Task 3: Evaluating the Costs and Benefits of Alternative Net Metering and Solar Policy Options in Massachusetts

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Executive Summary

Objectives

Section 7(b) of Chapter 251 of the Acts of 2015 directs the Massachusetts Net Metering and Solar Task Force to "assess and report to the legislature on the costs and benefits of the existing net metering framework from the perspectives of the customer-generator, non-participating ratepayers and the citizens of the commonwealth at large." Task 3 of the Task Force scope of work further directs the consultants to compare the cost and benefits of current Massachusetts net metering and solar incentive policy to other policies from those different stakeholder perspectives. This report serves to:

- Evaluate the costs and benefits of the current solar and net metering incentive landscape;
- Compare the current policy landscape with alternative future policy 'paths' and inform the Task Force and policy makers regarding the impact of changes to net metering and solar policy in Massachusetts; and
- Calculate and present the costs and benefits of each future policy path from specified stakeholder perspectives, through the current level of policy targets (1600 MW_{DC} of solar photovoltaic (PV) capacity in Massachusetts) and beyond.

Study Components and Methodology

In order to determine the costs and benefits associated with alternatives to Massachusetts' current solar policies, the Net Metering and Solar Task Force seeks to evaluate the costs and benefits of those alternatives relative to a baseline policy future. To do this, this study examines both 1) the impacts of existing systems and 2) the forecasted impacts of future systems under three policy futures:

- **"SREC Policy"** – Policy in this scenario would remain the same as under current law and policy, save for the sub-scenarios in which the baseline is extended to include a third Solar Carve-Out program (SREC-III). Incentives would remain market-based, tradable SRECs modulated by existing (and, for SREC-III, forecasted) Solar Alternative Compliance Payment (SACP) and Solar Credit Clearinghouse Auction (SCCA) trajectories that serves as a price ceiling and soft floor.
- **Policy Path A** – Under Policy Path A, the SREC programs are replaced by a set of declining-block and performance-based incentives that decline over time for small projects (≤ 25 kW dc), and through competitive bidding for the large projects (> 25 kW dc). Additionally, net metering credits, where available, are limited strictly to the generation component of customer rates.
- **Policy Path B** – Under Policy Path B, the SREC market structure is replaced by 1) an incentive that reflects an upfront payment based on the expected lifetime performance of the PV system (similar to programs in New York and California) for small projects and 2) a similar declining-block incentive to that proposed in Policy Path A for large projects. Net metering credits in this scenario would reflect the full generation, transmission and distribution values customers currently receive.

The study also breaks out these policy futures into sub-scenarios for further analysis based on:

- Whether the MW target is expanded to 2500 MW (or remains at 1600 MW);
- Whether the aggregate net metering caps under current law remain in place or are removed.

Given these policy futures and associated sub-scenarios, the analysis calculates the market impacts associated with each, including ~~the total megawatts (MW) installed by type of installation, the total impact to SREC prices under the existing (and h~~ypothetical)

Carve-Out programs, the total solar incentives as part of Policy Paths A&B, all for both 1) when net metering caps are reached and 2) when total MW targets under each sub-scenario are reached.

The study also breaks the total costs and benefits associated with each of these policy futures and sub-scenarios into the following categories: PV System Costs; Solar Policy; Behind-the-Meter Production in the Billing Month; Net Metering Credits Beyond the Billing Month; Electric Market; Electric Investment Impacts; and Externalities and Other impacts.

Finally, per the legislation creating the Task Force, each component of the costs and benefits associated with solar PV was considered for each of four key perspectives:

- **Non-owner participants** that benefit from (but do not own) solar PV systems;
- **Solar customer-generators** that own and/or operate solar PV systems;
- **Non-participating ratepayers** that do not directly participate in solar PV programs; and
- **The citizens of Massachusetts at large,** the aggregate impacts accruing to in-state entities.

Key Takeaways and Observations

Overall

- Under all scenarios, Massachusetts reaches its current goal of 1600 MW of PV by 2019.
- Under all scenarios, the benefits of the solar program exceed the costs by more than 2 to 1. The benefit:cost ratios for the citizens of Massachusetts at large range from 2.2:1 to 2.7:1.
- All future scenarios examined would be less expensive than the current SREC-I and SREC-II program.
- The choice of policy path affects both the costs and benefits and the type of systems that will be built. Paths that include net metering caps will result in a higher percentage of smaller, onsite systems; paths without net metering caps will result in a higher percentage of larger systems.

SREC Policy Baseline

Market Impacts: Under the SREC scenarios analyzed in this study, the SREC-II goal of 1600 MW by 2020 could be reached as early as 2018, while a hypothetical SREC-III goal of 2500 by 2025 could be met as early as 2020 or 2022, depending on whether net metering caps are removed. In addition, in part due to the declining cost of solar PV, the total cost of the Carve-Out relative to total solar deployment is expected to decline with each successive Carve-Out program, and the cost of a hypothetical SREC-III program is no exception. In the SREC-driven scenarios in which net metering caps are kept in place, small installations are expected to dominate the market. However, the rapid growth enabled by the SREC programs and virtual net metering could lead to a more volatile Massachusetts solar market toward end of the decade, as net metering caps and step-downs of the federal investment tax credit built into existing law are reached.

Costs and Benefits: While the SREC programs are expected to come at a net cost to non-participating ratepayers of **$2.7-$2.9 billion** over 25 years, these programs are also expected to provide **$7.0-$8.8 billion** in net benefits to the citizens of Massachusetts over the same period, depending on the scenario analyzed. Customer-generators and non-owner participants are likely to enjoy a net benefit ranging from **$2.2-$3.8 billion** and **$734-$809 million**, respectively.

Policy Path A

Market Impacts: In all Policy Path A scenarios, larger installations tend to be built out, especially those currently classified as "Managed Growth" installations. This is a shift from the SREC Policy net metering cap future which has no Managed Growth

installations built after SREC-II is complete and is dominated by under 25 kW projects. The status of net metering caps under Policy Path A is crucial to project mix. When net metering is uncapped and available virtually net metered PV installations would have significant cost advantages and therefore dominate the mix of projects built. Regardless of net metering status, relative to the SREC Policy scenario, under Policy Path A the market reaches a more stable equilibrium at a lower growth level through 2025.

Costs and Benefits: Depending on the scenario, Policy Path A is expected to reach the 2500 MW goal by 2025 at a reduced net cost to non-participating ratepayers and reduced net benefit to citizens of Massachusetts at large relative to the SREC Policy pathway. Customer-generators and non-owner participants also realize a reduced net benefit relative to the SREC Policy pathway. Further, if net metering is not capped, the total net cost to ratepayers is lower than if caps remain in place. The specific net benefit values of Policy Path A relative to the SREC policy baseline are explored below.

Policy Path B

Market Impacts: In broad terms, Policy Path A and B are relatively similar in terms of the installations incented to be built. While installations under 25kW will remain relatively constant between Policy Path A and B, they remain significantly lower than in the SREC Policy future, despite the fact that these installations will also reach grid parity by the early 2020s. In addition, the degree to which Community Shared Solar and virtually net metered low income housing (VNM LIH) installations are enabled by the program is dependent upon the availability of net metering. Policy Path A and B are also similar in that each creates a more stable market at a lower rate of growth than the SREC Policy future, but Policy Path B is somewhat more volatile, given that it is a market-based program.

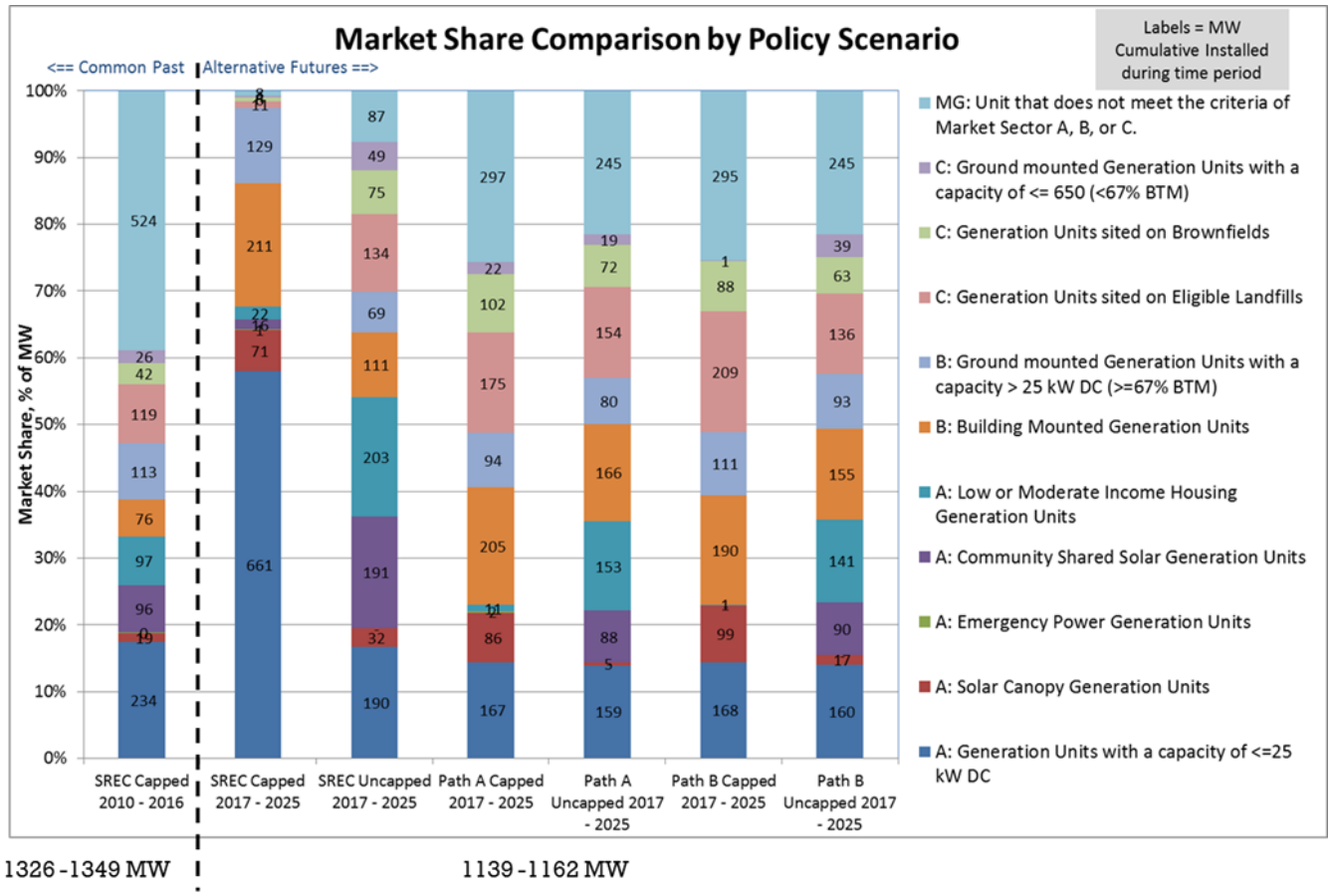
Costs and Benefits: The 25-year net costs to non-participating ratepayers and net benefits to Massachusetts citizens at large associated with Path B are elevated somewhat relative to Path A, but are both lower on net relative to the SREC Policy baseline. The net benefits accruing to non-owner participants and customer-generators are also higher relative to Policy Path A. Notably, under an uncapped Policy Path B scenario, the total net benefits to non-owner participants are significantly higher than even the SREC Policy baseline, even as the expected costs to ratepayers are reduced. The specific net benefit values of Policy Path A relative to the SREC policy baseline are explored below.

Discussion of Findings

Build-out under Each Scenario

Figure 1 shows the projected subsector market share in each policy future after 2016. No policy future is projected to reach the level of share of Managed Growth as has been seen in the past. Almost 20% of the cumulative installs through the end of 2016 are projected to come from the ≤ 25 kW subsector. In attaining the 2500 MW goal, this proportion declines slightly in all policy futures except SREC capped, which builds almost three times the cumulative installations in the ≤ 25 kW subsector as was seen in SREC capped scenario through 2016. In all policy futures cumulative installations in the Building Mounted subsector increase. The net metering policy clearly drives the cumulative installations of VNM LIH and CSS. In capped scenarios neither of these project types will be built, but when net metering is uncapped all scenarios show a hefty fraction of VNM LIH and CSS installs. The incentive structure of Paths A and B promotes more project diversity with and without net metering as compared to the SREC policy.

Figure 1: Subsector Market Share Comparison by Policy Scenario



Quantified Costs and Benefit Results

Table 1 and Table 2 summarize the results of the **quantified** cost and benefit analysis for each policy scenario, as follows:

- **Net Present Value of Costs** – measured in 2015 $ million
- **Net Present Value of Benefits** – measured in 2015 $ million
- **Benefit to Cost (B:C) Ratio** – illustrates the trade-off between the cost and benefit to a perspective under each policy. A ratio larger than 1 indicates that the benefit to the perspective is greater than the cost.
- **Net Benefits to Citizens at Large to Net Costs to Non-Participating Ratepayers (NB(C@L):NC(NPR)) Ratio** – illustrates "which future justifies the subsidy paid by non-participating ratepayers with the greatest net benefits to the Commonwealth at large?"

