APPENDIX D: COMPONENTS OF COST/BENEFIT ANALYSIS

As noted in Section 1, this study is intended to explore the relative, in tandem with the overall, costs and benefits associated with net energy metering. As noted in the final Task Force Framing Memorandum,

The language in the legislation regarding "costs and benefits" is not intended for us to evaluate the costs and benefits of achieving this 1600 MW goal, but directs ***us to consider the relative costs and benefits of policy options to achieve the goal****, as well as the overall cost and benefits of the existing net metering framework from the perspective of multiple customer groups.*

More specifically, this analysis illustrates how these costs and benefits compare, in both relative and overall terms, across different alternative policy futures, from the four cost-benefit perspectives (non-owner participant, customer-generator, non-participating ratepayers, and citizens of Massachusetts at large) described in Section 1.2.

D.1 Overview of Cost Benefit Categories and Subcategories

The cost and benefit framework addresses seven broad categories of costs and benefits. These seven categories can be subdivided into two groups, as follows:

D.1.1 Ratepayer & Participant Costs and Benefits

Ratepayer and participant cost and benefit impacts experienced directly include those incurred and accruing to both participants and non-participants in solar and net energy metering policies. They fall into four categories as follows:

- **Solar PV System Costs**: The direct costs associated with PV systems;
- **Solar Policy**: Massachusetts' (and Federal) public policies and programs related to renewable energy and solar PV;
- **Behind-the-Meter (BTM) Solar Production within a Billing Month**: The on-site and "behind the meter" solar PV production that reduces customer bills during the billing month; and
- **Net Metering Credits (NMC, from Net Metering Beyond the Billing Month & Virtual Net Metering (VNM)**: Net metering credits gained by customers as a result of solar PV production exceeding a customer's usage during a given month from an on-site or remote VNM installation.

These costs and benefits will differ significantly across the alternative policy futures explored in this study, particularly given that SREC, Policy Path A and Policy Path B have very different solar PV incentive structures and approaches dealing with net metering credits. In addition, each of these categories has multiple subcategories of costs and benefits, which have a diverse array of impacts on the four cost-benefit perspectives analyzed.

D.1.2 Secondary Costs and Benefits

In addition to the net ratepayer and participant values, solar PV can also cause three broad categories of costs and benefits to accrue broadly to each of the four perspectives on a secondary market and societal basis. Specifically, solar PV can result in secondary impacts to:

- **Electric Market(s)**;
- **Electric Investment Impacts**; and
- **Externalities and Other Impacts**.

These impacts are primarily a function of the amount of solar PV installed in Massachusetts, and therefore will be quite similar across the different scenarios to the extent that they each reach 2500 MW in a similar timeframe. To the degree their values differ, this will be primarily driven by the variation in solar PV deployment between the futures studied.

D.2 Cost and Benefit Components and Level of Analysis

Within each of these categories, there are a number of individual cost and benefit components that comprise the individual impacts to be considered. Table 10 below illustrates the subcategories associated with these three categories of secondary costs and benefits. A color coding of these broad categories by color code and hue is used throughout to aid the reader in following the various components of this complex analysis.

Table 30: Cost and Benefit Categories and Components

Category	Subcategory	Code	Analysis
PV System Costs	System Installed Costs	CB1.1	Quantitative
	Ongoing O&M + Insurance Costs	CB1.2	Quantitative
	Lease Payments	CB1.3	Quantitative
	PILOTs / Property Taxes	CB1.4	Quantitative
	ROI (to lenders & investors)	CB1.5	Quantitative
	MA Residential RE Tax Credit	CB1.6a	Quantitative
	MA Income Taxes	CB1.6b	Quantitative
	Federal Incentives (ITC)	CB1.7a	Quantitative
	Federal Income Taxes	CB1.7b	Quantitative
Solar Policy	Direct Incentives	CB2.1	Quantitative
	Other Solar Policy Compliance Costs	CB2.2	Quantitative
	Displaced RPS Class I Compliance Costs	CB2.3	Quantitative
	Solar Policy Incremental Admin. & Transaction Costs	CB2.4	Quantitative
Behind-the-Meter Production During the Billing Month	Generation Value of On-site Generation	CB3.1	Quantitative
	Transmission Value of On-site Generation	CB3.2	Quantitative
	Distribution Value of On-site Generation	CB3.3	Quantitative
	Other Retail Bill Components (Transition, EE, RE)	CB3.4	Quantitative
Net Metering Credits Beyond the Billing Month	Offsetting On-site Usage	CB4.1	Quantitative
	Virtual NM	CB4.2	Quantitative
	Wholesale Market Sales	CB4.3	Quantitative
	Virtual NM Administrative Costs	CB4.4	*Qualitative*
Electric Markets	Wholesale Market Price Impacts – Energy	CB5.1	Quantitative
	Wholesale Market Price Impacts – Capacity	CB5.2	*Qualitative*
	Avoided Generation Capacity Costs	CB5.3	Quantitative
	Avoided Line Losses	CB5.4	Quantitative
	Avoided Transmission Tariff Charges	CB5.5	Quantitative
Electric Investment Impacts	Avoided Transmission Investment - Remote Wind	CB6.1	Quantitative
	Avoided Transmission Investment – Local	CB6.2	Quantitative
	Avoided Distribution Investment	CB6.3	Quantitative
	Avoided Natural Gas Pipeline	CB6.4	*Qualitative*
Externalities and Other	Avoided Environmental Costs CO_2, NO_x and SO_x	CB7.1	Quantitative
	Avoided Fuel Uncertainty	CB7.2	*Qualitative*
	Resiliency	CB7.3	*Qualitative*
	Impact on Jobs	CB7.4	*Qualitative*
	Policy Transition Frictional Costs	CB7.5	*Qualitative*

Given the scope, tight timelines, limited budget, and other practical limitations, not all of costs and benefits of solar PV are quantified herein. This is the case, in part, because the data needed to undertake a study of this type requires a wide variety of data sources that may or may not be easily or reliably quantified. As a result, this study includes a mix of three types of data:

- **Quantitative** data derived from detailed analysis for the purposes of this study.
- <u>Parametric</u> assumptions that represents an "educated guess" made in order to estimate the impact when quantitative data is difficult to verify or unavailable (later, we run sensitivity analyses on many of these parametric assumptions in order to assess the potential impact of uncertainty for the applicable components); and
- *Qualitative* data and information that represents a generalized assessment of a particular category and/or sub-category of costs and benefits, but not included in the summation of cost of benefit.

Certain major outputs included in more expansive economic analyses that are not fully quantified in this analysis include:

- **Indirect macroeconomic impacts**, which (in this case) include the costs and benefits incurred broadly outside of the solar industry as a result of current policies and alternative policy futures;

- **Induced macroeconomic Impacts**, or the changes in spending, economic behaviors or habits as a result of the direct and indirect costs and benefits.

Impacts identified as addressed qualitatively will be discussed in a generalized sense later in this report. Table 10 shows which cost and benefit components are quantified, and which are dealt with qualitatively.

In order to clearly illustrate the "flows" or distribution of costs and benefits associated with each policy future, each component of costs and benefits discussed in this section has a table describing how that cost and benefit category manifests as either a cost or benefit (or both) from each of the four perspectives. These tables also identify whether quantitative or qualitative analysis is performed for this study, and in some instances, whether a parametric assumption is used in estimating a quantified impact; the manner in which it is being used, and whether the result accrues as a benefit, cost, or is not considered to be either from each of the four cost-benefit perspectives. Table 11 below presents a key to understanding when each type of data is being used, and if that result is a cost or benefit to the perspective in question, within the sections that follow.

Table 31: Key to Cost and Benefit Description Tables

Classification	**Benefit**	**Cost**	N/A
Type of Information	**Quantitative (Bold)**	<u>Parametric</u> (Underlined)	*Qualitative* (italics)

D.3 Category 1: PV System Costs

The first major category of costs and benefits considered in this analysis are associated with the cost of grid-tied solar PV systems eligible for net metering. The nine subcategories of costs and benefits contained within PV system costs are as follows

Subcategory	Code	Analysis
System Installed Costs	CB1.1	Quantitative
Ongoing O&M + Insurance Costs	CB1.2	Quantitative
Lease Payments	CB1.3	Quantitative
PILOTs / Property Taxes	CB1.4	Quantitative
ROI (to lenders & investors)	CB1.5	Quantitative
MA Residential RE Tax Credit	CB1.6a	Quantitative
MA Income Taxes	CB1.6b	Quantitative

Federal Incentives (ITC)	CB1.7a	Quantitative
Federal Income Taxes	CB1.7b	Quantitative

For ease of estimation, PV system installed and operating costs are assumed to be independent of the specific state policy futures, primarily driven by global module markets and local scale economies.[23] These costs vary by installation type and in some cases ownership model, but are held constant across alternative policy futures. When calculated installed costs throughout the baseline policy and alternative policy futures, the total costs per year can be stated as:

$$\sum_{ij} kW_{ij} * \$ / kW_i$$

where

i = type of installation; and j = the associated EDC territory.

For operating & maintenance costs, insurance, lease payments, and property taxes, a similar formula s used:

$$\sum_{ij} kW_{ij} * \$ / kWyr_i$$

Table 12 below illustrates how these subcategories accrue as direct costs or benefits to the four perspectives analyzed.

Table 32: PV System Cost Applicability to Analysis Perspectives

Perspective	Subcategories Accruing as Benefits to Some or All With Perspective	Subcategories Accruing as Costs to Some or All With Perspective
Non-Owner Participants **(NOP)**	Lease Payments PILOTs/Property Taxes	MA and Federal Income Taxes
Customer-Generators **(CG)**	ROI to Lenders/Investors MA Residential RE Tax Credit Federal Incentives (ITC)	System Installed Costs Lease Payments PILOTs/Property Taxes MA and Federal Income Taxes
Non-Participating Ratepayers **(NPR)**	MA Income Taxes	Federal Income Taxes Federal Incentives (ITC) MA Residential RE Tax Credit
Citizens of the Commonwealth at Large **(C@L)**	System Installed Costs Lease Payments PILOTs/Property Taxes	Federal Income Taxes

[23] This analysis Ignored potential differential impacts on installed costs related to what might be referred to as "installer incentive capture". It does not explicitly assume or analyze installed cost inflation under the more 'generous' policy options (compared to less generous policies), an installer 'incentive capture' phenomenon cited by some analysts, or assume lower installed costs for policy futures with less generous combined solar and NM incentives.

