vermont, New York, Maryland, and New Jersey). However, some states limit exemptions to certain customer sectors. Massachusetts, for example, only offers solar sales exemptions to residential customers. New Hampshire and Delaware do not have sales tax exemptions as they do not have a sales tax.

Property Tax/Payment-In-Lieu-Of-Tax (PILOT) Standardization or Simplification

Property tax application and assessment can vary dramatically from community to community, and often the amount of property tax to be due is difficult to predict, making it challenging for developers to project revenue requirements for viability before bidding for contracts or making investments. By standardizing and simplifying property tax and PILOT rules for solar PV development, states and municipalities can reduce the time installers spent examining property tax rules for each local jurisdiction, and remove an unnecessary uncertainty and risk. This approach can avoid local tax disputes

[84] The Massachusetts Appellate December 4, 2014 decision ruled narrowly that virtually net-metered systems sited on properties owned by the net metering customer should be permitted to receive property tax exemption for the solar facilities. However, the broader application of this decision, to both Community Shared Solar and transactions where an investor owns a system, and sellers of power or net-metering credits to a third-party property, is unclear. (Forrestall Enterprises Inc. v. Board of Assessors of the Town of Westborough, 2014)

that can disincentives solar development and create greater certainty for solar system owners. Further, it helps reduce the soft cost of solar PV, lower entry barrier to the market, and facilitate solar adoption.

Grid Modernization

Policies Enabling Micro-grids, Smart-Grid and Other DG-Friendly Grid Architecture

Distributed generation can play a significant role in enhancing grid resiliency when incorporated in micro-grid and other smart-grid systems. Distributed-generation friendly technologies and grid architecture can ease the interconnection of distributed generation and advance the implementation of such systems. States can adopt policies that promote installation of such technologies or require more comprehensive grid modernization planning. Several states studied here have adopted grid modernization policies to various degrees:

- **Massachusetts –** The Massachusetts Department of Public Utilities initiated a regulatory proceeding directing the state's distribution utilities to conduct comprehensive grid modernization planning with the intent to integrate distributed resources, reduce the effects of outages, and optimize demand, which includes reducing system and customer costs. Utilities are required to provide ten-year grid modernization plans and business cases outlining how the companies plan to implement measure grid modernization effort. (Massachusetts Department of Public Utilities, 2014)

- **Connecticut –** The Connecticut legislature implemented a micro-grid grant and loan pilot program to promote local distributed generation for critical facilities. The program operates under a competitive solicitation process. In the past two solicitations, the state awarded grants to a mix of solar PV, fuel cell, cogeneration and combined heat and power projects. (Connecticut Department of Energy and Environmental Protection, n.d.)

- **Maryland –** Maryland has been working with its distribution utilities to roll out a smart-grid program. The first phase of the program, implemented in 2011, was the installation of smart meters, which among a series of benefits, would enhance solar PV compatibility with the grid system and provide more effective communications between solar customers and utilities, which may result in solar generator friendly rate designs or other incentives. (Maryland Energy Administration, n.d.)

Rate Design

It is the job of utilities regulators to apply a series of traditional ratemaking principles to balance sometimes conflicting objectives. Among these, cost-based rate design or rate structure for the purchase of electricity supply and transmission and distribution services will serve to provide customers a correct price signal for the installation and operation of solar generation facilities.[85] Rate structures which vary by time to reflect the temporal variation in cost causation are one such tool receiving significant attention industry-wide.[86] For the most-part, such cost-based rate designs involves time-varying rates or time-of-use (TOU) rates which charge and compensate customers for consumption and generation at different energy prices during on-peak and off-peak hours. If solar production is high or consumption is reduced during high-value, on-peak hours, TOU rates can improve the economics of solar generation (although solar is limited in its ability to respond to price signals, coincidence of production and high-prices hours would properly increase compensation to solar customers relative to average rates). A more technically complex related option is "dynamic pricing," which adjusts energy prices based on changing market demand and supply conditions. (Linvill, Shenot, & Lazar, 2013). Dynamic pricing that adjusts electricity supply prices by hour reflect daily and seasonal differences in electricity supply costs. TOU rates can reflect, to the extent they exist, daily and seasonal differences in electricity delivery costs.

Fixed or customer charges in electricity bills tend to reduce the economic payback value of customer solar installations. However, it should be recognized that a certain portion of a utility's costs are fixed and are not lowered by reduced consumptions. Therefore, some type of fixed charge, such as a customer charge or minimum bill, is often part of an appropriate rate design process. The "minimum bill" model allows customers to reduce their bill with efficiency or self-generation, but only to a certain minimum level.