Table 1: Quantified Cost and Benefit Results and Ratio: SREC (Capped), Policy A (Capped), and Policy B (Capped) to 2500 MW

SREC Capped		2500 MW NPV
NOP	NPV of Costs	$ 318.0
NOP	NPV of Benefits	$ 1,127.1
	B:C Ratio	3.54
CG	NPV of Costs	$ 8,931.6
CG	NPV of Benefits	$ 12,668.0
	B:C Ratio	1.42
NPR	NPV of Costs	$ 8,757.8
NPR	NPV of Benefits	$ 5,047.8
	B:C Ratio	0.58
C@L	NPV of Costs	$ 5,526.9
C@L	NPV of Benefits	$ 14,358.2
	B:C Ratio	$ 2.6
NB(C@L):NC(NPR) Ratio		2.38

Policy A Capped		2500 MW NPV
NOP	NPV of Costs	$ 340.4
NOP	NPV of Benefits	$ 1,239.3
	B:C Ratio	3.64
CG	NPV of Costs	$ 9,312.3
CG	NPV of Benefits	$ 11,540.0
	B:C Ratio	1.24
NPR	NPV of Costs	$ 7,702.9
NPR	NPV of Benefits	$ 5,316.3
	B:C Ratio	0.69
C@L	NPV of Costs	$ 6,035.8
C@L	NPV of Benefits	$ 13,721.1
	B:C Ratio	$ 2.3
NB(C@L):NC(NPR) Ratio		3.22

Policy B Capped		2500 MW NPV
NOP	NPV of Costs	$ 337.5
NOP	NPV of Benefits	$ 1,231.0
	B:C Ratio	3.65
CG	NPV of Costs	$ 9,058.4
CG	NPV of Benefits	$ 11,420.4
	B:C Ratio	1.26
NPR	NPV of Costs	$ 7,488.5
NPR	NPV of Benefits	$ 5,282.0
	B:C Ratio	0.71
C@L	NPV of Costs	$ 5,606.2
C@L	NPV of Benefits	$ 13,753.8
	B:C Ratio	$ 2.5
NB(C@L):NC(NPR) Ratio		3.69

Table 2: Quantified Cost and Benefit Results and Ratio: Policy A (Capped) and Policy B (Capped) to 2500 MW

Policy A Uncapped		2500 MW NPV
NOP	NPV of Costs	$ 196.8
NOP	NPV of Benefits	$ 1,233.2
	B:C Ratio	6.27
CG	NPV of Costs	$ 8,670.5
CG	NPV of Benefits	$ 10,966.0
	B:C Ratio	1.26
NPR	NPV of Costs	$ 6,927.9
NPR	NPV of Benefits	$ 5,178.0
	B:C Ratio	0.75
C@L	NPV of Costs	$ 5,271.6
C@L	NPV of Benefits	$ 13,486.0
	B:C Ratio	$ 2.6
NB(C@L):NC(NPR) Ratio		4.69

Policy B Uncapped		2500 MW NPV
NOP	NPV of Costs	$ 245.7
NOP	NPV of Benefits	$ 1,516.6
	B:C Ratio	6.17
CG	NPV of Costs	$ 9,423.8
CG	NPV of Benefits	$ 11,342.9
	B:C Ratio	1.20
NPR	NPV of Costs	$ 7,687.9
NPR	NPV of Benefits	$ 5,218.0
	B:C Ratio	0.68
C@L	NPV of Costs	$ 4,989.0
C@L	NPV of Benefits	$ 13,584.5
	B:C Ratio	$ 2.7
NB(C@L):NC(NPR) Ratio		3.48

Comparing Cost and Benefit Results by Perspective

- **NOP benefits include value of production (on-site and net metered), land lease and PILOTs/property taxes.** Variations in benefits to NOPs between policy scenarios are mostly a function of the proportion of projects using virtual net metering. State and federal income taxes make up the total costs to NOP. NOP total benefits and total costs are relatively small in comparison to other perspectives.
- **CG benefits and costs drive profitability.** The largest costs to CGs are system installed costs, ongoing O&M, and taxes. Direct solar incentive revenues make up almost 30% of total benefits in some policy scenarios. Other major benefit sources are virtual net metering and federal ITC, which makes up 10 to 12% of CG benefits depending on the scenario.
- **NPR costs and benefits tell the degree of subsidy that they are bearing.** Benefits to NPRs are similar across the policy scenarios. Major cost components to the NPR perspective include direct solar incentive payments, which make up about 50% of total costs. Other large cost components include non-generation components of on-site generation and VNM.
- **Massachusetts Citizens at Large (C@L) costs and benefits are the justification to have a solar policy.** Costs to C@L include federal income taxes, direct incentives, and solar policy administrative and transaction costs. The largest benefits to C@L are system installed costs retained in state, avoided generation capacity costs, and generation value of on-site generation.

Comparing Cost and Benefit Results by Policy Scenario

- **Policy Path A (Uncapped) would translate non-participating ratepayer's subsidy to the greatest net benefits to the Commonwealth at large.** Among the six policy scenarios, Policy Path A (Uncapped) has the highest NB(C@L):NC(NPR) ratio of 4.69.
- **Policy Path A (Uncapped) represents multiple perspectives' best interest.** Among the six policy scenarios, Policy Path A (Uncapped) has the highest B:C ratios for two perspectives (non-owner participants and non-participating ratepayers). SREC (Capped) has the highest B:C ratio for customer generators. Policy Path B (Uncapped) has the highest B:C ratio for the Commonwealth at large.
- **Non-participating ratepayers fare better under Policy Path A or B**. Non-participating ratepayers receive B:C ratios below 1 across all policy scenarios, although the ratio increases when moving away from the SREC scenario. This shows that, while a subsidy is paid by non-participating ratepayers for each policy, Policy Path A and Policy B requires less subsidy than the SREC program to build the same amount of solar.
  It is important to note that the result of non-participating ratepayers costs exceeding benefits over the entire time horizon since 2010 is largely driven by inclusion of the legacy programs, SREC-I and to a lesser degree SREC-II. The subsequent programs – SREC-III, Policy Path A and Policy Path B, each are progressively more cost-effective than the legacy programs. While the scope of the analysis did not allow for rolling up costs in this manner, inspection of the results suggests that part or all of these policies may have a B:C ratio near or exceeding 1.0, which would indicate any subsidies being offset by tangible internalized benefits.

Availability of net metering incentives is crucial to non-owner participants. The B:C ratios for non-owner participants are significantly higher under Policy Path A (Uncapped) (6.27) and Policy Path B (Uncapped) (6.17) than under other scenarios. This can be explained by the dependence of non-host-owned projects (such as Community Shared Solar and low-income housing with virtual net metering) on the availability of virtual net metering.

Acronym Glossary

C@L	Citizens of the Commonwealth at large
CG	Customer-Generator
CSS	Community shared solar
DBI	Declining block incentive
DRIPE	Demand reduction induced price effect
EDC	Electric Distribution Company
ELCC	Electric Load Carrying Capacity
EPBI	Expected Performance Based Incentive
FCM	Forward Capacity Market
ICR	Installed Capacity Requirements
ISO-NE	Independent System Operator (New England)
kW	kilowatt
kWh	kilowatt-hour
LIH	Low-income Housing
MW	Megawatt
MWh	Megawatt-hour
NM	Net energy metering
NMC	Net metering credit
NOP	Non-Owner Participant
NPR	Non-Participating Ratepayer
PBI	Performance-Based Incentive
PV	Photovoltaic(s)
REC/RECs	Renewable energy certificate(s)
SACP	Solar alternative compliance payment
SREC/SRECs	Solar renewable energy credit(s)
VNM	Virtual net metering

1 Introduction

1.1 Objectives: Framework and Boundaries of Analysis

The Massachusetts Net Metering and Solar Task Force ("Task Force") was created by Senate Bill 2214, which was signed into law August 6, 2014. Among other responsibilities, This Act requires the Task Force to "assess and report to the legislature on the costs and benefits of the existing net metering framework from the perspectives of the customer-generator, non-participating ratepayers and the citizens of the commonwealth at large."1 Task 3 of the Task Force consultant's scope of work is to "Analyze the costs and benefits of current Massachusetts net metering and solar incentive policy and compare to other policies from the perspective of groups the customer-generator, non-participating ratepayers and citizens of the commonwealth at large, provided that the task force may further specify groups." Further, Task 4 of the scope of work was to "provide a range of options for appropriate structures for providing the support to reach the 1600 MW goal and provide the opportunity for additional development".

The purpose of this report is threefold:

- **To evaluate the costs and benefits of the current solar and net metering incentive landscape**. This includes the interaction between the current solar policy – a Solar Carve-out from the Commonwealth's Class I Renewable Portfolio Standard (RPS) which utilizes a tradable market for Solar Renewable Energy Credits (SREC)s – and the current net metering policy, which caps the quantity of 'behind-the-meter' distributed renewable energy generators at a specified percentage of each distribution utility's loads for 'public' and 'private' installations.[2]

- **To compare the current policy landscape with alternative future policy 'paths' and inform the Task Force and policy makers regarding the impact of changes to net metering and solar policy in Massachusetts**. This includes two alternative future solar policy paths selected for analysis through consultation between the Task Force and consultants, under two alternative net metering futures, limited to current statutory caps, and without any net metering cap (referred to herein as 'uncapped').[3]

- **To calculate and present the costs and benefits of each future policy path from specified stakeholder perspectives, through the current level of policy targets (1600 MW_{DC} of solar photovoltaic (PV) capacity in Massachusetts) and beyond**. As discussed further below, in order to capture impacts of interest to Task Force members and allow for a more meaningful

[1] See Section 7(b) of Chapter 251 of the Acts of 2014 (https://malegislature.gov/Laws/SessionLaws/Acts/2014/Chapter251) and the Net Metering Task Force Framing Memorandum (http://www.mass.gov/eea/docs/dep/about/final-nm-task-force-framing-memo.pdf)

[2] The current public sector and private sector net metering caps are set at 5% and 4% of a distribution company's historical peak load respectively. See Section 5 of Chapter 251 of the Acts of 2014 (https://malegislature.gov/Laws/SessionLaws/Acts/2014/Chapter251) and 200 CMR 18.00 (http://web1.env.state.ma.us/DPU/FileRoomAPI/api/Attachments/Get/?path=14-104%2f14104A_order_App_A.pdf).

[3] Class I net metering systems (≤10 kW on a single-phase circuit or ≤ 25 kW on a three-phase circuit) are not counted against the aggregated program caps and therefore can continue to net meter under the capped scenarios.

consideration of costs and benefits to citizens within the Commonwealth, a fourth perspective was added to those identified in statute: that of non-owner participants.

Costs and benefits of interest relate both to the impacts which relate to the quantity of solar PV in Massachusetts (which are in most respects independent of the policy future chosen), and the costs and benefits that differ between futures. While this report considers both absolute and relative costs and benefits, the Task Force was clear in prioritizing those costs and benefits that differ between futures:

> *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.*[4]

Many of the absolute costs and benefits considered are the same (or nearly so) between alternative policies reaching similar quantities of solar in MA. Those most important are those that clearly differ, e.g. solar policy payments and net metering transfers.[5]

1.2 Cost-Benefit Perspectives: An Overview

When evaluating the costs and benefits of energy programs or policies, it is important to remember that costs and benefits do not have a single objective value. Since electric power generation, transmission, distribution (as well as conservation) have an impact on an economy and society on multiple levels, multiple "objective" and equally valid cost-benefit values can be accounted for from multiple perspectives. And the costs to one party may be benefits to other parties (and vice versa).

Perspectives of interest can include both "participants" that are directly affected by or benefiting from the program, as well as non-participants, including both electric ratepayers, as well as others who may be affected indirectly as non-participants.

The Task Force in consultation with the consultants has explicitly identified four cost-benefit perspectives to account for:

- Participants (including two subcategories):
  - **Customer-generators (CG)**, which includes individuals and businesses owning and operating grid-tied solar PV systems;
  - **Non-Owner Participants (NOP)**, which includes other entities that directly benefit from solar PV installations.
- **Non-participating Ratepayers (NPR)**, which includes all utility customers not participating in a solar PV program; and
- **The citizens of the Commonwealth at large (C@L)**, which includes all citizens of Massachusetts, including all participants and non-participating ratepayers.

The term "customer-generator" frequently refers to owners of solar PV systems, but can sometimes be used interchangeably in utility tariffs to refer to both owners and non-owning customer beneficiaries. Given that a large number of on-site (as well as off-site

[4] Net Metering Task Force Framing Memorandum.

[5] Little can be learned from analysis of market price effects, avoided emissions or transmission system impacts between different solar policies of similar scale, so cost or benefits proportional to quantity of solar PV were analyzed once for a proxy build-out schedule and applied equally on a per-unit basis to all cases, a reasonable simplification allowing the consulting team to focus on the Task Force's priorities.

and "virtually" net metered) solar PV systems in Massachusetts and elsewhere are owned and operated by third parties (referred to herein as 3rd-party owners, or 3POs), a clearer definition of "customer-generator" is beneficial to the analysis. At the request of DOER, the analysis also includes the perspective of the non-owner participant in a solar program or other arrangement. Table 3 below describes the types of individuals and businesses that are both solar customer-generators and non-owner participants.

Table 3: Summary of Four Perspectives

Participants		NPR: Non-participating Ratepayers (within MA)	C@L: Citizens of MA at Large
NOP: Non-Owner Participants	**GC**: Customer-generators (Including Host- and 3rd-Party (3PO) System Owners)		
Including individuals, businesses, governments and non-profits that receive economic benefits through solar PV transactions with 3POs, and communities receiving property tax or similar benefits: • Communities hosting PV • Net Metering Credit (NMC) off-takers • Hosts of systems purchasing electricity from 3POs or selling Virtual net metering credits (VNMCs)	Individuals, businesses, governments and non-profit organizations that own an eligible solar PV system for self-supply as "host owners" or "public owners" and receive net metering credits, as well as 3POs, businesses that own eligible systems and sell energy to participants as a third party.	Customers of electric distribution companies (EDCs) and competitive suppliers that do not own or contract for energy from a dedicated distributed solar PV system or receive direct bill savings that may accrue electric system benefit or cost as a result of net energy metering.	**Sum** of all in-state participants and in-state non-participants. Individuals including both non-ratepayers and both participating and non-participating ratepayers that may accrue economic, environmental or other social benefit or cost as a result of solar PV.