	MA Income Taxes ROI to Lenders/Investors	

D.3.1 System Installed Costs

System installed costs include the total upfront capital cost (and the replacement of the inverter) for solar PV systems installed in Massachusetts under the net energy metering program.

To understand the variation in installed costs, the analysis utilizes an installed cost forecast, as derived for each subsector. The costs were then further differentiated by project size and the type of solar PV installation in question. The initial installed cost that served as the basis for each subsector forecast is based on historic data from both publicly-available sources, as well as with data obtained through supplemental research. The costs of interconnection are assumed to increase at the rate of inflation, and (for ease of estimation) the inverter replacement is assumed to be covered by the initial 25-year warranty included in the upfront system cost.

The assumptions used in projecting PV system installed costs are detailed in Appendix A.

Overall, the total cost associated with solar PV systems will be borne by the customer-generator as the owner and investor in the system, while the in-state share of that total cost comes as a benefit to the citizens of Massachusetts at large. The distribution of these costs does not vary across the differing policy futures. The table below outlines the costs and benefits accruing to the four perspectives.

Table 33: PV System Installed Cost Impacts by Perspective

Policy	Participants		Non-participating Ratepayers	Citizens of MA at Large
	Non-Owner Participants	Customer-generator (CG)		
All	n/a	**Total Cost**	n/a	% total cost retained in state [1] *Macroeconomic impacts [2]*
Notes:	[1] Insufficient data/time for detailed analysis; explored parametrically. Potential area for further study. [2] Beyond scope; Potential area for further study			

D.3.2 Ongoing O&M and Insurance Costs

Ongoing operations and maintenance (O&M) and insurance costs include the fixed O&M, as well as the cost of insuring a solar PV system (typically to ensure financing), for PV systems of all sizes.

In a way similar to the installed cost estimates, the O&M cost estimates utilized in this analysis have been derived for each subsector through the use of publicly-available data, supplemented by additional research using private sources. All O&M costs are reported as a fixed $/kW-year, escalating annually at the rate of inflation. No variable O&M costs were modeled. To calculate annual insurance expenses, the cost was estimated as a specified percentage of the total project cost. The cost of project management was considered separately.

The costs of ongoing O&M and insurance are borne in all policy futures by the customer-generator, while benefits accrue in all scenarios to eligible non-owner participants and MA citizens at large. The table below illustrates the distribution of the costs and benefits across the four perspectives under consideration.

Table 34: Ongoing O&M + Insurance Costs Impacts by Perspective

Policy	Participants		Non-participating Ratepayers	Citizens of MA at Large
	Non-Owner Participants	Customer-generator (CG)		
All	n/a	**Total Cost**	n/a	% total cost retained in state [1] *Macroeconomic impacts [2]*
Notes:	[1] Insufficient data/time for detailed analysis; explored parametrically. Potential area for further study. [2] Beyond scope; Potential area for further study			

D.3.3 Lease Payments

The lease payments subcategory represents the total value of lease payments paid to land or other property owners for systems greater than 25 kW for the right to lease the land upon which a solar PV system is sited.

The analysis assumes a range of lease payment costs ranging from $12-$14/kW per year for systems over 25 kW. This assumption was developed through market analysis, which allowed for the appropriate benchmarking of this range of costs. Calculation of the impacts of lease payments were limited to systems over 25 kW, given that systems under 25 kW (including residential & small commercial roof-mounted systems, or commercial emergency power installations) tend not to require the lease of land, or are roof-mounted on a customer generator or non-owner participant's property. Lease payments are only considered in the analysis of costs and benefits insofar as the lease payments are additive to estimated PPA or VNM discounts to 3rd-party owned system hosts. These costs were held constant across the baseline scenarios, as well as across all alternative policy futures examined.

Overall, benefits associated with lease payments accrue to non-owner participants, as therefore also to citizens of Massachusetts at large. The costs are solely borne by customer-generators, and do not affect non-participating ratepayers. The distribution of these cost and benefit impacts do not change in either of the alternative policy scenarios. The table below illustrates the cost-benefit impacts of lease payments for systems over 25 kW by relevant cost-benefit perspective.

Table 35: Land Lease Payments Impacts by Perspective

Policy	Participants		Non-participating Ratepayers	Citizens of MA at Large
	Non-Owner Participants	Customer-generator (CG)		
All	**Payments [1]**	• **Assume: HO = 0; Non-VNM = 0** • **3PO VNM only: assume X% of installations pay lease (when host ≠ off-taker) [2]**	n/a	**Payments [1]** *Macroeconomic impacts [3]*
Notes:	[1] receipt of lease payments . 100% Stay in-state [2] x% = parametric assumption; 1-x% = no lease (value embedded in offtake discounts) [3] Beyond scope; Potential area for further study			

D.3.4 Payments in Lieu of Taxes (PILOTs)/Property Taxes

Property taxes and PILOTs are payments to local governments paid by the owner of property and/or land within their jurisdiction. These payments apply to solar PV systems, to the extent that systems are not exempt from paying them.

In general, the treatment of property taxes and PILOTs treatment varies widely across the Commonwealth. Thus, the assumptions for this analysis were developed through extensive market analysis and benchmarking. The results of this benchmarking exercise support a base case assumption of $10/kW-year. As with lease payments, when the landowner or NMC offtaker is also the taxing authority, PILOTs and property taxes are only considered insofar as the lease payments are additive to the our estimates of NMC or PPA discounts.

The costs associated with PILOTs and property taxes are borne by customer-generators, but the net local government revenue results generally in direct benefits for citizens at large, and do not affect non-participating ratepayers. The table below illustrates the distribution of related costs and benefits.

Table 36: PILOTs / Property Taxes Impacts by Perspective

Policy	Participants		Non-participating Ratepayers	Citizens of MA at Large
	Non-Owner Participants	Customer-generator (CG)		
All	**Payments**	• **On-site load & HO: assume exempt** • **If 3PO, (i) if host = off-taker, assume embedded in discount; (ii) otherwise assume Prop. Tax or PILOT payment made**	n/a	**Payments** *Macroeconomic impacts* [1]
Notes:	[1] Beyond scope; Potential area for further study			

D.3.5 Aggregate Return to Debt & Equity

The aggregate returns to debt lenders and equity investors constitutes the difference between revenue and costs necessary to provide sufficient rents/profits to the customer-generator system owners and/or investors to induce investment. As such, it is **NOT SHOWN** in the tallying of costs and benefits; rather, it is represented as the difference between calculated costs and benefits. It was necessary however, to calculate the before tax returns to investors in order to estimate tax liabilities, and in addition, to estimate the proportion of these returns retained in state (a benefit from the perspective of citizens at large).

For the purposes of this analysis, the returns to lenders and/or equity investors is the sum of 1) the debt interest, 2 the required returns for meeting the threshold rate of return for investment, and 3) the economic rents/profits made by the system's owners. The analysis assumes that the returns are the net present value of total project revenue, less the net present value of the total costs, and will, in sum, vary across policy futures.

These returns do not come at a direct cost to any perspective. The portion retained in state is a benefit to customer-generators and citizens at large through enhanced economic activity, without affecting non-owner participants or non-participating ratepayers. The nature of these flows is consistent across policy futures, and is illustrated in the table below.

Table 37: Aggregate Return to Debt & Equity Impacts by Perspective

Policy	Participants		Non-participating Ratepayers	Citizens of MA at Large
	Non-Owner Participants	Customer-generator (CG)		
All	n/a	**Calculated value of revenue - cost**	n/a	30% total payments retained in state [1] *Macroeconomic impacts [2]*
Notes:	[1] **Percentage difficult to determine and may evolve; explored parametrically. Potential area for further study. Use 30% and explore sensitivity.** [2] Beyond scope; Potential area for further study			

D.3.6 Massachusetts Residential Renewable Energy Tax Credit

The Massachusetts residential renewable energy tax credit is a tax credit taken on the value of a solar PV system by customer-generators who host a system they own. Since the credit is only open to the owner or tenant of a residential property, it cannot be monetized by 3rd-party customer-generators.

The state tax credit is equal to the lesser of 15% of the total system cost or $1,000. Any tax credits in excess of the value of an individual taxpayer's total tax liability present in the first year may be carried forward to future tax returns for three years. Given that the total number of residential solar PV customers will vary considerably across policy futures, the total value of this tax credit will also vary accordingly.

The state tax credit accrues as a benefit to residential host owners only, while coming as a cost to non-participating ratepayers in the form of the non-participant's share of the cost of the tax credit. The assumption is that benefits and costs associated with the tax credit net to zero for the citizens of Massachusetts at large, which include both participants and non-participants alike. The table below shows the distribution of these costs and benefits.

Table 38: MA Residential RE Tax Credit Impacts by Perspective

Policy	Participants		Non-participating Ratepayers	Citizens of MA at Large
	Non-Owner Participants	Customer-generator (CG)		
All	n/a	**Res HO Only: offset to system installed cost**, *less participant's share of tax payments*	**Total Tax Payments** * *non-participants share of tax payments*	**Assume all retained in state, net to zero**
Notes:	Everyone including participants assumed to be a taxpayer			

D.3.7 Massachusetts Income Taxes

The Massachusetts state income taxes used in this analysis comprise the net value of taxes paid to the state as a result of solar PV eligible for net energy metering.

In order to calculate the direct costs and benefits of paying Massachusetts income taxes, the analysis assumes that a solar PV project's taxable income increases as revenues increase, and decreases based on expenses and depreciation. Overall, the analysis contains several assumptions related to individual and corporate taxation. First, it is assumed that individuals and government entities cannot depreciate their assets for the purpose of taxation, nor are they subject to income tax related to project revenue or savings associated with savings from PPAs and net metering credits. In terms of business taxpayers, it is assumed that all eligible taxpayers have the "tax appetite" (meaning a sufficient degree of taxable income) to take full advantage of the credit, as well as accelerated depreciation. The analysis also assumed that businesses would be subject to a range of tax rates, from 5.25% for small commercial host-owned systems to 8.25% for private third-party owned systems. Finally, the analysis assumes that private non-residential non-owner participants also will incur increased tax liability, given that increase PPA and net metering credit revenue (as well as potential revenue from lease payments) results in an increase in taxable income as a result of lower operating expenses.