Such a minimum bill, influenced by a cost of service study, seeks to address the traditional ratemaking principles of utility cost recovery for use of their facilities and setting utility rates based on costs, and could, when applied equitably to all customers, be designed to avoid unduly penalizing low-usage customers, energy conservation and distributed generation. Within limits, this approach can mitigate disproportionate impacts on customers with behind the meter distributed generation often raised

Industry Support

Industry support approaches are often paired with incentives, rules & regulations and rate design strategies to accelerate solar deployment. By incentivizing in-state solar investment, many industry support approaches are also designed to simulate local job creation and foster state economic growth.

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[85] Other principles include cost-causation, gradualism, fairness, equity concerns, adequate customer segmentation, and encouragement of efficiency.

[86] There is significant interest in this topic, with advocacy enumerating benefits that such price signals can enable in combating peak system demands and incentivizing efficient use of resources. There is however ongoing debate as to whether residential customers can or will effectively respond in a meaningful fashion to such price signals, and enabling such responses can involve costs (in sophisticated metering and other technology) which some have debated may outweigh the benefits. This debate has so far served as a damper on universal adoption of mandatory time-varying rates. Such factors are mentioned here for completeness but beyond the scope of this study.

Incentives for Companies, Technology Development Funds or Economic Development Funds

To promote local economic development, states can leverage technology development funds, economic developments funds and other funding mechanisms to provide incentives for in-state solar businesses, such as solar equipment suppliers, contractors, etc. These funds can be allocated from the state budget, ACP payments, RGGI proceedings, and public good funds.

Local Content Bonuses or Mandates

Local content bonuses or mandates support investment in local solar industries by supporting the employment of local labor force or use of technologies manufactured in-state. These policies usually exist in other programs as eligibility requirements, evaluation criteria, or incentive adders. For example, the Connecticut legislature allows the state Public Utilities Regulatory Authority to give preference to contracts that use technologies manufactured, researched or developed in the state.[87] The Massachusetts Commonwealth Solar Rebate II program provides an incentive adder to solar projects that use modules, inverters or other significant electricity production components manufactured by a company with a significant Massachusetts presence.[88] Under some circumstances such incentives may be subject to challenge under the Interstate Commerce Clause of the US Constitution, or under trade agreements, so care should be taken before pursuing such avenues.

Customer Acquisition Cost Reduction (e.g. Solarize Initiative)

A 2010 survey estimated that the average customer acquisition costs for residential PV systems was $0.67/W. (Ardani, et al., 2013) States can leverage the economy of scale to increase solar participation at a lower cost. "Solarize" is a cost reduction strategy mainly targeted to residential and small business customers. Through this community-oriented approach residents and small business owners from participating communities will receive pre-negotiated solar installation discounts through bulk purchases resulting from state-run solicitations for vendors. These discounts are often structured as tiered-pricing, where the pricing lowers with increased participation. (Condee, 2014). Table 42 is an example of Solarize Massachusetts' tiered pricing.

Table 43 – Solarize Massachusetts Example Tiered Pricing

	Tier 1	**Tier 2**	**Tier 3**	**Tier 4**
Contracted Capacity	1 – 100kW	>100 – 200kW	>200 – 300kW	>300kW
Installed Price ($/W)	5.08	5.03	4.98	4.93

[87] http://www.cga.ct.gov/current/pub/chap_283.htm#sec_16-244r
[88] http://images.masscec.com/uploads/programdocs/CSII_Program%20Manual_V20_Final.pdf

3rd Party Pre-Paid ($/W)	2.88	2.86	2.81	2.78
Leased Price ($/kWh)	0.108	0.104	0.10	0.096

States will also provide small subsides for coordinated community-based education, marketing, and outreach efforts. Massachusetts and Connecticut are two early adopters of this approach. Both Rhode Island [89]and New York[90] have announced their own versions of Solarize incentives in late 2014.

Outreach, Education, Public Information or Voluntary Market Encouragement

Lack of costumer awareness can impede solar adoption, especially in the residential and small C&I sector. States can educate residents and businesses on how the voluntary and compliance solar markets work, as well as inform customers of solar funding and financing options through outreach and education programs. Example initiatives include consumer workshops and development of a central information web portal that provides a one-stop-shop to information on solar technologies, funding and financing opportunities, qualified solar installers and vendors. States can also consider more innovative models capitalizing emerging resources for public engagement and social media.