The set of four perspectives described here are defined in such a manner that, if all cost and benefit components were able to be quantified, all impacts would be captured other than dollars flowing out of state. As discussed above and further below, however, this analysis does not include macroeconomic indirect and induced benefits. And further, there are certain cost and benefit components that are not captured because they are ether difficult to quantify, controversial in nature, small and therefore ignored, beyond the scope of this engagement. Several of these cost components are addressed qualitatively, so that readers may consider their role in the overall analysis were they able to be included.

The analysis treats customer-generators (CGs) themselves as in-state entities, but then treats (or apportions) the dollars that flow to both in- and out-of-state investors (owners and lenders). Further, it apportions dollars spent on equipment and labor both in- and out-of-state.

1.3 Baseline for Comparing the Costs and Benefits of Alternative Policy Futures

In order to establish an appropriate baseline for comparing costs and benefits of various policy futures from multiple perspectives on a per-unit basis, it is important to consider the *counterfactual* to the alternatives being considered, i.e. *compared to what*? Most studies of solar policy compare solar PV to the absence of a solar policy in which solar PV would displace the marginal fossil fuel (in New England, primarily natural gas). However, the current solar policy is structured as a 'carve-out' from the Massachusetts Class I Renewable Portfolio Standard (RPS). This means that the solar policy operates *within* the Class I RPS; the existence of the carve-out reduces the net Class I RPS obligation to be met by other Class I RPS sources.

From this perspective, if Massachusetts load-serving entities (LSEs) subject to the Class I RPS obligation were able to procure sufficient Class I-eligible Renewable Energy Credit (REC) supply (assumed to be sourced primarily from land-based wind projects at the margin), then the solar would in effect be displacing such wind power (most likely located in Northern New England), in terms of its power market and emission impacts, and the purchase of Class I RECs for RPS compliance. On the other hand, of the obligated LSEs were unable to procure sufficient Class I REC supply because developers were unable to develop sufficient volumes of wind power to meet RPS targets, then the solar PV in Massachusetts would be displacing primarily natural gas generation in terms of its power market and emission impacts, and the payment of Class I Alterative Compliance Payments (ACPs) for RPS compliance.

This study considers these two frameworks as extremes:

- **The Carve-out Framework (solar vs. wind**): In this framework, it is assumed that in the future, if not for the solar carve-out or any alternative Massachusetts solar policy, sufficient supply from land-based wind would be built, with corresponding Class I RECs purchased sufficient to meet the Class I RPS. With this as the policy baseline, adding solar displaces wind power, a zero emission resource with a materially different production profile, and avoids LSE payments for Class I RECs. It is assumed that prior to 2018, in the absence of the Massachusetts solar carve-out policy, no more wind could be built: the past supply mix is held constant, and prior to 2018 it is assume no more wind could be brought forth, so until 2018, solar is assumed to displace natural gas; thereafter. This framework represents the low end of emission reduction, market price effects (i.e. energy market price suppression), and avoided Class I REC costs.
- **The Incremental Solar Framework (solar vs. natural gas)**: In this framework, it is assumed in the future that in the absence of Massachusetts solar PV policy, not enough wind power can be successfully sited or built to fulfill the Class I RPS obligation. In this case, solar PV avoids burning natural gas. This framework represents the high end of emission reduction and market price impacts, as well as avoidance of higher cost Class ACPs Class I RPS shortfalls.

A more realistic future than either of these extremes is somewhere in between. For purposes of this analysis, costs and benefits are calculated under both frameworks and their results are presented based on a 50%/50% weighting of the extremes. The results are later tested to understand the sensitivity of the results to either extreme.

1.4 Analysis Timeline and Installed Capacity Targets

This analysis seeks to answer the question: how much has the SREC program in combination with net metering and virtual net metering of solar PV systems in the state cost and benefited stakeholders since their outset, compared to if we had no such policies? In order to assess the costs and benefits of the current policy, this analysis commences in 2010, at the commencement of the SREC-I policy, the initial tier of the Massachusetts solar carve-out. The analysis therefore consider the costs and benefits of consisting of a common past, the SREC-I and SREC-II solar carve-out ties since their inception in 2010 and 2014, respectively, to the present, and then a series of alternative policies into the future. In considering past costs and benefits associated with solar PV already operating, the analysis incorporates a series of sunk costs constant across all futures. This information is informative but has no value to future policy alternative decisions. Instead, it characterizes costs of policies to date as a benchmark for identifying trends (improvement over time) and benchmarking the performance of future alternatives.

The analysis horizon selected considers a period of installations from 2010 through 2025, plus an assumed 25 year solar PV project life, taking the full analysis out through 2050. It is important to note that the current policy target of 1600 MW_{DC} of solar PV is expected to be reached well before the initial target date of 2020 (as discussed further below), and that most of the progress towards 1600 MW will be made before the 30% Federal Income Tax Credit (ITC) steps-down to 10% for businesses and 0% for residences at end of 2016, and likely before any policy change could be implemented. It is also important to observe that if a transition from SREC-II to a new policy is made prior to reaching 1600 MW, the SREC-II policy build-out and associated SREC-II prices will change. In contrast, SREC-I quantities are now firmly established and associated SREC unaffected by any change short of abolishing the SREC-I policy (which we assume is not on the table).

As noted in Section 1.1, the Task Force was interested in examining the opportunity for additional development, i.e. solar PV build-out beyond 1600 MW. For the purposes of this analysis, in consultation with the Task Force an arbitrary target was established of reaching 2500 MW by the year 2025. Each alternative policy future was tuned to target approximately 2500 MW under 'base case' assumptions. Setting a constant MW target across alternative policy futures allows comparison of costs and benefits without conflating impacts driven by the volume of production (which drives many benefits) and the solar and NM incentive costs, and this avoids masking important policy impacts that differ by virtue of different penetration. If instead we had held incentives constant (and let the MW vary), net metering capped paths would experience a much slower build-out in all cases except for a competitive solicitation, under which annual targets can be set and maintained..

There is nothing special about 2500 MW or 2025, other than an analysis assumption. The choice of these benchmarks is not intended to suggest them as recommendations. However, the reader should note that 2500 MW by 2025 represents a substantial contraction of the Massachusetts solar PV market's annual build-out rate from its present levels. It is important to keep in mind that some sectors would not be largely impacted by net metering policy changes and would continue to be viable, while others would no longer be viable. It is expected that the industry would contract with the ITC step down and hitting caps on net metering, all else held constant, until solar costs decline materially. It is also important to point out that conditions under each future considered will lead to a different build-out trajectories.

Modeling results are driven in large part by fixing a target of 2500 MW and *trying* to set incentives so they reach that level in 2025, and tallying what will be built under those circumstances and at what cost. Results are assess for costs and benefits through 1600 MW, as well as to 2500 MW.

1.5 Limits to this Analysis

Several boundaries to the analysis were established, either by time and budget constraints, modeling complexities, or Task Force decisions. Limits to the analysis include the following:

- **Not a full macroeconomic analysis.** This analysis does not considers indirect and induced macroeconomic impacts in the Massachusetts economy, nor does it quantify job additions or losses relating to solar PV and net metering policy alternatives..
- **Not a 'value of solar' study.** While this report shares many common cost and benefit components, it should not be construed explicitly as a "value of solar" study.[6]

[6] In recent years, a variety of state-level policy makers and stakeholders have requested formal analyses of the value of solar PV as part of ongoing state policy discussions. These "value of solar" studies generally examine the specific benefits and costs of solar to the market, the utility's grid and/or society at large.

- **Retail Rate Structures Held Constant.** The analysis assumed no change in retail rate structures from the present, with respect to any shift from components billed on a per-kWh basis to fixed charges, customer charges, or the establishment of minimum bills. Task Force determined that rate design is important but best addressed before the DPU. A future shift in rate structure away from kWh charges would reduce the avoided cost or revenue realized for behind-the-meter or net metered solar PV projects. Such changes would in turn diminish PV system economics, leading to a slower build-out and a potential shift among installation types unless solar incentives were increased to match (as might be the case under Paths A and B discussed further below).
- **Targeted incentives to support solar PV projects that support or benefit the Distribution system were not considered.** In Task Force discussions and surveys, higher incentive for supporting projects that support the Distribution system had near unanimous support. However, the electric distribution companies (EDCs) point out that there is not currently system-wide information on which to base modeling if such installations. There appears to be wide support among Task Force members that targeting incentives in this manner could provide additional net benefits. However, this is seen as an area for further study and a tactic that could be layered into any potential future policy**.**

1.6 Structure of This Document

The Task 3 report is organized as follows.

- Section 2 presents the description of the future policy scenarios, or 'policy paths', examined.
- In Section 3, technical factors which permeate a number of cost and benefit components of the analysis, including solar PV contribution to peak reduction and loss reduction, are described.
- Section 4 describes the various cost and benefit categories and components analyzed.
- In Section 0, the projected solar PV build-out trajectories are presented, including (i) the incremental MW_{DC} installation by program under each policy path, as well as (ii) the build-out under each scenario by SREC-II project type subsector, demonstrating that different policy choices lead to notably different build-out results.
- Section 6 summarizes the projected per unit solar policy incentives under both the SREC and alternative performance-based incentive structures.
- In Section 7**,** the costs and benefits under the current SREC policy approach (including an "SREC-III extension") are presented.
- Comparative cost and benefit results are presented by perspective, across each of the alternative policy futures, in Section 8.
- Section 12 provides a summary comparison of the quantified costs and benefits across policy scenarios, including calculation of benefit to cost and other useful summary metrics.
- Section 9 includes a discussion of certain cost and benefit components that are treated qualitatively in nature, in particular jobs impacts and resiliency.
- A sensitivity analysis of certain factors that are treated parametrically if found in Section 10**.**
- Section 11 summarizes the projected avoided fuel use and emissions results.
- Finally, Section 12 includes conclusions, take-aways and observations to assist the Task Force in making its recommendations, as well as limitations of the analysis and suggested areas of further study.

Appendices are included with the following information:

- Appendix A: Key Assumptions (PPT)
- Appendix B: Detailed Cost and Benefit Result Tables (PPT)
- Appendix C: Policy Path A&B Modeled Incentives (PPT)
- Appendix D: C-B Components (Word)
- Appendix E: Distribution and Local Transmission Deferral (Word)

2 Scenarios: Current Policies and Alternative Futures

This analysis compares the impact of a solar carve-out policy to two alternative policy futures. A reference case ("Current Policy" case) was developed to calculate the expected impact resulting from current solar and net metering policies in Massachusetts. An extension of the current SREC policy, modeled as a distinct SREC-III tier, was also modeled to reflect the costs and benefits of allowing the current policy approach to continue to 2500 MW. In addition, two alternative solar policy cases ("Alternative Policy Path A," and "Alternative Policy Path B"), described further below were modeled.

In total, a series of six policy combinations, or futures, were modeled – consisting of three alternative solar policy and net metering pricing approaches, combined with two alternative approaches to net metering caps – over two capacity targets (to 1600 MW and to 2500 MW).

- **Solar policy** – solar-specific policy incentive and programs designed to reach the installed capacity target within the defined timeline, including:
    - the SREC carve-out approach;
    - Policy Path A, which consists of a 15-year performance-based incentive (PBI) distributed through a declining block incentive (DBI) for small solar PV installations and a 15-year PBI distributed through a competitive bidding process for larger solar PV installations;
    - Policy Path B, which consists of an *expected PBI* structured as a rebate for small solar PV installations and a 15-year PBI distributed through a declining block incentive (DBI) for larger solar PV installations;
- **Net metering policy** –
    - net metering rates as established under current law, or an alternative paying just the generation portion of rates; and
    - different availability of net metering caps for each customer class and project type: a "capped" scenario represents a policy future where existing net metering caps will not be increased; an "uncapped" scenario represents a policy future where existing caps are removed and net metering will be available indefinitely.
- **Installed capacity target** – defined as the *target* megawatts of PV capacity installed, tallied through 1600 MW and through 2500 MW. While the annual MW *targets* under each policy scenario was selected to bring the total installed MW to 2500 MW by the end of 2025, note that under SREC and declining block incentive (DPI) policy types, once established, economics and market response may not keep to the target schedule.

The SREC uncapped future (requiring modeling of an SREC-III policy in an environment devoid of net metering caps) was subjected to preliminary analysis; because its modeled behavior was so radically different from other alternatives (for example, reaching 2500 MW by 2020) and introduced other modeling complexities[7], it was not further subjected to the full benefits and costs analysis.

These futures are summarizes in **Table** 4, and described further through the remainder of this section.

[7] Under this case, DOER's supply-responsive demand formula is projected to break down due to extremely high installation growth rates at the end of the program.