Overall, Massachusetts taxes associated with solar PV systems come as a cost to participants, but accrue as a benefit to non-participating ratepayers. Benefits to the citizens of Massachusetts at large are assumed to net to zero. The table below illustrates the distribution of these costs and benefits across the four key perspectives, under various policy futures.

Table 39: MA Income Taxes Impacts by Perspective

Policy	Participants		Non-participating Ratepayers	Citizens of MA at Large
	Non-Owner Participants	Customer-generator (CG)		
All	**[PPA / NMC discounts and/or lease payments] * MA tax rate [1]**	**Business Only: ((Pre-tax net income less depreciation) * MA tax rate)**	**Total increase in MA tax revenue**	**Assume net to zero**
Notes:	[1] for all other than residents and government entities			

D.3.8 Federal Incentives (Investment Tax Credit)

Federal incentives refer, in this analysis, to the federal investment tax credit (ITC), for which solar PV is currently an eligible technology. The Federal ITC for solar PV systems is 30% of the total value of the system. Under current federal law, the credit for non-residential owners (including third-party owners) will drop to 10%, while the credit residential host-owned systems will drop to 0%. These credit values are maintained across all policy scenarios, given that the credit will be taken (or not taken) independent of Massachusetts' policy choices.

The value of the federal ITC is enjoyed strictly as a benefit in Massachusetts, specifically in terms of lower system costs for customer-generators, as well as the in-state share of the total share of the remaining direct economic value of solar PV systems retained in state to the benefit of the citizens of Massachusetts at large. The table below illustrates the distribution of these benefits.

Table 40: Federal Incentives (ITC) Impacts by Perspective

Policy	Participants		Non-participating Ratepayers	Citizens of MA at Large
	Non-Owner Participants	Customer-generator (CG)		
All	n/a	**Reduction to system installed cost [1]**	n/a	15% total retained in state [2] *Macroeconomic impacts [3]*
Notes:	[1] Ignore MA small increase of Federal taxes dispersed among all Federal taxpayers countrywide. Difficult to determine and small in consequence. [2] Insufficient data/time for detailed analysis; explored parametrically (Assume 15% based on MA as less than 10% of national (conventional) tax equity market, but inclination for some transactions with local source of (unconventional) tax equity). Potential area for further study. [3] Beyond scope; Potential area for further study			

D.3.9 Federal Income Taxes

The federal income taxes used in this analysis comprise the net value of taxes paid to the federal government as a result of solar PV systems eligible for net energy metering. All of the assumptions associated with calculating the impact of Massachusetts state taxes are exactly the same, save for the fact that the taxes in question are paid to the federal government, which also entails different tax rates. The marginal federal corporate and individual tax rate used in this analysis is 35%.

The bulk of the net costs of federal income tax changes fall upon customer-generators and non-owner participants. The cost to customer-generators is the taxable share of their pre-tax net income (less depreciation), while the cost to non-owner participants is represented by the taxable portion of the PPA and net metering credit savings accruing to corporate taxpayers. On net, the analysis thus assumes that federal income tax changes come at a net direct cost (without accounting for any indirect or induced economic impacts) to the citizens of Massachusetts. The table below shows the manner in which these benefits are distributed across the four key perspectives, under various policy futures.

Table 41: Federal Income Taxes Impacts by Perspective

Policy	Participants		Non-participating Ratepayers	Citizens of MA at Large
	Non-Owner Participants	Customer-generator (CG)		
All	**PPA / NMC discounts and/or lease payments * Federal tax rate [1][3]**	**(Pre-tax net income less depreciation) * Federal tax rate [1]**	n/a	**Total Tax payments** [1] *Macroeconomic impacts [2]*
Notes:	[1] Ignore MA small increase of Federal tax receipts dispersed among all Federal taxpayers countrywide. Difficult to determine and small in consequence. [2] Beyond scope; Potential area for further study [3] for all other than residents and government entities			

D.4 Category II: Solar Policy

The second major category of costs and benefits considered in this analysis are associated with the costs associated with complying with Massachusetts' RPS pertaining to solar PV systems eligible for net metering. The four subcategories of costs and benefits part of solar policy costs include:

Direct Incentives	CB2.1	Quantitative
Other Solar Policy Compliance Costs	CB2.2	Quantitative
Displaced RPS Class I Compliance Costs	CB2.3	Quantitative
Solar Policy Incremental Admin. & Transaction Costs	CB2.4	Quantitative

In general, the value of these costs and benefits will vary dramatically across policy futures, given that the incentive components of each policy future vary the most across perspectives. The table below illustrates how these subcategories accrue as direct costs or benefits to the four perspectives analyzed.

Table 42: Solar Policy Impact Applicability to Analysis Perspectives

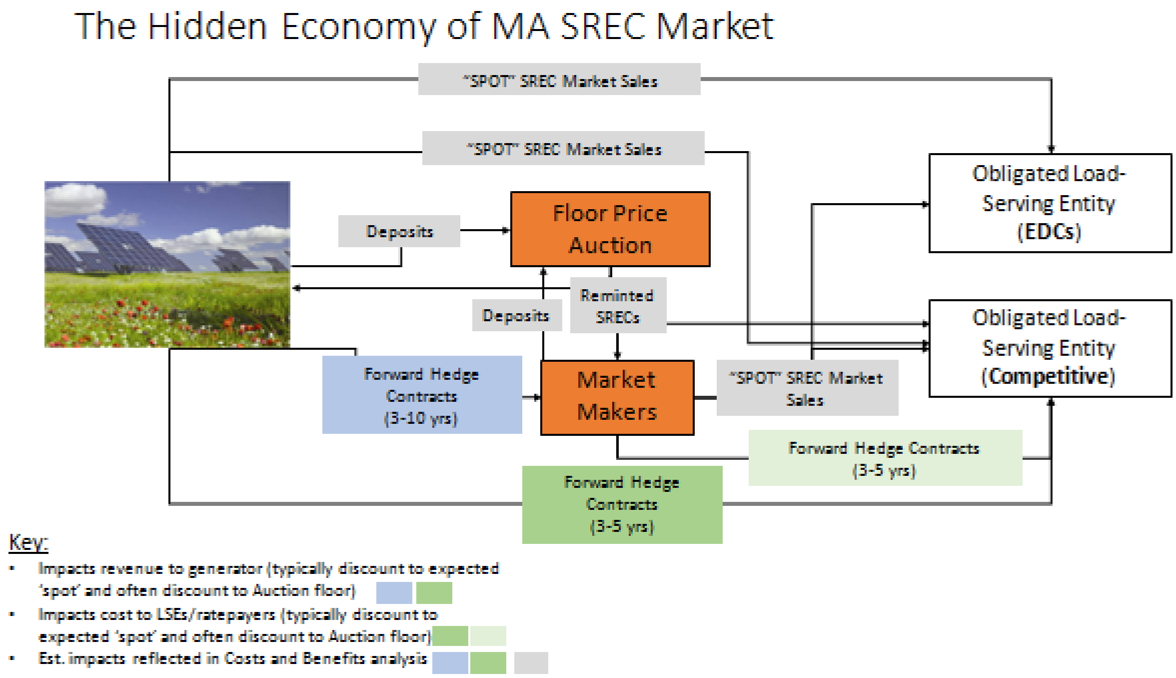
Perspective	Subcategories Accruing as Net Benefits to Some or All With Perspective	Subcategories Accruing as Net Costs to Some or All With Perspective
Non-Owner Participants ***(NOP)***	• N/A	• N/A
Customer-Generators ***(CG)***	• Direct Incentives	• Solar Policy Incremental Admin. and Transaction Costs
Non-Participating Ratepayers ***(NPR)***	• Displaced RPS Class I Compliance Costs	• Direct Incentives • Other Solar Policy Compliance Costs • Solar Policy Incremental Admin. and Transaction Costs
Citizens of the Commonwealth at Large ***(C@L)***	• Displaced RPS Class I Compliance Costs	• Direct Incentives • Solar Policy Incremental Admin. and Transaction Costs

D.4.1 Direct Incentives

Direct incentives include the total incentives directly paid to solar PV projects under all of the policy futures under consideration. Under the extended SREC policy scenario, these incentives take the form of SRECs as well as other incentive payments, including Commonwealth Solar and Solarize incentive payments. Under Policy Paths A and B, these costs will take the form of PBI or EPBI payments, or pass through of gross costs of those payments to ratepayers (netting the value from EDCs reselling energy procured into the market is addressed in other components below). Given the variety of policy futures used in this study, the analysis incorporates a variety of different forms of direct incentives to eligible solar project (including those receiving net metering credits). These incentives are described in detail in Section 2.4.1 and 2.5.1.

To calculate the value of SREC payments, it is important to understand the structure of the existing SREC markets, as well as how a hypothetical program (SREC-III) that extends the basic structure of SREC-I and SREC-II to 2025. Figure 50 is an illustration of the main structural flows and features of the Massachusetts SREC market, underscoring the hedging transactions that result in revenues to generators differing from costs to ratepayers.

Figure 50: Schematic Diagram of Hedging Transactions within the SREC Carve-out Market



To represent these effects, the analysis uses Sustainable Energy Advantage, LLC's proprietary Solar Market Study model to model SREC values based on a supply-responsive demand formula. To estimate policy costs under the alternative Policy Paths A & B discussed in Section 2.4 and 0, SEA developed custom models purpose-built for this analysis.

Nevertheless, the use of supply curves is a common feature to both models. This analysis relies on modeling the economics of over 700 solar PV "supply blocks", which represent the various types of solar PV systems that can be built in Massachusetts and are eligible for applicable incentives, as subdivided by:

- The local EDC territory the project is located in;
- The size and characteristics of the project;
- The ownership structure of the project;
- The rate class of the end-user (or other off-taker); and
- Other appropriate characteristics.

To model the production of these systems, solar PV production data from the National Renewable Energy Laboratory's PVWatts model, which uses Worcester, MA as the proxy location for all system output.