Public Sector Leadership and Demonstration (e.g. Solar on Schools)

States can implement lead-by-example strategies to increase awareness and create education and outreach opportunities for solar PV development. Strong local and statewide solar programs can also add important sales and business volume to the sector, facilitating more full-time employment and reducing “boom and bust” cycles in markets. Typical lead-by-example strategies include installing demonstration projects on public properties and establishing statewide solar generation goals.

Example of lead-by-example initiatives:

- **Massachusetts –** In 2014, Massachusetts provided capacity-based incentives to state agencies and state universities for solar PV canopy projects through its Leading by Example initiative, which involves a range of clean energy targets for state-owned facilities regarding renewable energy, greenhouse gas emissions and other energy and environmental goals. The state also awarded multiple grants to municipalities for an inventory of clean energy resiliency projects,

[89] In summer of 2014, the Rhode Island Office of Energy Resources and Rhode Island Commerce Corporation announced that they will jointly administer Rhode Island’s version of the “Solarize” program. Phase I of the program will be launched in fall 2014 in North Smithfield. Phase II of the program, which will begin in early 2015, will focus on the Towns of Little Compton and Tiverton. OER and Commerce RI will consider how the program will expand after the first two phases are complete, sometime in summer 2015.

[90] New York State initiated Community Solar NY under the NY-Sun initiative to make solar more easily accessible and affordable through community-driven strategies. The state will be launching Solarize campaigns in participating communities in spring 2015.

among which include several solar PV systems for emergency generation during outage. (Massachsuetts Executive Office of Energy and Environmental Affairs, 2014)

- **Rhode Island –** Rhode Island offers a competitive grant using its RGGI auction proceeds for renewable energy projects at K-12 schools throughout the state. The program requires applications to contain and education element as part of the project. (Rhode Island Office of Energy Resources, 2014)

Creation of Public Good Funds to Support Solar Programs and Policies

States can create public good funds to provide long-term funding for solar incentive programs. Public good funds are typically collected from ratepayers as a surcharge on electricity customers' utility bills. The surcharge could be a fixed monthly rate (e.g. $/month) or based on electricity consumptions (e.g. $/kWh). Public good funds can also be established through utility merger settlement proceedings. The Pennsylvania Sustainably Energy Funds are supported by utilities in lump-sum payments. Merger settlements between Allegheny Power and First Energy, PECO and Unicom, and GPU Energy and First Energy have resulted in additional payments to the Funds. {Need to find original dockets} (DSIRE Solar Policy Guide: A Resource for State Policymakers, 2012)

Public good funds, in conjunction with ACP and RGGI proceeds, can be allocated to a variety of solar programs and other clean energy initiatives such as those detailed in this report. Direct up-front incentives like rebates and grants are often supported by public good funds. It should be noted that in years of budget shortage, public good funds have been raided in many states to fill state budget gaps, reducing available funding for renewable initiatives. Some states have hired independent administrators to manage public good funds and prevent them from being used for general budgetary purposes. However, this is not a fool-proof method, as evidenced by the Connecticut Clean Energy Fund raid in 2013.

Installer and Inspector Training and Certification

States may create training and certification procedures for solar installers and contractors to help build a qualified local workforce which might otherwise serve as a constraint to growth. Alternatively, states may adopt installer requirements or pre-approval procedures in their incentive programs to encourage participation while ensuring safe practices and system performance. For example, new installers participating in the Massachusetts Residential Solar Loan Program are subject to state inspection of their first two projects. If the inspection is successful, the installer will be expedited moving forward. (Massachusetts Department of Energy Resources, 2015).

Some states implement installer licensing requirements or training and certification programs to protect customers from unsafe practices, ensure system performance, and maintain industry reputation. (DSIRE Solar Policy Guide: A Resource for State Policymakers, 2012). For example, Connecticut has a solar contractor licensing program administered by the state's Department of Consumer Protection. Contractors must obtain a license in order to perform solar energy work within the state. (Regulations of State Agencies Title 20, 2008).

In addition to providing proper training to solar installers, states may wish to educate building inspectors on the structure review and approval for solar PV systems. The Massachusetts Department of Energy Resources, for example, has created multiple guidelines on the topic and hold regular training sessions to help solar installers and inspectors understand the permitting and review process. (Massachusetts Department of Energy Resources, 2014).