Table 4: Scenarios Taxonomy: Policy Paths Modeled

	Current Policy (SREC)		Option A (New Policy Start date: 1/1/17)		Option B (New Policy Start date: 1/1/17)	
Solar Incentive Features	10-year market-based SRECs with floor price auction		Small: 15 yr DBI/PBI Large: Competitive Bid for PBI		Small: 15-yr DBI/EPBI as Rebate Large: DBI/PBI	
Net Metering	Current Approach, Rate Structure		Reduced Value for Excess MWh		Current Approach, Rate Structure	
	Capped[4]	Uncapped	Capped[4]	Uncapped	Capped[4]	Uncapped
SREC-I,II	a	b	c[1]	d[1]	c[1]	d[1]
SREC-III	e[2]	N/A	-	-	-	-
New Policy	-	N/A	g[3]	h	i[3]	j
New Policy Solar Target (MW)	1,600/2,500	1,600	1,600/2,500	1,600/2,500	1,600/2,500	1,600/2,500

Notes on* Table 4*:

1. SREC-II truncated at 12/31/16

2. Starts when 1,600 MW is reached

3. Ignores very small quantity of cap space expected to be available in 2017 (~ 25 MW)

4. Remember, NM Capped ≠ NM Eliminated: when capped, small systems can still net meter, and sized-to-load still avoid retail value

Large-scale CSS, Offsite Low Income as we know them no longer viable once NM capped

2.1 Current Policy Component of "SREC Policy" Case (SREC-I and SREC-II)

For the "Current Policy" case, the current SREC-I and SREC-II are modeled through their envisioned conclusion, reaching the 1,600 MW installed solar PV capacity in total, after which no new solar policies will be introduced. This case serves as the reference case for comparing the impacts of other policy designs. A capped net metering scenario, where existing net metering caps will not be extended once reached (systems ≤ 25 kW will continue to be eligible for net metering), and an uncapped net metering scenario were examined. The uncapped scenario is expected to accelerate the solar installation rate, thereby shortening the timeline for achieving the 1,600 MW target.

2.2 Extension of Current Policy in "SREC Policy" Case (SREC-III)

The "Extension of Current Policy" Case represents a policy future where the solar carve-out continues to be the primary driver of solar PV deployment in Massachusetts. This case assumes that the solar carve-out program will be extended to achieve an aggregate program goal of 2,500 MW by 2025. It is assumed that the extension will be implemented as a distinct third phase of the solar carve-out program (SREC-III) rather than an extension of the existing SREC-II, as changing targets to SREC-II would impact the economics of past investments. SREC-III is *designed* to achieve an installation of 900 MW of solar PV over the remaining time between the 1,600 MW target is reached under SREC-II and the end of 2025. However, as shown in Section **[cross-ref]** below, the nature of the policy makes it amenable to surpassing its targeted timetable if the economics of market sectors other than the 'managed growth' sector allow for ample development. The SREC-III policy is assumed to be characterized by extending the trend of SACP and floor price declines from those built into SREC-II policy. Additional information about the definition and modeling of SREC-III is included in Appendix A.

The "Extension of Current Policy" case was only modeled for the full benefits and costs analysis under a net metering capped scenario, where net metering caps are assumed to be full by the time the 1,600 MW is reached and SREC-III is launched.

2.3 Alternative Policy Paths

Following the consulting team's presentation of future policy options and Task Force feedback, consultation and deliberation under Task 4, two alternative policy paths were developed to allow for comparing the impact of different policy design approaches to the current solar carve-out policy. These are labeled as alternative Policy Path A and alternative Policy Path B. Each of these policy paths is defined by varying a set of both solar and net metering incentive features. Furthermore, each has been cleaved into two distinct solar incentives that differ in approach within as well as between each policy path, one for small installations under 25 kW, and another for larger installations. In bifurcating the incentive structures in this manner, the Task Force intended to acknowledge its agreement on the challenges of applying a competitive model to smaller installations. The 25 kW cutoff was elected as a modeling convenience which enabled the assumption that virtually all small installations would not be counted against net metering caps (as is the case under current statute). However, the Task Force understands this cutoff to not be set in stone, and some expressed interest in a cutoff at some higher kW level.

In order to simplify modeling while revealing maximum learning, both policy paths assume that SREC-II will be truncated on December 31, 2016 notwithstanding (and not reaching) the current 1,600 MW target. It is further assumed that the new policies prescribed in each path will take effect on January 1, 2017 after the end of SREC-II and the federal ITC "cliff". While some other form and timing of transition may be desired, it is assumed that all projects coming online before this cutover date are installed under the SREC regime, net metering compensation scheme and selected net metering cap treatment, and all installations thereafter under the new incentive regime. Each alternative policy path is designed to achieve 2,500 MW of installed solar capacity, and in modeling each, the consulting team designed the incentive amounts to reach 2500 MW by the end of 2025 under the base case projections for solar PV installed costs, operating costs and retail rates.[8] The Task Force requested on testing each policy path under two variations, with the current statutory net metering caps and with all net metering caps removed.[9]

Selection of the two policy paths was informed by the policy path survey and related discussions. Both paths utilize policy design features intended to drive down the cost premium of solar over time and while providing solar PV installations with sufficient revenue to attract investment. These policy paths were selected to (i) test a diversity of solar incentive payment structures deemed appropriate for different market segments; and (ii) represent different perspectives of stakeholders. In electing these paths, the Task Force considered these policy paths to be fairly extreme "goalposts". Path A is labeled as an ***EDC-Centric Future featuring Competitive Solicitations and Net metering Credit (NMC) Value Reduction***, and represents many of the features favored by the electric distribution companies (EDCs) and others most interested in minimizing the cost of solar support (although not uniformly meeting any particular Task Force member's wish list). Policy Path B is labeled as an ***Open Declining Block Incentive*** (DBI) approach, and is more closely aligned with solar industry participants' and advocates' preferences for an 'open policy' (without an EDC and solicitation gatekeeper role on what gets built) structured to spur increased development. Members of the task Force acknowledged

[8] Under the Declining Block Incentives portions of both paths, the ultimate build-out rate could vary materially under different cost and retail rate futures. In contrast, a competitive solicitation regime as assumed under Policy Path A (Large) can set specific targets and therefore can more predictably meet specified annual MW targets.

[9] While there is an interest in understanding the impacts of a minimum bill policy, the Net Metering Task Force agreed that the effort to design and analyze a minimum bill policy would be extensive and beyond the scope of this study. Further, such an analysis would depend heavily on the details. As a result, minimum bill is not modeled in both policy paths but addressed through illustrations under Task 5. Further, the Task Force agreed that it would be the most appropriate for the DPU to conduct a study on the design and applicability of a minimum bill policy.

that the selection of these goalposts was intended to inform, but understood them to be extremes between which some future compromise might lie. The key features of Policy Paths A and B are described at a high level in Table 5 and Table 6 respectively.

Table 5: Policy Path A: EDC-Centric Future Featuring Competitive Solicitations and NMC-Reduction

Dimension	Description	Notes
Solar Small: Type	15-yr Performance-Based Incentive (PBI)	
Solar Small: Setting	Declining Block Incentive (DBI) w/ Safety Valve, i.e. may increase based on established administrative process if conditions warrant	May be modeled as declining incentive; allows simplification of analysis
Solar Large: Type	15-yr Performance-Based Incentive (PBI)	
Solar Large: Setting	Competitive Solicitation (pay as bid)	
Geog. Distribution	Solar incentives (not NM) vary by EDC, but MW available are a single statewide block.	Ex-post $ reconciliation btw. EDCs to equalize ratepayer impact
Differentiation by Market Sector	Based on SREC-II	
Sized-to-Load Net Metering	G Rate	Rate applicable to billing period roll-forward
VNM Credit Structure	W/S rate	Rate applicable to net excess after roll-forward
VNM Proj. Type Limitations	n/a	
VNM size limitations	n/a	
NM Caps	**Variations:** (A-i) No Caps; (A-ii) Current Caps	
Timing of Solar Policy Transition	1/1/17	Assume caps filled by time of transition
Targets and Timeline	Set targets ramping up to 2500 by 2025	proxy for possible 'budget-limited' approach
Min Bill	n/a	
Disposition of RECs	Assume RECs minted as Class I and resold into market	consistent with RI, CT approach

Table 6: Policy Path B: Open Incentive, DBI with Safety Valve

Dimension	Description	Notes
Solar Small: Type	"Expected" Performance-Based Incentive (EPBI), an upfront incentive (rebate) that is based on *expected* production over 15-yr period	Claw-back if underperforms. Similar to NY and as requested by several TF members.
Solar Small: Setting	Declining Block Incentive (DBI) w/ Safety Valve, i.e. may increase based on established administrative process if conditions warrant	May be modeled as declining incentive; allows simplification of analysis
Solar Large: Type	Performance-Based Incentive (PBI)	
Solar Large: Setting	15-yr DBI w/ Safety Valve	
Geog. Distribution	Solar incentives (not NM) vary by EDC, but MW available are a single statewide block.	Ex-post $ reconciliation btw. EDCs to equalize ratepayer impact
Differentiation by Market Sector	Based on SREC-II	[5]
Sized-to-Load Net Metering	Current components of retail rate	Rate applicable to billing period roll-forward
VNM Credit Structure	Current framework &rates	Rate applicable to net excess after roll-forward
VNM Proj. Type Limitations	n/a	
VNM size limitations	Keep current	
NM Caps	**Variations:** (B-i) No Caps; (B-ii) Align to match reaching 1,600 MW target	For B-ii, not on a % of peak load basis
Timing of Solar Policy Transition	1/1/17	
Targets and Timeline	2500 MW with no hard timeline	Calibrate modeled incentives to target 2500 by 2025
Min Bill	n/a	[7]
Disposition of RECs	Assume RECs minted as Class I and resold into market	consistent with RI, CT approach

A key feature of both policy paths is that they target the size of the combined solar and net metering incentive to effectively provide investors in solar PV installations what they need by in solar incentive after considering the value of value of both… i.e., if net metering revenues are unavailable or reduced, the solar incentive would be larger, while if retail rates increased, the solar incentive would shrink.

For ease of comparison, the eligibility and segmentation of the PBI incentives under Policy Paths A and B were defined to track the SREC-II Market Sectors shown in Table 7. These definitions were selected by the Task Force as a convenience, and were not meant to preclude alternative segmentation choices.

Table 7: SREC-II Market Sectors

Market Sector	Generation Unit Type
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
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
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.
Managed Growth	Unit that does not meet the criteria of Market Sector A, B, or C.

The following sections describe each policy path, their policy design features and modeling characteristics. Detailed methods and assumptions for the policy paths can be found in Appendix A.

2.4 Policy Path A: An EDC-Centric Approach

Policy Path A is designed to achieve 2,500 MW of installed solar capacity by 2050 through a combination of Declining Block Incentive (DBI) for small installations and competitive solicitations targeted at larger installations, each segmented into different market sectors. This policy path is considered an EDC-centric approach as it provides EDCs with more control over the solar PV market (through competitive procurement) compared to Policy Path B, where all incentive rates are administratively set. The reduced net metering credit rate structure also aligns with EDCs' view on how customer generation should be credited.

2.4.1 Solar Policy

Policy Path A is comprised of a performance-based Declining Block Incentive (DBI) program for small installations (systems <25 kW) and a performance-based competitive solicitation program for large installations (systems ≥ 25 kW).

2.4.1.1 Performance-Based Declining Block Incentive (DBI) Program (Small)

Unlike the larger project competitive program described below, the performance-based DBI (sometimes referred to herein as the PBI/DBI for short) is an open incentive available to a subset of projects that are currently eligible to be qualified for Market Sector A under SREC-II. Specifically, residential and small commercial (G-1) systems that meet the <25 kW system size threshold will be eligible to participate in the DBI program. The program will be divided into two segments: (i) Residential and (ii) Non-Residential. The

allocation of annual MW capacity target among the two segments is determined based on the projected MW distribution among the segments under SREC-II as projected through December 31, 2016.

The DBI is made up of a series of equal-sized incentive "blocks" (i.e., the MW available for each block will be constant over time) defined by Block Incentive Prices (measured in $/MWh). Each Block is sized at 50% of the allocated segment annual target. After a block is fully subscribed, the incentive price declines to a lower level based on a predefined schedule until it is fully subscribed, and so on. While these Block Prices vary by EDC territories (as requested by the Task Force in order to equalize attractiveness across EDCs), all participants will compete for capacity under the same Block. The initial Block Price is derived based on the levelized 15-year incentive required to build a benchmark project (selected by the consulting team) within the segment. The required combined incentive is universal across all EDC territories. The difference between the required incentive and the typical retail rate for an EDC is the offered solar incentive, or the EDC-territory-specific Block Price. The offered Block Price will decline per Block at a fixed rate predetermined based on an economic modeling exercise that accounts for projected annual installed cost decline and future retail and wholesale rate revenue. The DBI is understood to include a "Safety-Valve" feature, which means that the offered solar incentive may be adjusted upward based on an established administration process if market conditions or other factors warrant such an adjustment. This feature is not modeled in this analysis as it does not affect the modeling under a single cost forecast.

2.4.1.2 Performance-Based Competitive Solicitation Program (Large)

The performance-based Competitive Solicitation program is offered to all remaining solar PV systems too large to participate in the DBI. The program is divided into four segments defined based on current market sector definitions under SREC-II. The allocation of annual capacity target is the remainder of the total annual targets required to reach 2500 MW by 2025, after allocation of capacity to the small program. Of this remaining capacity, the MWs available are allocated among the four segments as shown in Table 8. It should be noted that under the capped net metering scenario, community-shared solar and low-income housing projects under Sector A are assumed to be unviable once the net metering caps are reached. In this situation, 15% of the MW allocation was shifted from Sector A to the "Other" sector, as discussed further in Appendix A.