The models used to estimate the total value of applicable incentives uses a proprietary modified version of the publically available Cost of Renewable Energy Spreadsheet Tool (CREST) model, a model designed by SEA for NREL. The model uses a variety of inputs, including fixed capital costs, all applicable project revenues (including uncontracted revenues), as well as financing assumptions, ownership, and the degree of hedged vs. unhedged risk exposure commodity, among many others. Finally, the analysis also assumes that investors value post-incentive Class I RPS RECs in their pro formas at $5/MWh. The supply curve assumptions are discussed further in Appendix A.

Table 43: Direct Incentives Impacts by Perspective

Policy	Participants		Non-participating Ratepayers	Citizens of MA at Large
	Non-Owner Participants	Customer-generator (CG)		
SREC	Assumed N/A	**Solar incentive revenues (taking into account LSE hedging) + CommSolar+Solarize Payments**	**Solar incentive payments (taking into account LSE hedging) + CommSolar+Solarize Costs**	**Solar incentive payments (taking into account LSE hedging) + CommSolar Costs [1]** *Macroeconomic impacts [2]*
A & B		**Incentive Payments**	**Funding of Incentive Payments**	**Funding of Incentive Payments** *Macroeconomic impacts [2]*
Notes:	[1] Assume all transaction costs, market maker margins and payments to run auction leave the state [2] Beyond scope; Potential area for further study			

D.4.2 Other Solar Policy Compliance Costs

Solar policy compliance costs outside of direct incentives include the solar alternative compliance payment (SACP) revenues collected by DOER. Under Policy Paths A and B, these revenues would not be collected, as the SREC program would be replaced by the new incentive regimes described in Sections 2.3, 2.4 and 0.

Both historic and projected SACPs were utilized in calculating the baseline SREC policy scenario. The total quantity of SACPs needed under SREC-I, SREC-II and SREC-III was calculated using SEA's proprietary Massachusetts Solar Market Study Model. Speciifc assumptions are included in Appendix A.

Table 44: Other Solar Policy Compliance Costs Impacts by Perspective

Policy	Participants		Non-participating Ratepayers	Citizens of MA at Large
	Non-Owner Participants	Customer-generator (CG)		
SREC	N/A	N/A	**SACP**	**SACP – DOER expenditures in State = 0** [1]
A & B	N/A	N/A	N/A	N/A
Notes:	[1] assume all DOER SACP $ spent in state			

D.4.3 Displaced RPS Class I Compliance Costs

In any of the policy futures considered, the SREC or REC created obviates the need for, or serves to fulfill, a unit of Massachusetts Class I RPS compliance. Solar PV production can displace RPS Class I compliance costs in two ways: 1) through eliminating the need to purchase non-solar Class I RECs (by meeting the Solar Carve-Out or minting a Class I solar REC), and 2) via behind-the-meter production (and instantaneous consumption) that reduces overall load. Thus, under the "SREC Policy" future, the analysis assumes that SRECs purchased avoid non-solar Class I purchases, as do the Class I RECs purchased via the upfront and performance-based incentives in place under Policy Path A and B.

For each policy future, cases are considered in which either 1) the Solar Carve-Out displaces Class I wind RECs or 2) displaces payments of Class I ACPs under a shortfall in Class I RPS supply.

Table 45: Displaced RPS Class I Compliance Costs Impacts by Perspective

Policy	Participants		Non-participating Ratepayers	Citizens of MA at Large
	Non-Owner Participants	Customer-generator (CG)		
SREC, A & B	N/A	N/A	Avoided Class I RPS Costs	Avoided Class I RPS Costs
Notes:				

D.4.4 Solar Policy Incremental Administrative and Transaction Costs

SEA modeled incremental solar policy administrative and transaction costs as discussed in Appendix A. The costs in Appendix A represented the estimated one-time and ongoing costs for a single large EDC (National Grid or Eversource, and were scaled up to apply to the entire Massachusetts market. Costs in this category for SREC policies are built into SEA's proprietary MA Solar Market Study model. In addition, under Policy Path A, developers seeking incentives must compete for PBIs, and (based on experience elsewhere) must incur costs to make more than one sale (to a host), on average, in order to secure incentives for winning bids. This 'dry hole' cost represents additional overhead compared to an open incentive in which developers must make one sale per incentive contract. The estimate of these costs is detailed in Appendix A.

Table 46: Solar Policy Incremental Admin. & Transaction Costs Impacts by Perspective

Policy	Participants		Non-participating Ratepayers	Citizens of MA at Large
	Non-Owner Participants	Customer-generator (CG)		
SREC	N/A	N/A	Negligible [1]	Negligible [1]
A	N/A	For large projects competing for PBI, Additional developer overhead due to the need to sell both winning and losing bids assumed passed along to CGs [2]	Est. EDC costs [3] + CG additional develop overhead [2]	Est. EDC costs [3] + additional developer overhead [2]
B	N/A	N/A	Est. EDC costs [3]	Est. EDC costs [3]
Notes:	[1] Ignore DOER admin costs as small; [2] estimated based on Cust. Acquisition cost data and bid/selection ratio est.; included here to capture impact since not modeled as higher installed cost under Path A. [3] estimate based on data from EDCs			

D.5 Category III: Behind-the-Meter Production within the Billing Month

The third major category of costs and benefits considered in this analysis are associated with the cost of grid-tied solar PV systems eligible for net metering. The four subcategories of costs and benefits contained within the category of behind-the-meter production include:

Generation Value of On-site Generation	CB3.1	Quantitative
Transmission Value of On-site Generation	CB3.2	Quantitative
Distribution Value of On-site Generation	CB3.3	Quantitative
Other Retail Bill Components (Transition, EE, RE)	CB3.4	Quantitative

In general, the value of these costs and benefits will vary somewhat across policy futures, given that the treatment of behind-the-meter production in each policy future can vary due to changing installation mix and volumes.

The table below illustrates how these subcategories accrue as direct costs or benefits to the four perspectives analyzed.

Table 47: BTM Production within the Billing Month Applicability to Analysis Perspectives

Perspective	Subcategories Accruing as Net Benefits to Some or All With Perspective	Subcategories Accruing as Net Costs to Some or All With Perspective
Non-Owner Participants ***(NOP)***	• Generation Value of On-Site Generation • Transmission Value of On-Site Generation • “Adjusted” Distribution Value of On-Site Generation • Other Retail Bill Components (Trans., RE, EE)	• N/A
Customer-Generators ***(CG)***	• Generation Value of On-Site Generation • Transmission Value of On-Site Generation • “Adjusted” Distribution Value of On-Site Generation • Other Retail Bill Components (Trans., RE, EE) [1]	• N/A
Non-Participating Ratepayers ***(NPR)***	• Generation Value of On-Site Generation	• Transmission Value of On-Site Generation • “Adjusted” Distribution Value of On-Site Generation • Other Retail Bill Components (Trans., RE, EE)
Citizens of the Commonwealth at Large ***(CC@L)***	• Generation Value of On-Site Generation • Other Retail Bill Components (Trans., RE, EE)	• N/A
[1] SREC Policy & Policy Path B Only		

D.5.1 Generation Value of On-Site Generation

The generation value of on-site generation is the avoided cost value of generation service obviated by the reduction in total customer load (and thus retail purchases) caused by the on-site solar PV generation. The portion of on-site solar PV generation that is consumed simultaneously by the host customer reduces a customer’s load, thus avoiding retail kilowatt-hour purchases of energy at a 1-to-1 rate. Thus, a portion of the cost avoided is the cost of generation service that the customer would otherwise receive in the absence of a solar PV system. This value is represented by the generation or “G” component of a customer’s bill, remains consistent through all three policy futures, and offsets purchases in that month only. For ease of calculation, the study utilizes the Basic Service generation rate offered by each EDC.

Table 48: Generation Value of On-site Generation Impacts by Perspective

Policy	Participants		Non-participating Ratepayers	Citizens of MA at Large
	Non-Owner Participants	Customer-generator (CG)		
All	**HO: n/a** **3PO: PPA discount on G**	**HO: Retail billing unit savings** **3PO: Retail billing unit savings less ‘discount’ to host**	**Avoided energy losses [2]**	**Sum of benefits [1]**
Notes:	[1] Sum of Participants benefits should be reduced by dollars that would have been spent on in-state renewable generation (if not for solar). Assume w/o solar carve-out the marginal RPS demand would be met with out-of-state wind, then reduction → is zero. [2] using production wtd energy loss factor			

D.5.2 Transmission Value of On-Site Generation

The transmission value of on-site generation is the value of the transmission service obviated by the reduction in total customer load (and thus retail purchases) caused by the on-site solar PV generation. Similar to generation service, the portion of on-site solar PV generation that is consumed simultaneously by the host customer reduces a customer's load, thus avoiding retail kilowatt-hour purchases of energy at a 1-to-1 rate. Thus, a portion of the cost avoided is the cost of generation service that the customer would otherwise receive in the absence of a solar PV system. This value is avoided equally across all policy futures examined, is represented by the transmission or "T" component of a customer's bill by applicable EDC, and offsets purchases in that month only.

Table 49: Transmission Value of On-site Generation Impacts by Perspective

Policy	Participants		Non-participating Ratepayers	Citizens of MA at Large
	Non-Owner Participants	Customer-generator (CG)		
SREC, A & B	**HO: n/a** **3PO: PPA discount on T**	**HO: Retail billing unit savings** **3PO: Retail billing unit savings less 'discount' to host**	**Portion of T shifted to other MA ratepayers**	n/a (transfer payment from non-participants to participants)
Notes:	T rates can vary by rate class, time of day, and season.			

D.5.3 "Adjusted" Distribution Value of On-Site Generation

The "adjusted" distribution value of on-site generation is the avoided cost value of the distribution service obviated by the reduction in total customer load (and thus retail purchases) caused by the on-site solar PV generation. The rates used for this calculation are the adjusted values published by the EDCs which incorporate a range of charges and credits carried or passed through the distribution rates, other than the charges explicitly addressed in Section D.5.4. While the degree of distribution service avoided by net solar generation that exceeds a customer's needs at a given time is a somewhat more complex question, the portion of on-site solar PV generation that is consumed simultaneously by the host customer reduces a customer's load, thus avoiding retail kilowatt-hour distribution service of energy at a 1-to-1 rate. Thus, a portion of the cost avoided is the cost of generation service that the customer would otherwise receive in the absence of a solar PV system. This value is avoided equally across all policy futures examined, and represented by the adjusted distribution or "D" component of a customer's bill by applicable EDC, and offsets purchases in that month only.