Implementation Option Evaluation and Analysis

Introduction

Maine's Solar Implementation Status

Compared to neighboring states, Maine has a relatively small solar market. As of the end of 2014, Maine has installed 11.7 MW in nameplate capacity of solar PV. This represents 0.59% of the state's 3-year average peak load (between 2011 and 2013) of 1990 MW. As compiled by ISO-New England's Distributed Generation Forecast Working Group[91] (ISO-New England Distributed Generation Forecast Working Group, 2014), this penetration level at year-end 2014 is compared to:

- 120 MW (1.7%) in Connecticut[92];
- 530.1 MW (4.1%) in Massachusetts[93];
- 10.7 MW (0.4%) in New Hampshire[94];
- 18.2 MW (0.9%) in Rhode Island[95]; and
- 56.2 MW (5.6%) in Vermont[96].

Connecticut, Massachusetts, Rhode Island and Vermont have all established aggressive policies, programs and other implementation options to grow these figures several fold by a factor of two to six times over the next five years. In addition, New Hampshire has implemented options (grants and rebates under its Renewable Energy Fund, expanded virtual net metering, etc.) to grow these figures materially (New Hampshire Public Utilities Commission Sustainable Energy Division, 2014).

Maine's relatively lower solar PV penetration to date correlates to a degree with a more limited set of implementation options in place to date than these other states, as discussed in Section 0.

Evaluation and Analysis Approach

In this section, we attempt to identify a suite of implementation strategies that might be considered appropriate within Maine's context. The authors first identified a list of priorities and common objectives appropriate for Maine's consideration. Next, based on the literature review on solar PV implementation, the authors discussed various findings common to experiences of other states. Finally,

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[91] More information on each of these state's suite of implementation options can be found in presentations posted at http://www.iso-ne.com/committees/planning/distributed-generation.
[92] http://www.iso-ne.com/static-assets/documents/nwsiss/grid_mkts/key_facts/final_ct_profile_2013_14.pdf
[93] http://www.iso-ne.com/static-assets/documents/nwsiss/grid_mkts/key_facts/final_ma_profile_2013_14.pdf
[94] http://www.iso-ne.com/nwsiss/grid_mkts/key_facts/final_nh_profile_2014.pdf
[95] http://www.iso-ne.com/nwsiss/grid_mkts/key_facts/final_ri_profile_2014.pdf
[96] http://www.iso-ne.com/nwsiss/grid_mkts/key_facts/final_vt_profile_2014.pdf

we identified additional considerations the legislature may wish to account for when examining the various implementation options and approaches.

Evaluation of Implementation Options

To guide the Legislature's analysis effort, the authors identified a set of priorities and common objectives through literature review, research on other states' solar implementation experiences and what we understand of Maine's context. This exercise helped establish a list of illustrative evaluation criteria for assessing the effectiveness of the policy options at meeting different policy priorities. Further, it provided a meaningful framework for comparing and balancing the policy options and objectives in order to identify an appropriate pathway that leads to the most desired outcomes. The legislature should in no way feel bound by such objectives, but may find them a useful starting point.

Table 44 – Policy Priorities and Objectives for Solar PV in Maine

Implementation Priorities	**Implementation Objectives**
Market Growth	• Stimulate a self-sustaining solar market • Supports increased investment in distributed solar • Supports increased deployment in distributed solar
Equity	• Provide fair cost recovery to T&D utilities • Provide just and reasonable compensation to solar customers • Allocates costs equitably among ratepayers
Feasibility	• Establish a policy that is administratively simple, transparent and verifiable • Establish a policy that is viable within the existing political and legal framework
Compatibility with Maine's Energy Market Goals	• Create a market that is compatible with competition in wholesale and retail energy markets in Maine • Diversify Maine's energy portfolio, while ensuring protection of system reliability
Economic	• Facilitate investment and development in in-state solar generation, manufacturing, installation, and R&D industries
Environment	• Advance Maine's environmental goals and improve the state's environment through reducing GHG emissions and other adverse impacts of existing electricity generation

Lessons Learned from Other State's Experiences with Implementing Solar PV

To identify the most effective approach to implementing solar PV, we identified four key themes or lessons learned based on our literature review and research on solar implementation in other states:

- A comprehensive strategy to support solar PV is effective at increasing solar PV penetration.
- Low- or no-cost implementation options - options to enhance distributed solar adoption with minimal financial outlay relative to direct incentive programs - are available, and may be considered either alongside direct incentives, prior to adoption of incentives, or when there is limited appetite for costlier measures.
- Sequencing implementation option in a particular order enhances the cost-effectiveness of solar deployment.
- Adopting synergetic implementation options can advance support for increased solar penetration, while over-stimulation and conflicting implementation objectives may impede or disrupt healthy market growth.