Table 8: Definition of Program Segment

Competitive Solicitation Program Segment	Corresponding SREC-II Market Sector	% Annual MW Allocation, NM Uncapped Scenario	% Annual MW Allocation, NM Capped Scenario
Sector A	Sector A (systems ≥ 25 kW only)	25%	10%
Sector B	Sector B	25%	30%
Sector C	Sector C	25%	30%
Other	Managed Growth	25%	30%

While it is assumed that the competitive solicitation will occur three times a year (a frequency assumed sufficient to allow for establishment of permanent in-state jobs),for modeling purposes it is treated as occurring four times per year (as the model is built for calendar quarters). Systems within each segment across all EDC territories will compete head-to-head based on price for each round of solicitation. Participants will bid at a levelized combined incentive (i.e., solar incentive plus the typical EDC rate within each territory). Selected projects will enter into a 15-year long-term contract (or convey under a tariff) to sell RECs and (where not consumed on-site) energy to the EDC of which territory the project is located. The selected project will receive payment for its production at a level that equals the difference between the bid price (i.e. the levelized combined incentive) and the EDC rate for the

given year.[10] While selected bidders will be paid as bid, it is expected that the market will learn after the first several rounds and the most cost-effective projects will eventually bid up toward the clearing price.[11]

As observed in other states, competitive procurements can put downward pressure on profit margins and convey advantage to scale. This phenomenon is typically associated with national players achieving scale economies and access to lowest cost equipment, financing, overhead, etc., potentially to the disadvantage of smaller, more local market participants. There is only anecdotal evidence on the degree of this impact, so it was not explicitly reflected in the projected costs and benefits in this analysis.

2.4.2 Net Metering Rates

Policy Path A provides a variation to the existing net metering program. It assumes that all on-site physical consumption and energy deemed to offset usage within the current billing month will be credited at a total avoided rate. Beyond that level, generations will receive only the G(eneration) component of rate for any excess production. For Virtual Net Metering customers, any excess generation after the billing period roll-forward will be credited at the wholesale rate (whether conveyed under Qualifying Facility (QF) rates or directly through participation in the wholesale market).

2.5 Policy Path B: Open Incentive

Policy Path B is made up of two Declining Block Incentive DBI) programs that are supported by the current net metering rate structure. Given that incentive levels are administratively predetermined across all market segments, EDCs do not determine who receives an incentive under this policy path, or when. A DBI approach is by definition designed to reach a 2,500 MW installed capacity target with no defined timeline – reaching a target when economics dictate - although for this analysis, the program incentives and their rate of decline were calibrated to reach 2,500 MW by 2025 to allow for cost and benefit comparison across alternative futures.

2.5.1 Solar Policy

Policy Path B is comprised of two DBI programs. An "Expected" Performance-Based DBI program is available for small installations (systems <25 kW). A Performance-Based DBI Program is available for remaining installations (systems ≥ 25 kW).

2.5.1.1 "Expected" Performance-Based Declining Block Incentive (EPBI) Program

The EPBI is modeled after New York's Declining Block Incentive program. Unlike a conventional PBI where incentives are awarded post-installation based on actual system production, the EPBI provides upfront incentives in the form of a rebate based on "expected" production over a 15-year period.[12] As with the small component of Policy Path A, the program is offered to systems

[10] Note in the uncapped scenario where net metering is available the combined incentive is still based on the EDC rate for assuming that the project is sized to load and all of its kWhs are consumed on-site during the billing month.

[11] The authors' extensive experience studying and modeling such procurements suggests that this dynamic should be expected. As a result, the projected bid prices received are taken as the midpoint between the fully-differentiated threshold incentive modeled as needed, and the price of the last (most expensive, marginal) bid awarded.

[12] An EPBI would conveys RECs to the EDCs for 15 years, but have some form of 'clawback' of incentive for underperforming systems, as an incentive for installing reliable systems. This approach minimizes the need to finance and provides certain tax and other benefits because the incentive remains performance-based even though offered as a rebate. It is intended to combine desirable features of a PBI and a rebate program and ease administration as well.

smaller than 25 kW that are currently eligible to be qualified for Market Sector A under SREC-II. These include residential systems, and non-residential systems.. The program is split into a Residential Segment and a Non-Residential Segment based on the projected MW distribution among the segments under SREC-II as projected through December 31, 2016.

The EPBI is made up of a series of equal-sized Blocks. Each Block is set as 50% of the allocated segment target. Unlike the DBI under Policy Path A, each Block is defined by EDC-territory-specific Block Prices measured in $/kW (as opposed to $/MWh). The initial Block Price (or offered EPBI) is calculated based on the levelized 15-year incentive payment from the expected production of a benchmark project within each segment. The combination of the offered EPBI and the levelized 15-year typical retail rate payment within the applicable EDC is universal across all EDC territories. All systems within the same segment across all EDC territories will compete for the same Block. The offered Block Price will decline per Block at a fixed rate predetermined based on an economic modeling exercise that accounts for projected annual installed cost decline, set in combination with the Large component of Path A to reach 2500 MW by 2025. Similar to the Policy Path A DBI, a "Safety-Value" feature, which allows for an upward adjustment to the offered solar incentive at the administrator's discretion is included. Again, this feature is not modeled in this analysis.

2.5.1.2 Performance-Based Declining Block Incentive (DBI) Program

The Policy Path B DBI for large installations is structured identically as the Policy Path A DBI for small installations. The available total MWs under this program are divided into four segments in the same proportions as for Policy Path A, as shown in Table 8. It should be noted that under the capped net metering scenario, community-shared solar and low-income housing projects under Sector A are assumed to be unviable once the net metering caps are reached. In this situation, 15% of the MW allocation was shifted from Sector A to the "Other" sector, as discussed further in Appendix A.

As explained in Section 2.4.1.1, each Block is set as 50% of the allocated segment annual target and is defined by $/MWh Block Price. For each segment, the initial combined incentive is set as the levelized 15-year incentive required for a benchmark project. Subsequent declines in the DBI are calibrated to achieve the target 2500 MW by 2025. The initial Block Price is the difference between the combined incentive and the typical retail rate for each EDC, thereby the Block Price is specific to each EDC territory. However, projects from all territories will compete under the same Block.

2.5.2 Net Metering Policy

Policy Path B adopts the same net metering rate structure as it is currently defined. Net excess generation will be credited the current components of retail rate (i.e., generation, transmission, transition, and net distribution as applicable). Virtual net metering customers will receive net metering credits for excess generation after the billing period roll-forward based on the current framework and rates.

3 Technical Factors

The impact of solar PV in reducing the need for generation capacity, as well as the ability to reduce the need for transmission and distribution investment or reduce tariff charges, depends on solar PV's impact on peak demands. The impact of solar PV on various measures of peak contribution, and therefore the ability of solar to avoid such capacity-related investments, is sensitive to the time of system peaks, the production profile of solar PV, and often the quantity of solar PV installed. Likewise, distributed generation located close to load can create a benefit of avoiding energy losses in the transmission and/or distribution system, compared to supplying that same load from distant generators interconnected to and/or shipping electricity over the high voltage transmission system to load. To account for this impact, where applicable, some of the cost and benefit components discussed herein are adjusted to reflect the appropriate level of energy loss avoidance. Each of these overarching technical factors is discussed further in this section.

3.1 Solar PV Impact on Avoiding Generation, Transmission or Distribution Capacity

ISO New England applies a statistical measure of peak contribution – called Claimed Capability - to all generation. Each generator receives a value for Summer Claimed Capability (SCC) for June through September, and for Winter Claimed Capability (WCC) for the other eight months of the year which determines the amount of capacity the generator earns for the ISO's Forward Capacity Market (FCM). For intermittent generation, such as solar PV, the ISO rules grant capability based on the mean production during certain Intermittent Reliability Hours. Solar earns a value during the summer, but during the winter capability period the peak occurs after dark. To the degree that generation sources participate in the FCM they may internalize a monetary value for generation capacity. Because the Intermittent Reliability Hours (discussed in Appendix A) are static (or for so long as they are static), the value that solar PV earns in the FCM is not sensitive to the quantity of solar PV installed.

In contrast, the *actual* impact of solar PV on peak demands for generation capacity (including reserves) depends on the solar fleet's actual ability to impact peak demand.[13] For generation capacity, this impact is a function of the impact in all hours. From the perspective of planning for generation capacity - meeting the Installed Capacity Requirement (ICR) – and for the purpose of planning for transmission and distribution facilities, distributed solar generation's impact on peak demands is driven by the interaction of the applicable load-based drivers and the aggregate production of the distributed solar PV fleet.

The timing of solar PV production is highly coincident with system summer peak hours, but it is not perfectly coincident. Furthermore, since solar PV does not produce the same value in every hour, the capacity impact of added solar PV at different times of day varies. Once solar PV installations become material in magnitude, distribute solar PV can have the impact of shifting the time of peak demand, and at sufficiently large penetrations, adding further solar PV will have no incremental impact on peak reduction.

Figure 2 below illustrates the impact of solar PV at current (2014) penetrations and at 2500 MW (DC) penetration on Massachusetts distribution company aggregate loads for an illustrative summer peak day. As can be seen, with increased penetration the timing of the peak shifts to later in the day. Likewise, Figure 3 below shows the impact of typical peak-day solar PV production on ISO New England peak loads at current (2014) penetrations and at 2500 MW (DC) penetration on the ISO's 2014 peak day. As can be seen, the same quantity of solar PV has somewhat different impacts on peak demands at the state and ISO levels. The illustrative proxy

[13] As shown herein for a sample year, solar has a high coincidence with summer peak demand in Massachusetts and ISO New England, at least at current penetration levels. While a multi-year analysis is beyond the scope of this study, another recent analysis – the 2015 Maine Value of Solar Study (Clean Power Research, LLC; Sustainable Energy Advantage, LLC; Perez Richard; Pace Law School Energy and Climate Center, 2015) looked at a multi-year period and found peak reduction impacts to vary somewhat year to year without altering the basic relationship, so the single year results shown herein should be treated as illustrative.

solar production profile modeled is a representative weighted blend of four solar PV system types (residential roof-mounted, commercial roof-mounted, ground-mounted and canopy) at an indicative location in Worcester,

Figure 2: Illustrative Impact of MA Distributed Solar on MA Distribution Company Peak Day, in 2014 and 2025

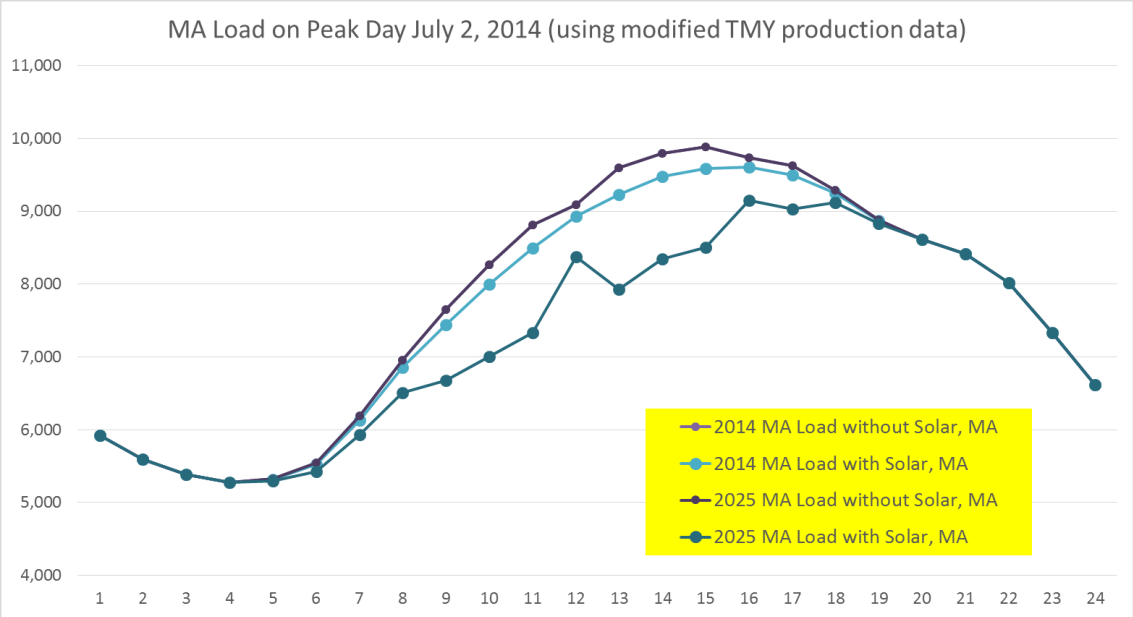
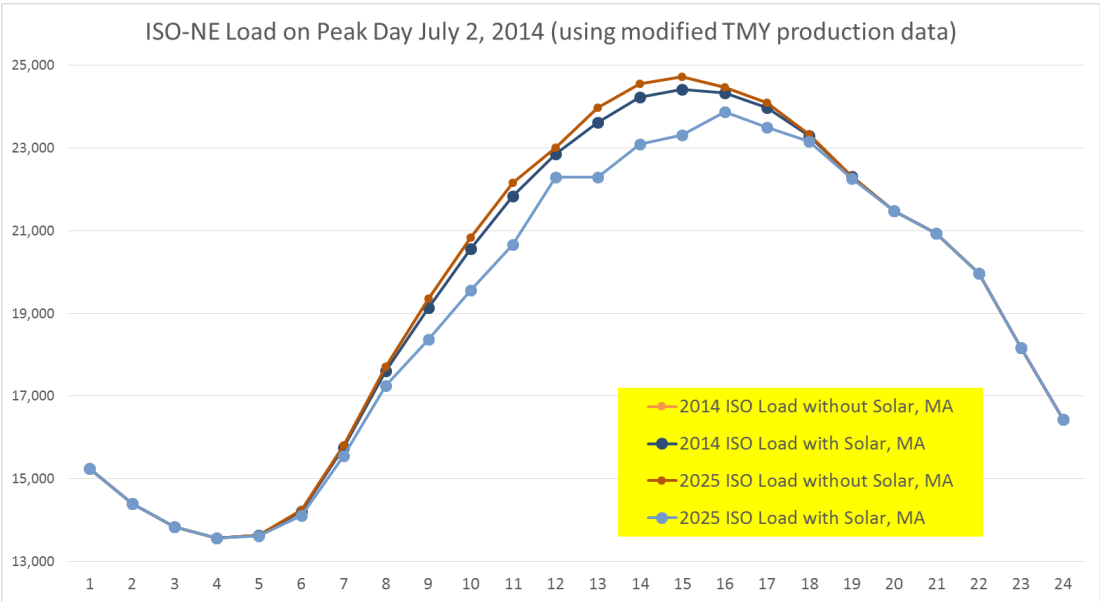