Table 50: "Adjusted" Distribution Value of On-site Generation Impacts by Perspective

Policy	Participants		Non-participating Ratepayers	Citizens of MA at Large
	Non-Owner Participants	Customer-generator (CG)		
SREC, A & B	**HO: n/a** **3PO: PPA discount on Adjusted D**	**HO: Retail billing unit savings** **3PO: Retail billing unit savings less 'discount' to host**	**D rate component shifted to other MA ratepayers**	n/a (transfer payment from non-participants to participants)
Notes:	"Adjusted " for miscellaneous charges. See example links in speaker notes. Distribution rates can vary by rate class, TOD & season.			

D.5.4 Other Retail Bill Components

The other retail bill components avoided by on-site generation are the avoided cost values of the other charges obviated by the reduction in total customer load (and thus retail purchases) caused by the on-site solar PV generation. As with generation, transmission and distribution service components avoided by on-site generation, the other bill components, which include transition, energy efficiency, renewable energy and others charges, are also avoided on by on-site generation.

Table 51: Other Retail Bill Components (Transition, EE, RE) Impacts by Perspective

Policy	Participants		Non-participating Ratepayers	Citizens of MA at Large
	Non-Owner Participants	Customer-generator (CG)		
SREC, A & B	**HO: n/a** **3PO: PPA Discount Other**	**HO: Retail billing unit savings** **3PO: Retail billing unit savings less 'discount' to host**	**TR & EE** [1]	**Avoided RE Charge payments** *macro-economic benefits of spending lost*
Notes:	"Adjusted " Transition for miscellaneous charges. See example links below. Transition rates can vary by rate class. [1] TR and EE total collections are fixed, so shifted to other customers. Decreased renewable energy collections are not recovered from ratepayers			

D.6 Category IV: Net Metering Credits beyond the Billing Month (Including Virtual Net Metering)

The fourth major category of costs and benefits considered in this analysis are associated with the costs associated with net metering credits beyond the billing month pertaining to PV systems eligible for net metering. The four subcategories of costs and benefits associated with net metering credits beyond the billing month costs include:

Offsetting On-site Usage	CB4.1	Quantitative
Virtual NM	CB4.2	Quantitative
Wholesale Market Sales	CB4.3	Quantitative
Virtual NM Administrative Costs	CB4.4	*Qualitative*

It is important to note that these values tend to vary with the amount and types of solar PV installed and producing, and vary materially between different policy futures. However, these specific values are assumed to be the same per megawatt-hour (MWh) across all policy futures, given that total amount of PV production across all scenarios does not vary dramatically. The table below illustrates the cost and benefit subcategories within this category accruing (on net) to each perspective.

Table 52: Net Metering Credits beyond the Billing Month (Including Virtual Net Metering) Applicability to Analysis Perspectives

Perspective	Subcategories Accruing as Benefits	Subcategories Accruing as Costs
*Non-Owner Participants **(NOP)***	• Offsetting On-Site Usage Beyond the Billing Month • Virtual NM	• N/A
*Customer-Generators **(CG)***	• Offsetting On-Site Usage Beyond the Billing Month • Virtual NM • Wholesale Market Sales	• N/A
*Non-Participating Ratepayers **(NPR)***	• N/A	• Offsetting On-Site Usage Beyond the Billing Month [1] • Virtual NM • VNM Admin Costs
*Citizens of the Commonwealth at Large **(CC@L)***	• Offsetting On-Site Usage Beyond the Billing Month • Virtual NM • Wholesale Market Sales	• VNM Admin Costs
[1] SREC Policy and Path B Only		

D.6.1 Offsetting On-Site Usage beyond the Billing Month

The on-site usage offset beyond the billing month is comprised of the net excess generation from the solar PV system, which is the share of generation from the system that exceeds the customer's load during the billing month, and is carried over to a subsequent month. For the purposes of this study, the rate treatment of net metering credits remains the same in Policy Path B as in the SREC policies baseline future, which is the sum of the per kilowatt-hour value of the generation, transmission, transition charge and the adjusted distribution component of customer bills. However, the net metering credit under Policy Path A is set at the wholesale value of electricity. These values have also been adjusted to account for line losses, as described in detail in Section 3.2.

Table 53: Offsetting On-site Usage Beyond Current Billing Month Impacts by Perspective

Policy	Participants		Non-participating Ratepayers	Citizens of MA at Large
	Non-Owner Participants	Customer-generator (CG)		
SREC & B	3PO NMC discounts to host	NMC Revenue = (i) HO = 100% NMC revenue + (ii) 3PO = NMC less 3PO discounts	[NMCs] less [W/S value [3] (solar production-wtd) for EDC]	NMC Revenue - (NMCs less W/S value for EDC) = WS rate [3]
A	3PO NMC discounts to host [2]	NMC Revenue = (i) HO =100% NMC revenue + (ii) 3PO = NMC less 3PO discounts [2]	n/a (costs and revenues net to 0) + Avoided energy losses	NMC Revenue * (1+ production-wtd energy losses)
Notes:	[1] Private Class III NMC does not include Distribution rates [2] Discount likely to be small or zero when value of NMC is just wholesale value **[3] This will be loss adjusted using production wtd energy loss factor**			

D.6.2 Virtual Net Metering

Virtual net metering credits include the allowed retail credit value of bill credits accruing to a non-owner participating customer as a result of a remote solar PV system they have entered into a contract with. Under the SREC policy and Policy Path B the value of VNM credits is set by current statute (and varies depending on whether a project is a Class I, Class II or Class III net metering facility and whether or not it is a government customer), the value of this credit in Policy Path A is reduced to the value of the wholesale value of electricity. The treatment of net metering credits for virtually net metered systems would be analogous to the treatment of customer-hosted systems.

Table 54: Virtual Net Metering Impacts by Perspective

Policy	Participants		Non-participating Ratepayers	Citizens of MA at Large
	Non-Owner Participants	Customer-generator (CG)		
SREC & B	3PO NMC discounts to NM offtaker	NMC Revenue = (i) HO= 100% NMC revenue + (ii) 3PO = NMC less 3PO discounts	[NMCs] less [W/S value [3] (solar production-wtd) for EDC]	NMC Revenue - (NMCs less W/S value for EDC) = WS rate [3]
A	3PO NMC discounts to NM offtake [2]	NMC Revenue = (i) HO =100% NMC revenue + (ii) 3PO = NMC less 3PO discounts [2]	n/a (costs and revenues net to 0) + Avoided energy losses	NMC Revenue * (1+ production-wtd energy losses)
Notes:	[1] Private Class III NMC does not include Distribution rates [2] Discount likely to be small or zero when value of NMC is wholesale generation value **[3] This will be loss adjusted using production wtd energy loss factor**			

D.6.3 Wholesale Market Sales

Wholesale market sales include the value of the sales by distributed solar PV systems in excess of on-site load which is not eligible for net metering. This production is sold into the wholesale electricity market. In terms of the three policy futures in the current analysis, these costs and benefits will play a more significant role in scenarios where net metering caps are maintained. While it is a largely negligible issue today, wholesale market sales by large distributed solar PV systems will become more relevant once statutory net metering program caps are reached, and more customer generators begin to focus on sales to the wholesale market. Thus, it is important to ensure that, depending on the point at which distributed PV deployment reaches both the private and public caps for all utilities (in policy futures and sub-scenarios where caps are maintained), the wholesale generator rate applies to the portion of supply that might constitute a wholesale market sale, even for some oversized behind-the-meter projects.

To ensure that this is done appropriately, the analysis utilizes projections of the production-weighted wholesale value of solar PV production on a cost per megawatt-hour ($/MWh basis. These projections were created using the AURORA model, which simulates economic dispatch of electricity, described in Appendix A. For ease of estimation, the same value per MWh is used across all policy futures, given that each policy future results in only moderately different solar PV capacity and energy production per year (relative to ISO New England scale).

Table 55: Wholesale Market Sales Impacts by Perspective

Policy	Participants		Non-participating Ratepayers	Citizens of MA at Large
	Non-Owner Participants	Customer-generator (CG)		
SREC, A & B	n/a	**Wholesale Market Revenue from sales to Grid**	**Avoided energy losses**	**Sum of Benefits = Wholesale Market Revenue from sales to Grid * (1+ production-wtd energy losses)**
Notes:				

D.6.4 Virtual Net Metering Administrative Costs

Virtual net metering (VNM) administrative costs are the costs incurred associated with billing, metering and other costs involved in administering a VNM program. EDC costs associated with these activities will continue to apply to varying degrees in the different policy futures studied. If a customer chooses to enter into a virtual net metering arrangement, that customer is required to designate beneficiary customer accounts, and do so using a Schedule Z form to do so. Given that these processes are not fully automated and are often done manually, the EDCs have noted that they must incur added costs to manually account for virtual net metering credits on the monthly bills of beneficiary accounts. To this end, some historical data was offered by Eversource Energy regarding their calculation of these costs during or prior to 2013, when the volume of virtual net metering was well below the current level.

After review of this data, the consulting team concluded that, while the cost component is certainly legitimate and potentially sufficient in magnitude to slightly impact the results of his analysis, that the data provided as difficult to extrapolate reasonably to future VNM scale, given that (1) billing systems may evolve to more efficiently account for VNM customers and beneficiary accounts and (2) EDCs could potentially avoid a material portion of such costs by deciding to cut a check to the VNM facility rather than allocate VNM credits. In any event, this category is acknowledged as a valid cost component that has not been quantified for this study.

Table 56: VNM Admin Costs Impacts by Perspective

Policy	Participants		Non-participating Ratepayers	Citizens of MA at Large
	Non-Owner Participants	Customer-generator (CG)		
All, to varying degrees, but more pertinent when NM not capped	N/A	N/A	*Est. EDC costs*	*Est. EDC costs*

D.7 Category V: Electric Market

The fifth major category of costs and benefits considered in this analysis are associated with the costs associated with avoided wholesale energy market costs pertaining to PV systems eligible for net metering. The five subcategories of costs and benefits contained within avoided electric market costs include:

Wholesale Market Price Impacts – Energy	CB5.1	Quantitative
Wholesale Market Price Impacts – Capacity	CB5.2	*Qualitative*
Avoided Generation Capacity Costs	CB5.3	Quantitative
Avoided Line Losses	CB5.4	Quantitative
Avoided Transmission Tariff Charges	CB5.5	Quantitative

It is important to note that these values tend to vary with the amount of solar PV installed and producing. However, these specific values are assumed to be the same per megawatt-hour (MWh) across all policy futures, with these values scaled to the actual solar PV production volumes projected in each instance. The table below illustrates the cost and benefit subcategories within this category accruing (on net) to each perspective.