Comprehensive Strategy

One key finding is that a comprehensive approach to support solar PV is effective at increasing solar PV penetration. (Steward, Doris, Krasko, & Hillman, 2014). In all ten states studied here, state policymakers implemented a combination of implementation options simultaneously to maximize the support available for, and reduce barriers to, diverse solar deployment. The Legislature may wish to consider combining various policies, programs rules, regulations rate designs, incentives and industry support strategies to achieve multiple implementation objectives (e.g. develop scale economies, reduce costs, reduce risk and create an attractive investment climate, etc.) and maximize the benefits realized.

Low- and No-Cost Implementation Options

When considering the variety of implementation options, the Legislature should be aware that there are a number of alternatives with either no or modest cost, particularly relative to broad-based incentive programs with multi-million dollar ratepayer costs implemented with many of the states studied. Table 45 provides a summary of low- and no-cost implementation options in different categories. These options may be implemented in various market stages described further below in Subsection 0. For example, some are commonly deployed early in a market preparation phase. The Legislature may choose to implement some of the options early on to create leverage for solar PV support at a relatively low cost. Several options are more suitable for later stages when the solar market has reached a certain level of penetration, and can be deployed to drive down costs in concert with phase-down of direct incentives. It should be noted that, while most of these options require little funding compared to direct incentives, some – such as 'green bank' programs - may require an initial injection or allocation of funds that can be re-circulated in later stages.

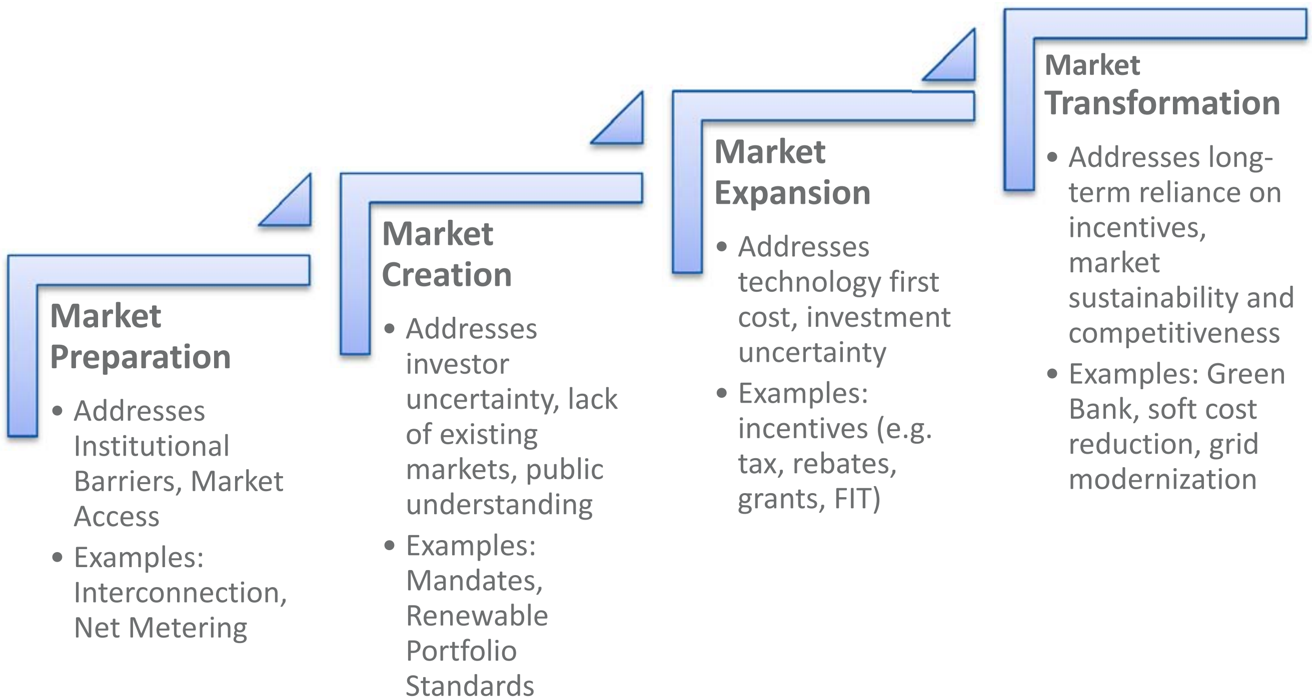
Table 45 – Low- and No-Cost Implementation Options