Figure 3: Illustrative Impact of MA Distributed Solar on ISO-NE System Peak Day, in 2014 and 2025



For purposes of this study, the impact of Massachusetts solar PV on the following metrics was calculated:

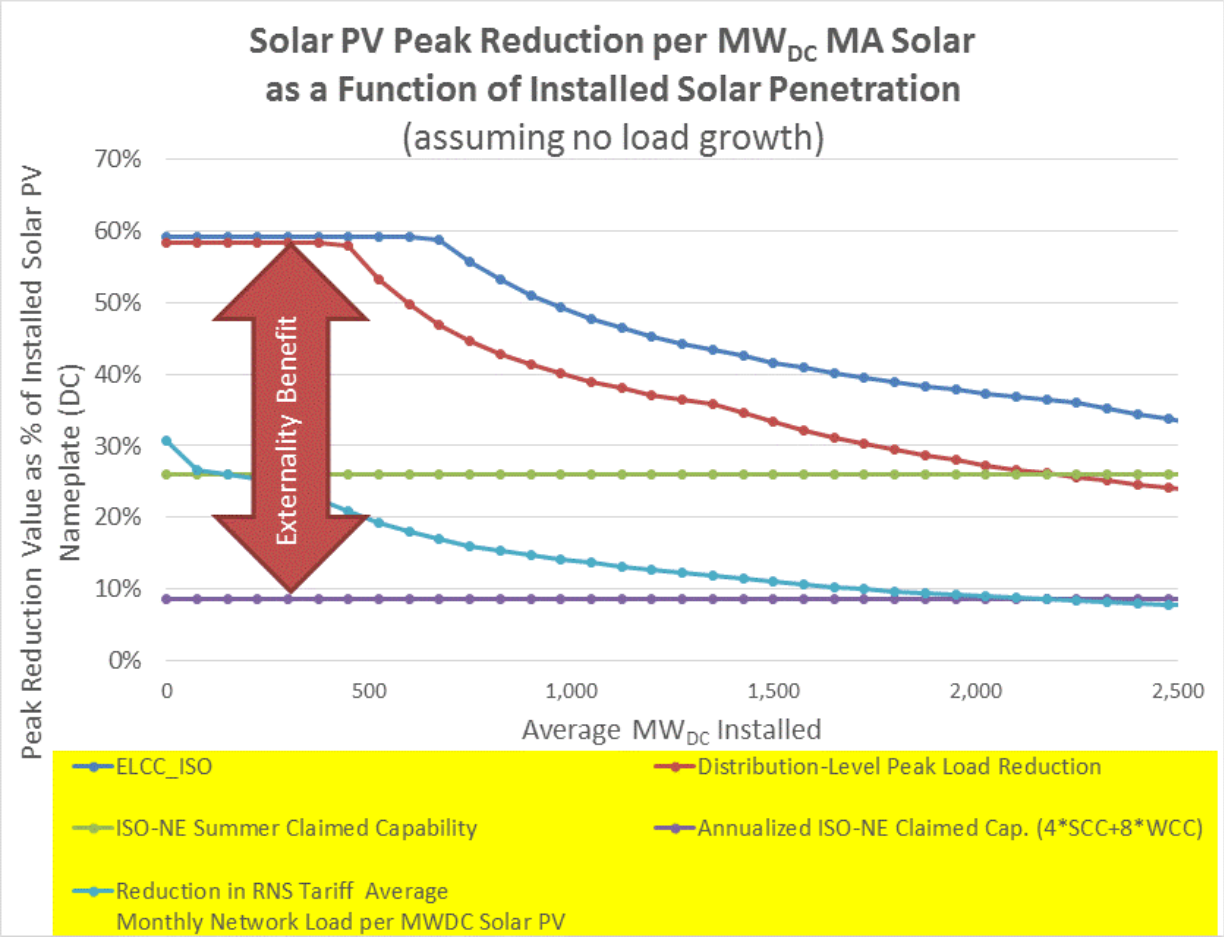
- ELCC_ISO: System generation (i.e. the impact on installed capacity reserves) and transmission peaks
- Massachusetts Distribution-Level Peak Reduction
- The calculated impact on Regional Network Service (RNS) tariff monthly peak loads
- The FCM Summer Claimed Capability (SCC)
- The FCM Weighted Average of Summer and Winter Claimed Capability (where the WCC is zero)

The impact over a range of penetrations from zero to 2500 MW (DC) was examined, to allow for proper attribution of solar PV's peak reduction value at each level of installations over the study horizon. The results are shown in Figure 4. As can be seen, the value of solar in the ISO New England FCM is small (8.7% of DC nameplate for the proxy system) and insensitive to penetration. In contrast, the ELCC-ISO, Distribution Peak and RNS Tariff values decline with increasing solar PV penetration as peaks are shifted over time into later hours. The values are initially high because solar PV has a strong coincidence with the current time of summer peaks. However, it can be inferred from this figure that at much higher penetrations, the peak generation demand would be shifted into nighttime hours with no further impact on peak reduction (an impact of high solar penetration frequently depicted in the now famous "California Duck Diagram")[14].

Generation peak reduction values (the blue line) are somewhat higher than the distribution peak values (the red line), which in turn are higher than the RNS tariff impact. Importantly for the purpose of this study, the FCM values are well below the calculated impacts on reducing system peaks, and this the ICR, until PV penetrations are well in excess of the 2500 MW outer bound used in this study. For the avoided generation value of capacity, the difference (while positive) between actual impact on peak reduction (actual reduction to the ICR) and that quantity monetized in the FCM market by participating solar PV facilities represents an externality benefit of reduced generation capacity costs to all citizens of Massachusetts.

[14] California Independent System Operator, Demand Response and Energy Efficiency Roadmap: Maximizing Preferred Resources, December 2013. http://www.caiso.com/Documents/DR-EERoadmap.pdf

Figure 4: MA Solar PV Peak Reduction Metrics per MW Installed, as a Function of MW Installed PV



To account for expected values of solar PV impacts at various penetrations, the factors summarized in Figure 4 are applied in calculating applicable cost and benefit components.

3.2 Avoided Loss Factors

For some of the cost and benefit components in this study, solar PV at the distribution level has the impact of avoiding energy losses in the transmission and/or distribution system that would otherwise be experienced in moving distant generation injected onto the regional transmission grid to load in Massachusetts. Losses are higher at peak times than off-peak times, as losses are a function of the square of the current flowing over a circuit. Using the average and peak loss factors provided by some of the Massachusetts EDCs (see Appendix A), average statewide energy losses were calculated in every hour[15], and this data was in turn used to estimate statewide average solar PV production-weighted energy losses. The loss factors used in this study are shown in Table 9. The average and peak loss data by utility used to calculate these statewide loss factors is found in Appendix A.

[15] Using a best-fit square function aligning with average hourly and peak values.

Table 9: Statewide Weighted Average MA DG Solar Avoided Electric Loss Factors

Loss Level	Loss Factor
MA Avg. Peak T&D	8.62%
MA Avg. Peak D	7.34%
MA Avg. Production-Wtd Energy T&D	5.58%
MA Avg. Production-Wtd Energy D	4.72%

Where applicable, to account for the expected impact on reduction of losses of solar PV, an appropriate peak or production-weighted energy loss adjustment factor is applied in calculating costs or benefit components.

4 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.

4.1 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:

4.1.1 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.

4.1.2 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.~~

4.1.3 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 10: 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.

- Parametric 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 11: Key to Cost and Benefit Description Tables

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

4.2 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

Refer to Appendix Components of Cost/Benefit Analysis for a detailed description of each subcategory.

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

Table 12: 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 MA Income Taxes ROI to Lenders/Investors	Federal Income Taxes

4.3 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

Refer to Appendix Components of Cost/Benefit Analysis for a detailed description of each subcategory. 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 13: 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

4.4 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

Refer to Appendix Components of Cost/Benefit Analysis for a detailed description of each subcategory. 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 14: 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		

4.5 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*

Refer to Appendix Components of Cost/Benefit Analysis for a detailed description of each subcategory. 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 15: 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		

4.6 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

Refer to Appendix Components of Cost/Benefit Analysis for a detailed description of each subcategory. 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 16: 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		

4.7 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*

Refer to Appendix Components of Cost/Benefit Analysis for a detailed description of each subcategory. 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 17: 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	• N/A

	• Avoided Distribution Investment • Avoided Natural Gas Pipeline Investment [1]	
[1] Explored qualitatively		

4.8 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*

Refer to Appendix Components of Cost/Benefit Analysis for a detailed description of each subcategory. 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 18: 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		

5 Projected Solar PV Build-out under Each Scenario

In this Section, the projected solar PV build-out trajectories are presented, including (i) the incremental MW_{DC} installation by program under each policy path, as well as (ii) the build-out under each scenario by SREC-II project type subsector, demonstrating that different policy choices lead to notably different build-out results.

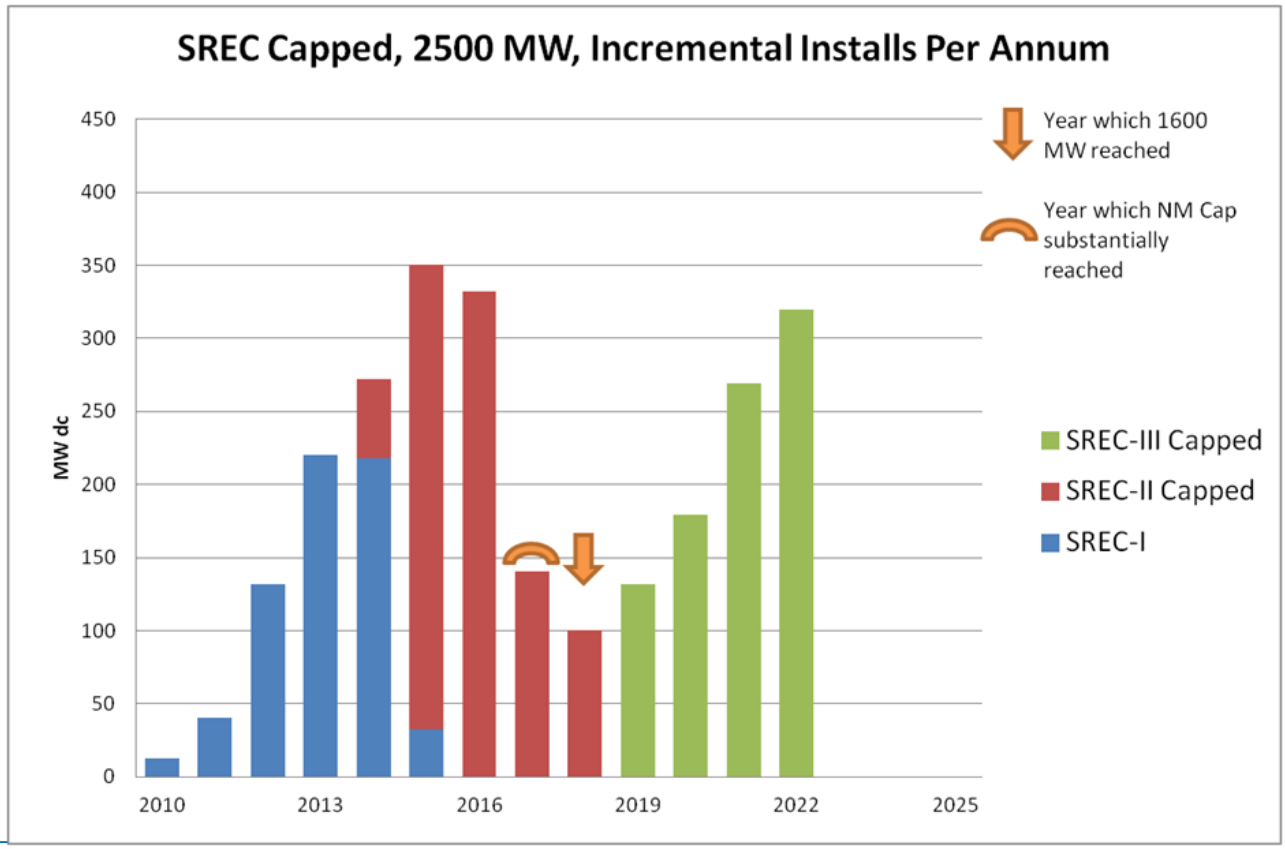
5.1 Comparing Solar Build-out Trajectories

5.1.1 SREC Policy Future – Capped

With current net metering caps, the SREC-II market is projected to experience a burst of activity implementing projects under the project cap and before the step-down of the Federal ITC, allowing almost 1350 MW of the 1600 MW target to be reached by the end of 2016 and the full 1600 MW filled by the end of 2018. It is important to note that, due to several simplifying assumptions (described in Part A of Appendix A, Key Assumptions), the modeled build rate may be moderately faster than likely to be experienced.