Table 57: Electric Market Impacts Applicability to Analysis Perspectives

Perspective	Subcategories Accruing as Benefits to Some or All With Perspective	Subcategories Accruing as Costs to All or Some With Perspective
*Non-Owner Participants **(NOP)***	• N/A	• N/A
*Customer-Generators **(CG)***	• Avoided Generation Capacity Costs • Avoided Transmission Tariff Charges [1]	• N/A
*Non-Participating Ratepayers **(NPR)***	• Wholesale Market Impacts – Energy • Wholesale Market Impacts – Capacity [1] • Avoided Generation Capacity Costs (and Avoided Capacity Reserves) • Avoided Line Losses • Avoided Transmission Tariff Charges [1]	• N/A
*Citizens of the Commonwealth at Large **(CC@L)***	• Wholesale Market Impacts – Energy • Wholesale Market Impacts – Capacity [1] • Avoided Generation Capacity Costs (and Avoided Capacity Reserves) • Avoided Line Losses • Avoided Transmission Tariff Charges [1]	• N/A
[1] Explored qualitatively		

D.7.1 Wholesale Market Impacts – Energy

Energy-related wholesale market impacts represent the value of the difference in wholesale energy prices due to the impact of solar PV installations which create downward pressure on energy locational marginal prices in New England's bid-based market. These impacts vary between policy futures strictly as it relates to the amount and overall pace of solar PV deployment in each policy future. While energy market price impacts can result in a transfer payment from the perspective of other wholesale generators (a perspective outside of the analysis scope) this price effect can result in short-term market price effects (known in the energy efficiency world by the colorful acronym DRIPE, for demand reduction induced price effect) connected to solar deployment. To measure these effects, the study uses the quantity of PV injected into system in order to determine the change in locational spot LMPs from addition of solar, which is assumed by the analysis to have zero variable costs.

To quantify these effects, the study utilizes the annual results from AURORA dispatch modeling between the solar and no solar cases under both frameworks discussed in Section 1.3. These values were adjusted downward using the approach and assumptions used in the Avoided Energy Supply Cost 2013 study (as discussed further in Appendix A) to reflect (i) the temporary nature of the price impact, and (ii) applied only to assumed fraction of energy consumed in Massachusetts not hedged through long-term contracts (and thus impacted by changes in spot prices).

Table 58: Wholesale Market Price Impacts – Energy Impacts by Perspective

Policy	Participants		Non-participating Ratepayers	Citizens of MA at Large
	Non-Owner Participants	Customer-generator (CG)		
SREC, A & B	n/a	n/a	**Net Energy Market Price Impact [1.2]**	**Net Energy Market Price Impact [1,2]**
Notes:	[1] When solar displace wind, + or - net benefit of wind vs. PV; when displaces nat. gas, + benefit of displacing nat. gas [2] MWh Adjusted upward to reflect avoided production-weighted energy losses			

D.7.2 Wholesale Market Impacts – Capacity

Capacity-related wholesale market impacts represent the impact of injecting solar PV into the system on the regional Forward Capacity Market (FCM) price. As with energy-related wholesale market impacts vary between policy futures strictly as it relates to the amount and overall pace of solar PV deployment in each policy future.

Quantitative measurement of the Forward Capacity Market (FCM) price impacts associated with the injection of an additional quantity of PV into the system is outside of the scope of the analysis. However, in a qualitative sense, while the change in the price of capacity is less likely to be material in scenarios comparing the Solar Carve-Out to a scenario in which wind is the marginal compliance resource (and thus relatively insignificant) ignored In the event PV was incremental, the avoided cost impact, while small, may be more noticeable when compared to natural gas.

Table 59: Wholesale Market Price Impacts – Capacity Impacts by Perspective

Policy	Participants		Non-participating Ratepayers	Citizens of MA at Large
	Non-Owner Participants	Customer-generator (CG)		
SREC, A & B	n/a	n/a	*Net Capacity Market Price Impact*	*Net Capacity Market Price Impact*
Notes:				

D.7.3 Avoided Generation Capacity Costs (Including Avoided Capacity Reserves)

Avoided generation capacity and avoided capacity reserve costs are the costs foregone in the wholesale market associated with the reduced need for capacity as a result of solar PV.

One value associated with distributed solar PV is the degree to which such resources reduce the need for new generation capacity, as well as installed capacity reserves (ICR). This subcategory of costs and benefits addresses (1) components of peak reduction impact, (2) the commensurate reduction in required ICR, and (3) the value of the share of overall solar capacity monetized in the FCM market.

Under net metering tariffs, EDCs control rights to FCM from net metered systems, although to date they have thus far elected not to participate with this FCM in the Forward Capacity Auctions due to risk allocation and a lack of control. Whether they do or not, the claimed capability value of solar will reduce the ICR, thus will accrue to load, once PV is incorporated in ICR forecast as proposed for future FCAs.

In addition, the analysis described in Section 3.1 revealed that solar PV's electric load carrying capacity (ELCC), which decreases as PV penetration increases and shifts peak hours later into the evening, is substantially higher than the Seasonal Claimed Capacity for intermittent renewables in FCM – the value of which is independent of penetration. As Figure 4 in Section 3.1 shows, solar reduces peak, and thus the ICR, to the extent the peak reduction benefit is not fully captured in solar SCC calculations. The analysis in Section 3.1 also calculates the impact on peak reduction from solar PV as a function of penetration, which is used in these calculations. Thus, this analysis derives both the capacity impacts of distributed solar PV, and the installed capacity reserves (ICR), the net of which is the value of avoided capacity reserve requirements and on-peak line losses (also discussed in Section 3.2 and Section D.7.4).

Table 60: Avoided Generation Capacity Costs (Including Avoided Generation Capacity Reserve Costs) Impacts by Perspective

Policy	Participants		Non-participating Ratepayers	Citizens of MA at Large
	Non-Owner Participants	Customer-generator (CG)		
SREC, A & B	n/a	**For 28.8% of market directly participating as supply, FCM revenue [1]**	**Full value of ELCC less amount monetized by CGs may accrue to all ratepayers. (For solar not directly participating in FCM: (i) market value of avoided ICR reduction [2], PLUS (ii) difference between ELCC value (in reducing system ICR) and value as calculated for SCC [3])**	**ELCC* Value of Capacity [3]**
Notes:	[1, 2] Annual MW_{DC} Solar * 1000 kW/MW * FCM price forecast ($/kW-mo) * 12 months * (SCC * 4 mos. + WCC * 8 mos.)* % participating in market; WCC = 0; 28.8% from NESCOE presentation to NEPOOL Reliability Committee: *Accurate ICR Calculation Approach, 11/19/14* → citing [56 MW of DR PV with CSOs + 85 MW of PV with included on the load side for the FCA9 ICR calculation] divided by 489 MW total forecast = 28.8% [3] Annual MW_{DC} Solar * 1000 kW/MW * ELCC Peak reduction % * FCM price forecast ($/kW-mo) * 12 months * (1+reserve%) * (1+peak loss factor).			

D.7.4 Avoided Line Losses

Line losses represent the generated energy that is lost due to electrical resistance in the process of delivering (i.e. transmitting and distributing) electricity from source to sink. The derivation of loss factors in discussed in Section 3.2. The applicable loss factors are applied to individual cost and benefit components throughout this study, rather than being tallied explicitly as an individual line item. The value of avoided *marginal* losses due to locating generation on the periphery of the distribution system near load is not captured by prices for generation, but accrues broadly to load, and thus to all ratepayers. Thus, the study adjusts many of the costs and benefit subcategories within this analysis using a solar production-weighted line loss formula based on statewide average line loss figures outlined in Table 9 in Section 3.2.

D.7.5 Avoided Transmission Tariff Charges

Avoided transmission tariff charges represent the ISO New England Regional Network Service (RNS) cost reductions caused by coincident solar peak load reduction. While solar PV deployment does not reduce the ISO's total transmission revenue requirement, through the reduction in billing units costs are shifted to other states (in concert with increased per-kW rates). Through this mechanism, Massachusetts distributed solar PV installations can shift 1 minus the state's load ration share. In the absence of installing distributed generation in state, similar policies implemented in other states would have the effect of shifting load to Massachusetts, so this can be thought of as defensive in nature.

Table 61: Avoided Transmission Tariff Charges Impacts by Perspective

Policy	Participants		Non-participating Ratepayers	Citizens of MA at Large
	Non-Owner Participants	Customer-generator (CG)		
SREC, A & B	n/a	*On-site load: % of RNS avoided * on-site load not displaced by PV [1]* *NM Credits: Reduction to NMC value due to lower TX rates [1]*	**RNS Charges avoided (shifted) for all load [2]**	**RNS Charges avoided (shifted) for all load [2]**
Notes:	[1] very small, ignore [2] Each year $ value = **[RNS rate ($/kw-yr*1000kW/MW) * [(case-specific RNS% reduction per MW_{DC}) * (case-specific Avg MD(DC) during year)*(1+peak T&D losses)]*(1-MA LRS)**			

D.8 Category VI: Electric Investment Impacts

The sixth major category of costs and benefits considered in this analysis are associated with the costs associated with avoided electric infrastructure investment costs pertaining to PV systems eligible for net metering. The four subcategories of costs and benefits contained within avoided electric investment costs include:

Avoided Transmission Investment - Remote Wind	CB6.1	Quantitative
Avoided Transmission Investment – Local	CB6.2	Quantitative
Avoided Distribution Investment	CB6.3	Quantitative
Avoided Natural Gas Pipeline	CB6.4	*Qualitative*

It is important to note that these values tend to vary with the amount of solar PV installed and producing. The table below illustrates the cost and benefit subcategories within this category accruing (on net) to each perspective.