Category	Subcategory	Implementation Examples
Finance Enabling Policies		Non-Subsidized Solar Loan Programs
		On-Bill Financing
		PACE Financing
		Utility Ownership
		Solar Lease and/or Third-Party Ownership Enabling Policies or Eligibility in Other Policies
Rules & Regulations	Removing Institutional Barriers	Interconnection Standards
		Solar Access Laws
		Business Formation/Financing Laws (e.g. Securities Registration, Innovative Market Structures, such as Crowd-Funding, Cooperatives, Community Solar, etc.)
		Permitting Standardization, Simplification, and Streamlining, and Other “Soft-Cost Reduction” Strategies
	Building Codes	Solar-Ready Building Standards, Zero-Energy Capable Home Standards
	Tax	Property Tax Exemption or Special Rate
		Sales Tax Exemption
		Property Tax/PILOT Standardization or Simplification
Rate Design	Other Rate Design	
Industry Support		Customer Acquisition Cost Reduction (e.g. Solarize Initiative)
		Outreach/Education/Public Information/Voluntary Market Encouragement
		Public Sector Leadership and Demonstration (e.g. Solar on Schools)
		Installer Training and/or Certification

Implementation Sequencing

Another observation is that, based on analysis of state experiences, staging implementation in a particular order can enhance the effectiveness and the cost-effectiveness of solar deployment. The following implementation framework is the authors' adaptation of National Renewable Energy Laboratory's "Framework of Policy Stacking." It illustrates a path of policy ordering commonly adopted by states. (Krasko & Doris, 2012).

Figure 35 – Sequencing Solar Implementation[97]



Market Preparation

The first stage of the framework begins with **"Market Preparation"** strategies. These include a variety of implementation strategies that fall under our broad categories of finance enabling policies, rules and regulations for removing institutional barriers, rate design and industry support strategies. Market preparation strategies are not designed *explicitly* to stimulate growth towards any particular goal or target. Instead, they focus on standardizing market access and removing institutional barriers of entry to the market (Krasko & Doris, 2012). As such, market preparation strategies are typically low-cost and can be executed without significant programmatic changes.

[97] Adapted from (Krasko & Doris, 2012). The authors added the Market Transformation stage.

Market preparation strategies perform several key functions in enabling access to the solar market:

- **Removing technical and legal barriers to solar PV implementation.** Interconnection standards establish the technical and legal procedures for solar PV to integrate to the electric grid. It is an important enabling policy that allows solar PV to participate in the electricity market. Besides interconnection standards, states can adopt permitting rules and regulations that protect solar system owners by (i) ensuring customer's right to solar installations and (ii) reducing the risks, time and cost associated with solar development. Examples include solar access laws and permitting simplification, standardization and streamlining. Additionally, a state may implement installer training or certification programs to standardize and regulate solar installation procedures, or building inspector training to ready local governments for increasing prevalence of initially unfamiliar, but well-understood, installations.
- **Creating a reasonable mechanism for compensating distributed solar generation.** Net metering policies establish the crediting systems for the excess generation being sold back to the grid. As discussed in earlier Sections, net metering is a critical funding source for residential and small business customers and is a key engine for solar development in many states.
- **Lowering the cost of market entry.** To enable affordable access to the solar market, and hence, broaden the scale of market participation, the Legislature may wish to consider market preparation strategies designed reduce the upfront cost of solar installations. Potential implementation options include finance enabling policies (e.g. non-subsidized or indirectly subsidized solar loans, PACE financing and on-bill financing) and tax exemption policies (e.g. property tax exemptions, special property tax rates and sales tax exemptions). It should be noted that while most of these options have minimal budgetary demand, some indirectly subsidized loans may require initial injections or allocations from the state. Alternatively, the state may consider enabling other market/finance approaches such as solar leases, third-party sales agreements, community-solar, and crowd-funding by adopting enabling policies or implementing eligibility requirements in other policies that are already in place.