In the SREC capped policy future, 2500 MW are installed by 2022 with four years of the SREC-III program installations after reaching 1600 MW in 2018. Net metering caps are substantially reached in 2017 and annual installs never reach 2015 and 2016 annual installation rates thereafter. As can be seen in Figure 5, despite modeling SREC-III using annual MW targets from the DOER's compliance obligation formula designed to smoothly reach 2500 MW by 2025 with a modestly inclining annual build rate from the annual build rate in the last year of SREC-II (2018), the projected economics of projects – all in market segments in which quantities are not 'managed' – outstrip the targets to reach 2500 MW by 2022.

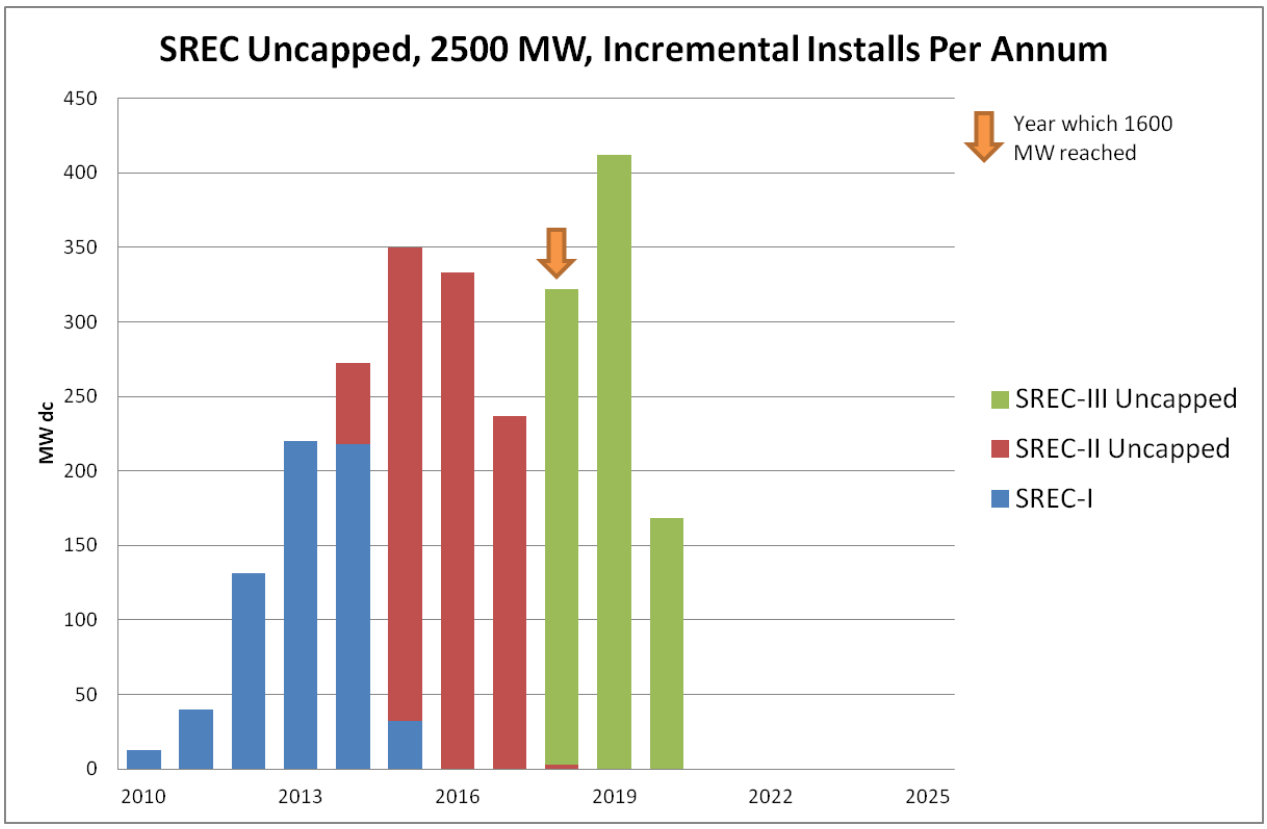
Figure 5: SREC Capped to 2500 MW Incremental Installations per Year by Program



5.1.2 SREC Policy Future – Uncapped

In a future without net metering caps, modeling of the SREC-II market results in a greater acceleration of build-out and hitting 1600 MW in the first quarter of 2018. This growth is driven by the combined economics of the solar policy incentive and net metering values, and overcomes ITC cliff.. Again, despite modeling SREC-III using annual MW targets designed to smoothly reach 2500 MW by 2025 with a modestly inclining annual build rate the economics of SREC-III in an uncapped environment overtake the annual targets and result in the 2500 MW goal being reached in Q1 2020 after only eight quarters of SREC-III. Net metering caps are not applicable in the uncapped policy future which allows annual installations to rebound to pre-ITC cliff build rates after a slight drop in 2017 The rebound is so strong over 400 MW are projected to be installed in 2019 (see Figure 6).

Figure 6: SREC Uncapped to 2500 MW Incremental Installations per Year by Program

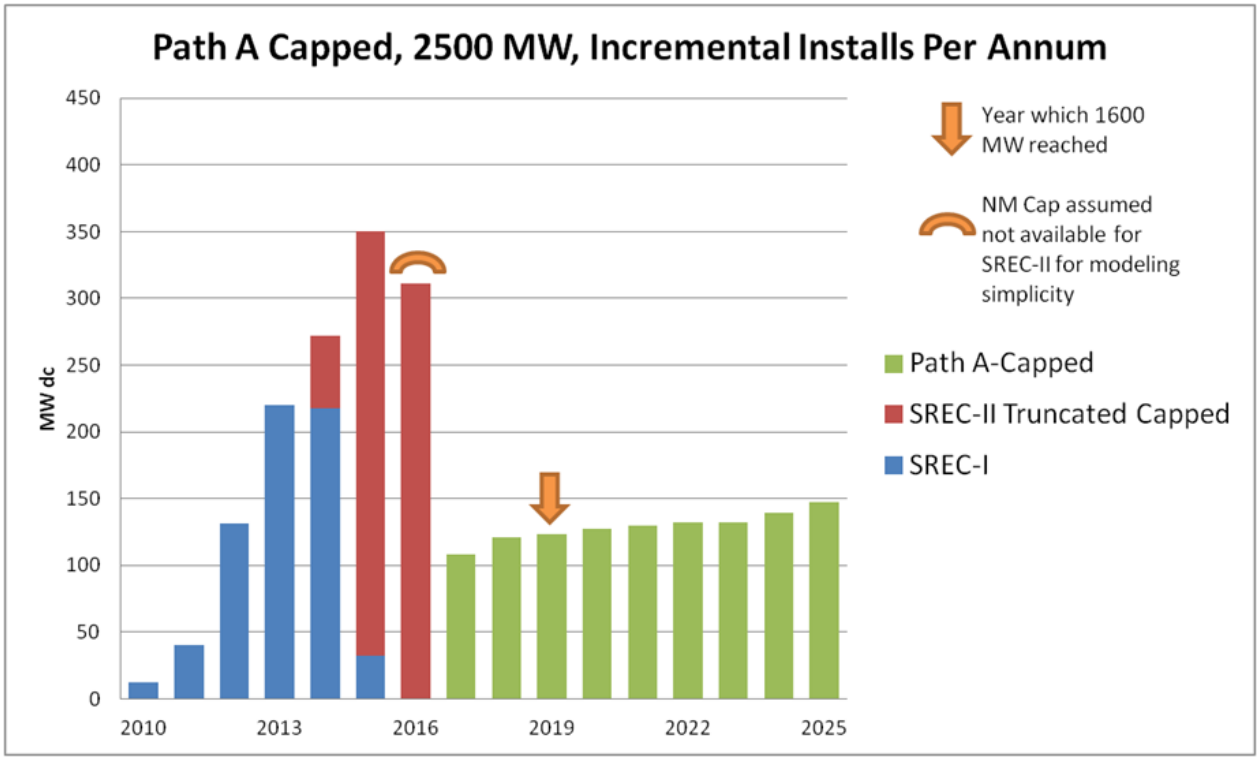


As noted earlier, the SREC policy continued to 2500 MW is not modeled further for benefits and costs, as it reaches 2500 MW so quickly as to not provide a useful point of comparison to other policy futures, and because it led to a number of other complicating factors from a modeling perspective.

5.1.3 Policy Path A – Capped

In the Policy A capped policy future, SREC-II is truncated after Q4 2016, after which net metering caps are assumed to not be available for modeling simplicity[16]. Cumulative installed totals reach 1600 MW in 2019. Annual incremental installations incline steadily until the 2500 MW goal is reached in 2025. The competitive solicitation approach for large installations under Path A substantially controls the pace of installation to provide for a stable and slightly growing annual build rate after the initial contraction required to spread almost 1200 MW of installations over nine years (see Figure 7).

Figure 7: Policy A Capped to 2500 MW Incremental Installations per Year by Program

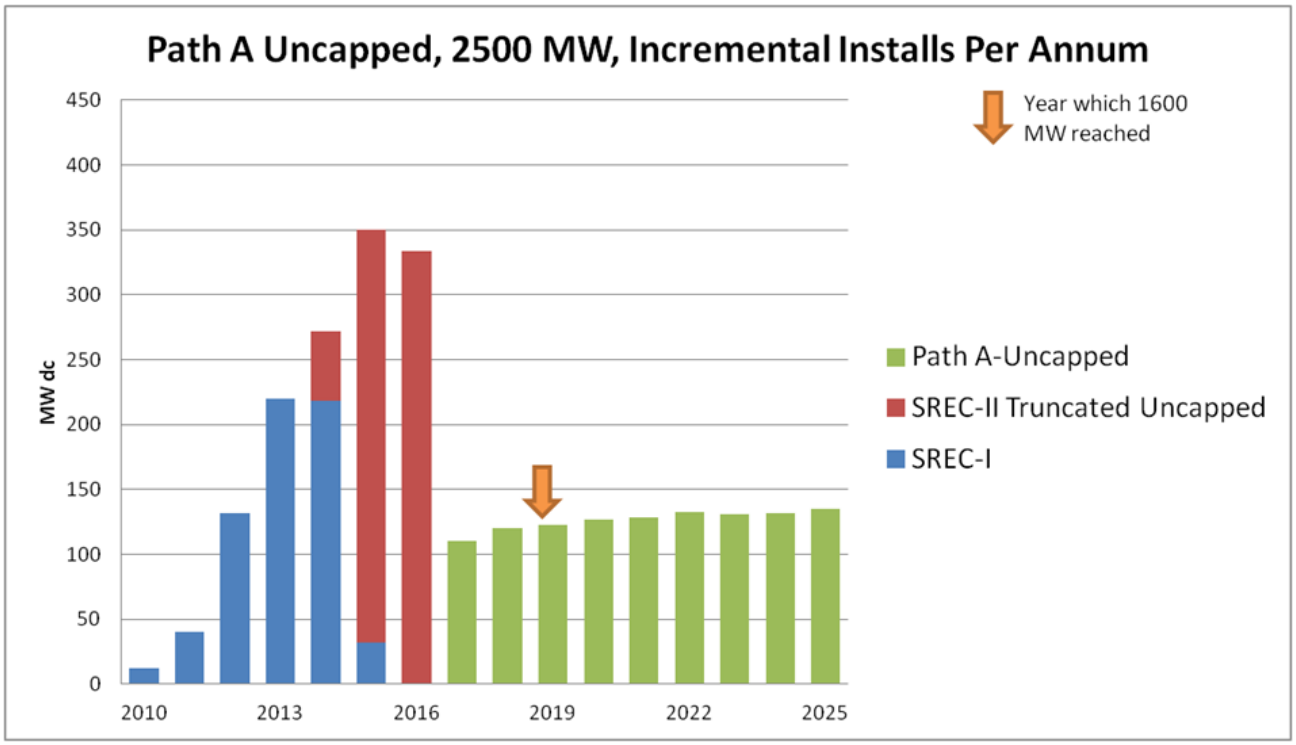


5.1.4 Policy Path A – Uncapped

Under the Policy A uncapped policy future, SREC-II is truncated after Q4 2016, at which point about 700 MW were installed under SREC-II, about 40 MW more than in the capped scenario. 1600 MW is reached in 2019, the same year as in the Policy A capped scenario though the uncapped scenario hits 1600 MW very early in 2019, while the capped scenario hits 1600 MW in mid-2019. This is a function of the engineered growth rate to meet 2500 MW in 2025 which means overall slightly lower annual incremental installations in the uncapped scenario.

[16] After 2016 there is about 30 MW of net metering cap space available that is ignored for modeling simplification, which does not materially impact the results.