Table 62: Electric Investment Impacts Applicability to Analysis Perspectives

Perspective	Subcategories Accruing as Benefits to Some or All With Perspective	Subcategories Accruing as Costs to All or Some With Perspective
Non-Owner Participants ***(NOP)***	• N/A	• N/A
Customer-Generators ***(CG)***	• N/A	• N/A
Non-Participating Ratepayers ***(NPR)***	• Avoided Transmission Investment – Remote Wind • Avoided Transmission Investment – Local • Avoided Distribution Investment • Avoided Natural Gas Pipeline Investment [1]	• N/A
Citizens of the Commonwealth at Large ***(CC@L)***	• Avoided Transmission Investment – Remote Wind • Avoided Transmission Investment – Local • Avoided Distribution Investment • Avoided Natural Gas Pipeline Investment [1]	• N/A
[1] Explored qualitatively		

D.8.1 Avoided Transmission Investment – Remote Wind

Avoided transmission investment associated with remote wind installations represents the cost of transmission infrastructure connecting remote wind installations to load centers avoided by solar PV. Given the assumption in this study that RPS compliance in the absence of the Solar Carve-Out would comprise Class I land-based wind RECs, installations of PV in Massachusetts under the Carve-Out can displace cost that would otherwise be incurred to build additional transmission to access wind sited out-of-state. The impact to Massachusetts ratepayers can be represented by the avoided proportion of the cost of transmission not borne by wind generators captured in Class I REC prices, but instead allocated to network load customers (through the ISO-NE RNS tariff). This value can be stated as the net present value of:

$$Total\ \$/MWh\ Avoided$$
$$= (Avoided\ Transmission\ \$/MWh\ \ Allocated\ to\ Load * MA\ Load\ Ration\ Share\ for\ ISO - NE\ Tariff)$$
$$* MA\ T\&D\ Loss\ Adjustment$$

Where: $MA\ T\&D\ Loss\ Adjustment = 1 + (\%\ of\ MA\ Average\ PV\ Production\ Weighted\ Losses)$

There is a great deal of uncertainty in the ultimate cost of this transmission in total and per-unit (depending on whether transmission is loaded lightly at wind capacity factors or more heavily with a wind/hydro blend), as well as the degree to which such costs would be allocated to network transmission customers. As a result, this value is estimated parametrically. The base assumption was developed by SEA for other projects as a middle-of-the-range value, as described further in Appendix A in the discussion of parametric values assumptions.

Table 63: Avoided Transmission Investment - Remote Wind Impacts by Perspective

Policy	Participants		Non-participating Ratepayers	Citizens of MA at Large
	Non-Owner Participants	Customer-generator (CG)		
SREC, A & B	n/a	[1]	Avoided Share of network TX costs allocated to load	Avoided Share of network TX costs allocated to load
Notes:	[1] Since T rates would go down (relative to no solar policy), there would be some lost NMC benefit, but this is second-order and ignored			

D.8.2 Avoided Transmission Investment – Local

Avoided local transmission investment comprises the costs avoided by solar PV inasmuch as it allows an EDC to defer *(or* defer to the point *of* avoiding) investments intended to upgrade local transmission or sub-transmission systems.

When solar PV is installed near load, some of it will contribute to changes in EDC planning, such that some local transmission upgrade investments will be *deferred*, potentially for many years (in some cases equivalent to *avoiding* the investment), that otherwise would have been needed to provide additional capacity to meet peak growth. This deferral value is, in fact, location-specific, but can be estimated on average over EDC service territory.

The estimates of **capital costs** and deferral benefits associated with solar PV contained in this analysis are taken from literature review, and adjusted to be comparable by applying MA- and PV-specific factors discussed in Section 3.1. The active benefits derived from this literature review are site-specific, and all deferral benefits are a function of growth, and technical means may be required to achieve the deferral effect in local transmission planning. Extrapolating net present value of the benefit from site-specific deferral values across a EDC territory can be stated as:

$$NPV_{EDC\ Territory}$$
$$= (Avoided\ Transmission * \%\ of\ Transmission\ Areas\ with\ Load\ Growth * \%\ of\ PV\ Dependable\ Capacity)$$

In this case, "dependable capacity" includes the use of physical assurance, storage, smart inverters with ride-through, linked DR and/or other means of ensuring the capacity benefits of PV. These benefits have been adjusted upward to reflect the impact of avoided peak demand line losses, as described in Section 3.2, and are assumed to be the same across all policy futures. The resulting values use the case-specific peak impact values calculated in Section 3.1 for each year.

Table 64: Avoided Transmission Investment – Local Impacts by Perspective

Policy	Participants		Non-participating Ratepayers	Citizens of MA at Large
	Non-Owner Participants	Customer-generator (CG)		
SREC, A, B	n/a	n/a	Costs deferred or avoided [1]	Costs deferred or avoided [1]
Notes:	[1] This benefit/kWh each year = (Revenue requirements for average **local transmission** upgrade capital cost ($/kW-yr) * Deferral savings as X% of upgrade cost * Solar ELCC/DCP as Y% of solar kW) / penetration of all distributed kW as Z**%** of upgrade kW			

D.8.3 Avoided Distribution Investment

Avoided distribution investment is the total cost that solar PV allows an EDC to defer *(or* defer to the point *of* avoiding) investments intended to upgrade local primary and secondary distribution systems. When solar PV installed near load, some of it will contribute to changes in EDC planning, such that some upgrade investments will be deferred, potentially for many years (in some cases equivalent to *avoiding* the investment), that otherwise would have been needed to provide additional capacity to meet peak growth. This deferral or effective avoidance can either be active or passive in nature.

For Active Distribution Deferral, the Avoided Distribution Investment methodology for this study had five main steps:

- First, estimates of deferral benefits were taken from a literature review. Seven sources were selected to represent a reasonable range of conditions and methodologies, and an average value was calculated from these sources for the area-wide passive deferral benefit of solar PV, as described more fully in Appendix E.[24] These sources included three case studies of active deferral in particular New England locations and four reports with estimates of passive or area-wide deferral impacts and with adequate detail on their methodologies. Where necessary, the estimates from four of these sources were adjusted to be comparable by applying MA-specific and PV-specific factors.
- Second, to confirm the reasonableness of the average distribution deferral value from the literature, that value was compared against a simplified analysis driven by assumptions about distribution feeder load growth, upgrade costs, solar penetration and coincidence of solar output with feeder load.
- Third, the analysis assumes that the percentage of the state's distribution system to which estimates of "active deferral" are applicable; this is the portion of the system that is growing and so will require new capacity or otherwise provides

[24] These sources are listed in Appendix E, along with their URLs. Some of them were also referenced in "Review Of Solar PV Benefit & Cost Studies," 2nd Edition, Rocky Mountain Institute, September 2013 (www.rmi.org/elab_emPower), pages 31-34.

opportunities to defer distribution investments, estimated to be 30%.[25] This was applied to estimates from the literature review to the simplified analysis in Step 2 to get statewide values.[26]

Thus, the total active deferral benefits of a 100% peak coincident resource are the net present value of:

$$NPV_{EDC}(Active\ Dist. Deferral) = \frac{Distribution\ Deferral\ Value\ (\$/MWh)}{(Total\ PV\ MWac\ Causing\ Deferral) * Production\ Hours}$$

where

$$PV\ Causing\ Deferral = \left(\frac{Solar\ PV\ Capacity\ Causing\ Deferral}{ELCC\ (or\ Distribution\ Congestion\ Price, if\ Available)}\right)$$

However, if distributed solar PV is installed without integration into planning, the net deferral or avoidance benefits accrue in a rather different manner. While current utility planning assumes limited to no distribution deferral or avoidance benefit associated with PV in the short run, it can be assumed that over time, localized distribution planning (or the existence of distribution congestion pricing, if applicable) will take the solar into account in advance, leading to a “passive” deferral value that may be quantifiable in the future. While the passive value cannot currently be calculated on a locational basis without similar location-specific deferral values at many smaller, distribution-level nodes (often known as “buses”) the analysis calculates the total deferral value (including an estimate of passive deferral value) that can currently be averaged across each EDC service territory.

- Thus, the fourth and penultimate step is to account for a number of factors that may be required in order for distribution planners to sufficiently rely upon solar DG to actually achieve a deferral of upgrade investments. To do this, the analysis results include a factor of 50% for the percentage of PV that can be counted upon for distribution deferral through the use of physical assurance, storage, smart inverters with ride-through, linked demand response and/or other means.
- The final step is to account for the estimated PV contribution at times of local system peak (the Est % of Dependable PV Capacity from the formula below).

Total Distribution Deferral Value: Thus, the formula for calculating the benefits of both active and passive deferral, as derived from a literature review of Massachusetts- and PV-specific values from is the net present value of:

$$NPV_{EDC}\ (Total\ Dist. Deferral) = \frac{\left(\begin{matrix}((Modeled\ Deferral\ Value\ \ \$/MWh * 50\%) + (LitReview\ Deferral\ Value * 50\%\ )) * \\ Est\ \%\ of\ System\ with\ Load\ Growth * Est\ \%\ of\ Dependable\ PV\ Capacity\end{matrix}\right)}{(1 - \%\ Average\ MA\ Line\ Losses)}$$

[25] For portions of the distribution system on which there is literally no load growth, there is essentially no deferral opportunity for DER. However, the deferral benefit is at its highest with load growth around ½ of 1 percent/year, other things being equal, since DER (at an assumed 10% penetration) can not only defer the upgrade but avoid it for an entire 30-year period.

[26] The average values used in this report will not be representative of any particular location.

where

$$\% \; of \; System \; with \; Load \; Growth = 30\%$$

and

$$Est. \% \; of \; Dependable \; PV \; Capacity = 50\%$$

Table 65: Avoided Distribution Investment Impacts by Perspective

Policy	Participants		Non-participating Ratepayers	Citizens of MA at Large
	Non-Owner Participants	Customer-generator (CG)		
SREC, A, B	n/a	n/a	**Costs deferred or avoided**	**Costs deferred or avoided**
Notes:	Assume integration costs are internalized in charges to PV generators			

D.8.4 Avoided Natural Gas Pipeline

Avoided natural gas pipeline costs include the costs associated with building natural gas pipeline infrastructure to serve natural gas-fired generation that may be avoided by solar PV resulting from the deferral or avoidance of a new gas-fired generating unit.