Market Creation

"Market Creation" strategies demonstrate the state's long-term commitment to support solar PV, and hence, strengthen confidence for widespread private investment. (Krasko & Doris, 2012). Market creation strategies serve three main purposes:

- **Creating stable and predictable long-term demand for solar PV.** RPS is a typical approach to stimulate confidence in the renewable energy market. By mandating a certain portion of retail electricity sales to be met by renewables, RPS creates a predictable long-term demand and revenues for such resources. As discussed in previous Sections, to date solar PV is seldom active in traditional technology-neutral RPS markets outside the sunbelt. A more effective mechanism for stimulating solar investment is to implement an explicit solar tier or solar set-asides, as evidenced in Massachusetts, Delaware, Maryland and New Jersey. In order to successfully drive solar development, incentive levels (i.e. ACP schedules) would need to allow for price levels sufficient to support solar economics. The Legislature may also wish to consider price supporting mechanisms and market segment limitations to direct supply and control price volatility.

- **Creating long-term funding mechanism to support solar PV initiatives.** In order to show long-term commitment and prepare for the next market phase, states may decide to establish a long-term mechanism dedicated to generating funding for solar PV initiatives. An example is to create a public good fund dedicated to supporting solar PV efforts. More commonly, states choose to mandate a certain percentage of an existing or new renewable energy fund or Regional Greenhouse Gas Initiative (RGGI) proceeds be allocated to funding solar initiatives through legislation. Once a funding mechanism is in place, the Legislature may also wish to create a mandate or adopt other strategies to protect the funding from budget raids.

Market Expansion

"Market Expansion" strategies are designed to scale-up market deployment by increasing market access and expanding market coverage. Solar PV cost is not static or independent from the market. There are substantial economies of scale impacting solar PV cost other than module prices. Most states that have sought to implement support for PV have undertaken some level of programmatic or policy initiatives to get market to scale, which have included targeted incentives. Such initiatives are implemented with the intent to achieve a scale to the state's PV industry that accelerates market transformation along a trajectory towards post-incentive sustainability. Performance-based incentives, such as FITs, Standard Offer PBIs and long-term competitive PPAs can also be deployed to create sufficient revenue predictability to attract low-cost financing or reduce the cost of financing. Further, some market expansion strategies are targeted to certain market sectors of public interest (e.g. low-income housing sector, municipal sector, brown fields, capped landfills, etc.).

Market expansion strategies can require substantial funding support from ratepayers, taxpayers or other sources. In order to implement solar PV cost-effectively, the Legislature may wish to utilize the Value of Solar study to help develop an incentive level that increases solar penetration and promotes implementation objectives, at a compensation level in line with the value of distributed solar energy. Further, the Legislature may consider applying a combination of incentives that target various stages of project development and market sectors. Table 46 summarizes the typical roles of various incentive options in the solar PV market. The "Development Stage" column illustrates whether an incentive is designed to provide upfront, short-term or long-term incentives. The "Market Sector" column identifies which sector the incentive typically supports.

Table 46 – Summary of Typical Roles of Incentive Options in the Solar PV Market

		Development Stage	Market Sector
Direct Financial, Up-front (a.k.a. Nameplate Capacity-Based/Denominated) Incentives	Grants, Rebates, or Buy-Downs	Upfront	Residential and small C&I sectors
Direct Financial, Performance-Based Incentives	Feed-In-Tariffs, Standard Offer Contracts or Tariffs, or PBIs (RECs, Energy, or Capacity)	Depends on how program is designed; could be short-term or long-term	All; but typically available to residential and small C&I sectors
	Competitive Long-Term PPAs	Long-term	Large- and utility-scale sectors
	Long-Term Value of Solar Tariffs	Long-term	Typically residential and small C&I sectors
	Technology-Specific “Avoided Costs”	Depends on how program is designed; could be short-term or long-term	Depends on how program is designed; could be available to all sectors
Expenditure-Based Tax Incentives	Investment Tax Credits	Upfront	All
Production Tax Incentives	Production Tax Credits	Long-term	All

In additional to incentives, the legislature may wish to implement strategies that expand solar PV implementation and fulfill other important state objectives. Virtual net metering and community-shared solar/net metering can accelerate solar PV penetration by opening up the market for substantial investment to include participations by ratepayers whose specific situation is not conducive to investing in on-site solar (reasons might include renting, orientation, shading, etc.). Outreach, education and public sector leadership campaigns may also increase awareness of solar PV, opening the market to further opportunities. States may also wish to consider strategies that ensure the economic benefits of increased solar investment are captured within the state. Examples of such implementation options include local content bonus or mandates and direct incentives for in-state solar businesses.