When new natural gas-fired power plants are built or add to their capacity, added pipeline capacity to serve those plants may be needed (and under current pipeline-constrained conditions in New England, this can be assumed to be the case). While solar has a lower capacity value during winter peak electricity (which coincides roughly with peak annual gas demand), increased PV capacity can potentially reduce total investment in gas pipeline capacity. These effects could be accentuated as technologies evolve to optimize PV's dependable capacity.

However, in part because capacity that leverages the Solar Carve-Out is generally assumed to replace wind, these benefits are outside the scope of the analysis, and are largely speculative at this juncture. While they are not quantified in this analysis, the associated avoided cost value related to PV would apply in the future if the cost of building future pipeline capacity is built into electricity prices and the amount of pipeline capacity needed reflected the (modest winter) contribution of solar to reducing winter energy demand.

Table 66: Avoided Natural Gas Pipeline Impacts by Perspective

Policy	Participants		Non-participating Ratepayers	Citizens of MA at Large
	Non-Owner Participants	Customer-generator (CG)		
SREC, A & B	n/a	n/a	*Reduced cost of NG Pipeline in ISO Tariff*	*Reduced cost of NG Pipeline in ISO Tariff*
Notes:				

D.9 Category VII: Externalities and Other

The final major category of costs and benefits considered in this analysis are associated with the costs associated with avoided external costs and other costs to society pertaining to PV systems eligible for net metering. The five subcategories of costs and benefits contained within externalities and other costs include:

Avoided Environmental Costs CO_2, NO_x and SO_x	CB7.1	Quantitative
Avoided Fuel Uncertainty	CB7.2	*Qualitative*
Resiliency	CB7.3	*Qualitative*
Impact on Jobs	CB7.4	*Qualitative*
Policy Transition Frictional Costs	CB7.5	*Qualitative*

It is important to note that these values tend to vary with the amount of solar PV installed and producing. The table below illustrates the cost and benefit subcategories within this category accruing (on net) to each perspective.

Table 67: Externalities and Other Impacts Applicability to Analysis Perspectives

Perspective	Subcategories Accruing as Benefits	Subcategories Accruing as Costs
Non-Owner Participants ***(NOP)***	• N/A	• Policy Transition Frictional Costs [1]
Customer-Generators ***(CG)***	• Avoided Fuel Uncertainty [1]	• Policy Transition Frictional Costs [1]
Non-Participating Ratepayers ***(NPR)***	• Avoided Environmental Impacts	• Policy Transition Frictional Costs [1]
Citizens of the Commonwealth at Large ***(CC@L)***	• Avoided Environmental Impacts • Avoided Fuel Uncertainty [1] [3] • Resiliency [1] [3] • Impact on Jobs [1] [3]	• Policy Transition Frictional Costs [1] • Impact on Jobs [1] [2] • Resiliency [1] [2]
[1] Explored qualitatively [2] (Qualitative) potential cost component [3] (Qualitative) potential benefit component		

D.9.1 Avoided Environmental Costs (CO_2, SO_x and NO_x)

Avoided environmental costs include the costs (both priced and not priced) of environmental damage associated with the emission of carbon dioxide (CO_2), sulfur dioxide (SO_x) and nitrogen oxides (NO_x) electricity generation utilizing fossil fuels.

To account for these avoided external environmental costs, the analysis, which includes analysis of scenarios assuming both full (and partial) compliance with Class I RECs assumes that each ton of CO_2, NO_x & SO_x abated by solar PV production avoids the equivalent net social cost of emitting each ton of these pollutants. The net social cost per ton avoided is represented by the difference between the societal value of the environmental damage and the already internalized market price of the emissions avoided by PV production. The quantities of avoided emissions were modeled through the AURORA dispatch analysis, which can account for added or avoided natural gas generation. The derivation of the societal value of avoided emissions uses standard methodologies used by US EPA, and are discussed further in Appendix A.

Table 68: Avoided Environmental Costs CO_2, NO_x and SO_x Impacts by Perspective

Policy	Participants		Non-participating Ratepayers	Citizens of MA at Large
	Non-Owner Participants	Customer-generator (CG)		
SREC, A, B	n/a	n/a	**Net impact (+ or -) of shift between solar and wind (or natural gas) [1,2]**	**Net impact (+ or -) of shift between solar and wind (or natural gas) [1,2]**
Notes:	[1] Avoided cost each year = net change (tons/yr) * [societal cost – market price ($/ton)] **[2] This will be loss adjusted using production wtd energy loss factor**			

D.9.2 Avoided Fuel Uncertainty

Avoided fuel uncertainty accounts for the costs associated with the risk of a significant change in the price of fuels for electricity generation (specifically natural gas) and the associated costs of fuel hedging contracts and other instruments that can be avoided by solar PV deployment. In the case of solar PV, the value of avoided fuel cost uncertainty would capture the value of price-certain resource compared to a price-uncertain resource. While quantitative analysis of this value is beyond the scope of this study, the factor was recently included in Maine's Value of Solar Study (Clean Power Research, LLC; Sustainable Energy Advantage, LLC; Perez Richard; Pace Law School Energy and Climate Center, 2015) released in March 2015. The Maine VOSS quantified this value to be $0.037/kWh (on a 25-year levelized basis) at by estimating the cost associated with eliminating long term price uncertainty with procuring the quantity of natural gas displaced by solar PV. To do this, the authors of that analysis calculated the difference between the non-guaranteed and guaranteed price of natural gas to determine the net present value of hedging natural gas purchases. Thus, it appears that this methodology could be utilized in Massachusetts and could represent a significant value in Massachusetts. We have not, however, included this value within this analysis.

Table 69: Avoided Fuel Price Uncertainty Impacts by Perspective

Policy	Participants		Non-participating Ratepayers	Citizens of MA at Large
	Non-Owner Participants	Customer-generator (CG)		
SREC	*3PO: all, assuming (to simplify) that 100% of deals are at a fixed price or fixed discoint with floor* [1]	*HO: all consumed on site or rolled forward or net metered No value for any generation sold at W/S, which includes generation not consumed on-site post NM caps*	**n/a**	*Sum of participants*
A, B	*Complex?*	*Complex?*	*value for any generation sold at W/S, which includes generation not consumed on-site post NM caps*	*Value * all production?*
Notes:	[1] simplified representation, ignores % discount deals which would lose this benefit			

D.9.3 Resiliency

Resiliency describes the broad category of benefits solar could provide, if accompanied by storage, as a beneficial ancillary service to the utility grid. Sector A in the current SREC-II program Sector A includes "Emergency Power Generation Units", but the benefits of these units (and their broader deployment during an emergency situation) is not yet readily quantifiable. The ability to provide emergency ancillary services benefits, however, could provide significant situational value, and is thus discussed qualitatively in greater depth in Section 9.2. However, the net benefits will depend on the level of increased costs needed to create resiliency benefits.

Table 70: Resiliancy Impacts by Perspective

Policy	Participants		Non-participating Ratepayers	Citizens of MA at Large
	Non-Owner Participants	Customer-generator (CG)		
SREC, A, B	n/a	*Additional Cost for resiliency features Host receives resiliency benefits*	n/a	*Resiliency benefits less costs*
Notes:				

D.9.4 Impact on Jobs

Job impacts associated with solar PV include the jobs gained and lost as a result of an increased (or decreased) rate of solar PV deployment. The deployment of solar PV affects overall employment in Massachusetts in three distinct ways: 1) through the in-state proportion of added jobs driven by solar installations and related supply chain (including, where applicable, manufacturing), 2) the potential loss of jobs in the wind sector associated with greater solar capacity (but which largely occurs out of state), and 3) the impact on employment from increased ratepayer costs resulting from any premium paid by those citizens, which is impacted by the share of revenue that would be spent in Massachusetts. While quantitative analysis of this issue is beyond the scope of this study, the impact on jobs is likely to differ between policies, and is explored in Section 9.1.

D.9.5 Cost-Benefit Impacts by Perspective

Table 71: Impact on Jobs Impacts by Perspective

Policy	Participants		Non-participating Ratepayers	Citizens of MA at Large
	Non-Owner Participants	Customer-generator (CG)		
SREC, A, B	n/a	n/a	n/a	*Direct solar and related jobs added* *Job losses due to redirected spending of solar premiums* *Indirect Macroeconomic impacts*
Notes:	Beyond scope; Potential area for further study			

D.9.6 Policy Transition Frictional Costs

The "frictional" costs associated with a broad-scale policy transition refer to the potentially significant (but difficult to quantify) costs to solar market stakeholders and other participants associated with broad-scale solar policy change. The issue of the *ex post* costs to current market participants associated with policy friction was raised by stakeholders in interviews and at meetings of the Task Force. Indeed, these conversations have revealed the fears of customer-generators, investors, market-makers, and other market participants of the "substantial" costs cited as potential impact of transition to these parties from one policy regime to another. In fact, several stakeholders in Group F suggested this could be reflected as an increased cost of financing and departure of investors from markets, as well as layoffs if the market pauses as a result of policy uncertainty. Specifically, one investor in this group suggested that impact could be modeled as a 300-400 basis point increase in cost of capital (in some cases), while a lender indicated that investors tend to discount revenues that are more uncertain, thus increasing the cost of financing.

One approach to mitigate this uncertainty suggested by certain members of the Task Force could be to design in longer lead times prior to change in the policy regime in order to allow time to adapt), particularly with respect to existing deals in the project and financing pipeline.

It is foreseeable that an entirely separate set of *ex post* costs and benefits will accrue as a result of policy friction, and may ultimately be substantial. However, it is exceedingly difficult to account for the uncertain *ex post* nature of these impacts unique to the policy future selected (or variation thereof) in the absence of reliable comparisons on an *ex ante* basis. As such, while it is important for these costs to be considered further (and potentially quantified as part of any further analysis), quantitative analysis of the costs and benefits associated with friction is not a component of this analysis.

Table 72: Policy Transition Frictional Costs Impacts by Perspective

Policy	Participants		Non-participating Ratepayers	Citizens of MA at Large
	Non-Owner Participants	Customer-generator (CG)		
Any transition could trigger...	*Loss of savings capture due to increased costs*	*Increased costs due to increase in uncertainty*	*Higher compliance costs*	*Job losses*
Notes:				