Market Transformation

As the market approaches to a scale, states may wish to implement options that drive down installed cost as incentives are being scaled down. The goal of **"Market Transformation"** strategies is to attract sufficient private investment to achieve a certain market scale that can operate healthily without substantial ratepayer or taxpayer subsidies (or while allowing a step-down of direct support over time). Market transformation strategies include a variety of innovative options, many of which have relatively low-cost or require only initial capital injections that can be re-circulated. Market transformation strategies have several common purposes:

- **Driving down solar PV cost such that it can become competitive with other technologies.** As market penetration increases and incentives are phase down, the Legislature may wish to consider implementation options that focus on driving down the cost of solar PV but which are best deployed within markets with sufficient scale, to help solar compete more effectively with other renewable technologies in the absence of additional incentives. There is a broad spectrum of implementation options targeted to bring down various cost components of solar PV (e.g. module prices, soft costs, operation & maintenance costs, etc.). Recent literature has illuminated implementation options states can execute to reduce soft costs associated with customer acquisition, permitting and inspection, and installation labor. Examples include Solarize Initiatives, bulk-purchasing, education/outreach campaigns, online permit application procedures, and solar-ready building codes.
- **Phasing down market reliance on incentives by leveraging private investment.** An example of an implementation option designed to such objective is establishing a Green Bank and deploying an associated suite of programs. A Green Bank typically uses public funds to attract and leverage for increased private investment, allowing the program to ultimately operate as a self-sustaining institution without public subsidies. By implementing a Green Bank states can also choose to offer a variety of financing tools and products targeted to address different barriers in the market, and thereby fill gaps in the financing market.
- **Enhancing the physical infrastructure for solar PV implementation to prepare for widespread adoption.** As solar penetration increases and broadens, states may wish to consider enhancing existing grid architecture to advance solar PV implementation. Such initiatives could be a combination of rules, regulations and incentives that support micro-grids, smart-grid and other DG-friendly infrastructures.

Interactions

While most of the implementation options identified in this study could be executed concurrently - and in the laboratory of the states, nearly all options have been tried in combination somewhere- the Legislature may wish to consider distributed solar implementation options that are synergistic. This includes executing a combination of implementation options that address various market barriers and provide sufficient incentives that attract solar investment. Meanwhile, the Legislature should be mindful of selecting a cost-effective and administratively effective suite of implementation options that avoids needless duplication and aims for simplicity, transparency, clarity, and consistency with underlying policy objectives.

Other Considerations

In addition to the various issues discussed in the sections above, we have identified a list of considerations that should be taken into account when developing a comprehensive implementation approach:

- Implementation options selected (if any) should align as best possible with the legislature's definition of objectives. For example, if the state's policy objective is to increase installed solar PV capacity, the legislature needs to consider whether selected implementation options support actual installations (i.e. does the strategy yield a high project success rate). If the objective is to support in-state economic development and job growth, then the implementation option might target support for local manufacturers and contractors, and also encourage installations by local developers instead of favoring national players. Because policy objectives like those delineated in Table 44 can conflict - specific implementation options can maximize one objective while working counter to another - it is important that the legislature understand the tradeoffs among these options. (Grace, Donovan, & Melnick, 2011) (New York State Energy Research and Development Authority, 2012).
- The Legislature may wish to create leverage with polices and initiatives already in place in other states and the region to support solar investment and deployment in Maine. For example, in the absence of a local RPS market, Vermont solar system owners are able to finance their projects through a combination of revenues from the state's net metering program and the sales of RECs to Class I markets in other New England states (e.g. Massachusetts and Connecticut). The Maine legislature may choose to adopt implementation options that synergize with the regional solar market infrastructure.
- Implementation objectives and options are subject to constraints. For example, Federal preemption via the supremacy clause of the US constitution[98] may impact the legislature's choice when considering implementation options with in-state geographic eligibility requirements.[99] Other constraints, such as siting feasibility and grid interconnection constraints, may affect how the market responds to the implementation option.

98 Federal law may limit some approaches to standard offer PBIs, relating to PURPA and the Federal Power Act (Hempling, Elefant, Cory, & Porter, 2010).

99 The commerce clause may impact the ability of a policy to limit eligibility to in-state generation (Elefant & Holt, 2011).

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