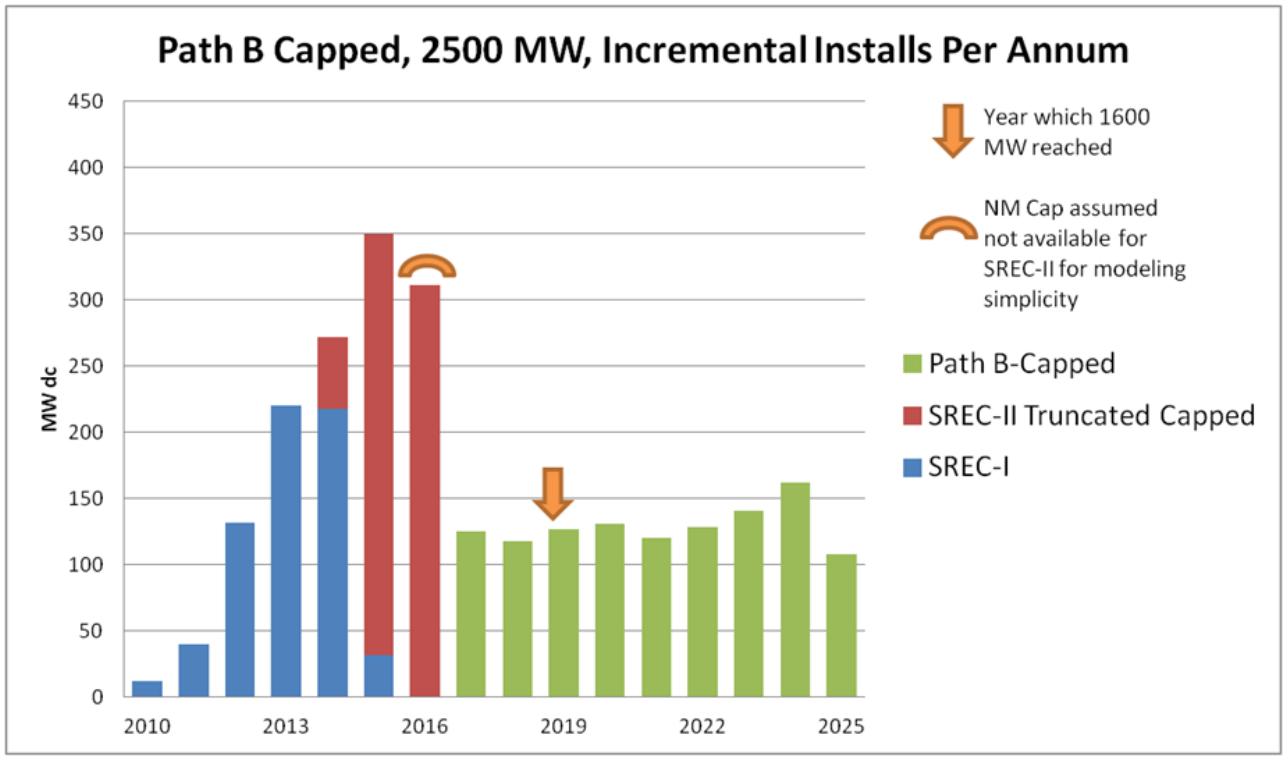
Figure 8: Policy A Uncapped to 2500 MW Incremental Installations per Year by Program



5.1.5 Policy Path B – Capped

Under the Policy Path B capped scenario future, SREC-II is truncated after Q4 2016, after which net metering is assumed to be no longer available for> 25 kW projects for modeling simplicity. 1600 MW is reached in 2019 and 2500 MW is reached in Q2 2025. Incremental annual installations after 2016 are fairly consistent because of modeled optimization of incentive levels and DBI annual decline rates, yet are more volatile in Policy B than Policy A because of the incentive structure. This difference is covered in more detail later in this section.

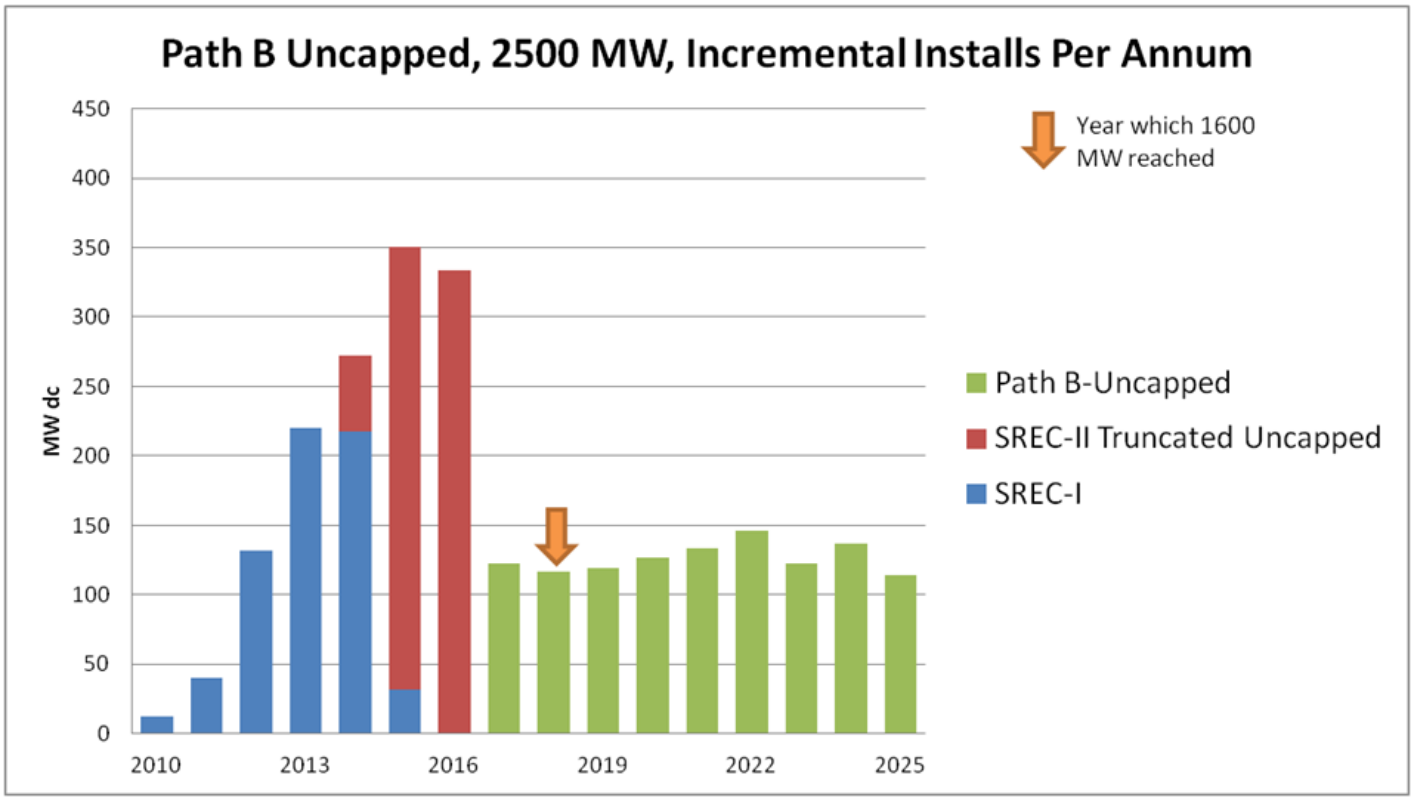
Figure 9: Policy B Capped to 2500 MW Incremental Installations per Year by Program



5.1.6 Policy Path B – Uncapped

Under the Policy Path B uncapped scenario future, SREC-II is truncated after Q4 2016. 1600 MW is reached in 2019 and 2500 MW is reached in Q2 2025. As under the capped scenario, the buildout rate is somewhat more volatile than under Path A.

Figure 10: Policy B Uncapped to 2500 MW Incremental Installations per Year by Program

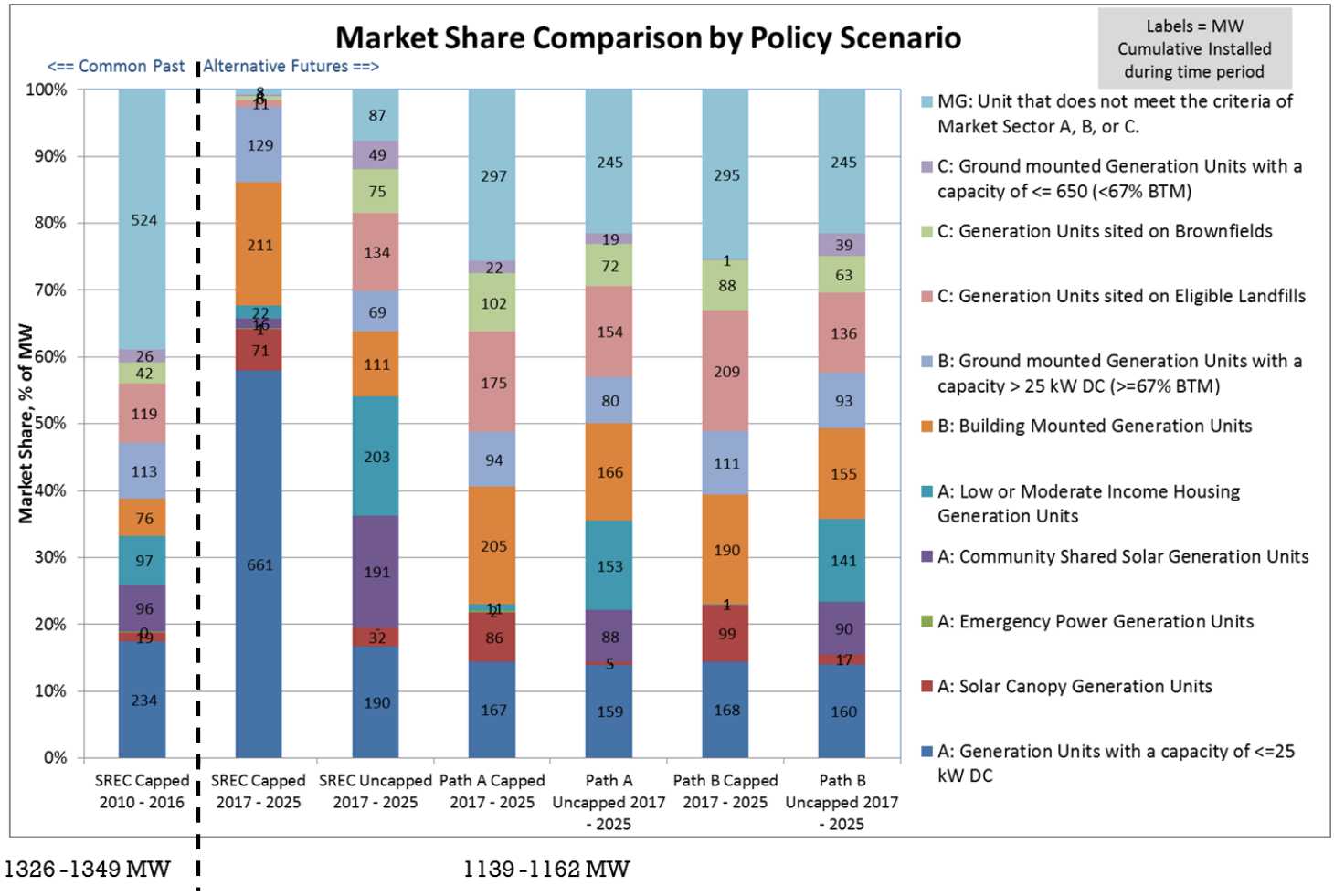


5.2 Solar Build-Out Market Share Projections by SREC-II Market Sector

In this Section, the projected solar PV build-out trajectories are presented by SREC-II Market Subsector, including (i) subsector market share MW_{DC} installation and percentage of cumulative installations under each policy scenario, as well as (ii) incremental MW_{DC} installations per year under each policy scenario, and (iii) a comparison of the MW_{DC} cumulative installed by market subsector and percent installed under each policy scenario before 2016 and after to 2025.

As shown in Figure 11, the cumulative installations of the common past of all policy futures is made up of almost 40% Managed Growth installations. No other policy future builds close to this amount of managed growth. In the common past through 2016, about 14% of total build-out is expected to come from a near-term boom in construction of larger ground-mounted projects in the Community Shared Solar (CSS) and virtual net metering Low-Income Housing (VNM LIH) subsectors, two market segments heavily or entirely dependent on the mechanics of virtual net metering for their existence. Almost 20% of the cumulative installs through the end of 2016 are projected to come from the <= 25 kW subsector. In getting to 2500 MW, this proportion declines slightly in all policy futures except SREC capped, which builds almost three times the cumulative installations in the subsector seen in SREC capped to 2016. In all policy futures cumulative installations in the Building Mounted subsector increase. The net metering policy clearly drives the cumulative installations of VNM LIH and CSS since in capped scenarios neither of these project subsectors will have projects installed (with the exception of a small sliver of small on-site rooftop affordable housing projects).

Figure 11: SREC-II Subsector Market Share Comparison by Policy Scenario



In the following subsections, the evolution of subsector market share is depicted under each policy scenario. As can be seen, the evolution of the market under these different futures can spell material changes for specific market sectors.

5.2.1 SREC Policy Future – Capped

Under the SREC capped policy future, there is a sharp decline in incremental annual installations in 2017 after net metering caps are reached for public NM bucket and the ITC expires. After net metering caps are reached, the majority of SREC-II installations are in the <= 25 kW and Building Mounted subsectors. Figure 13: SREC Capped Subsector Market Share Comparison Before and After 2017Figure 13 shows that <= 25 kW installations make up almost 60% of cumulative installs after 2016. While this change appears dramatic, as can be seen it requires a sustained annual increase in annual build rates, but at a rate that is not dramatically above the rate of increase for those sectors in some past years. While economics dictate this market shift, it likely strains the ability of the subsector to maintain such a sharp and steady growth rate. It also presages a domination of the future market by installations with the highest average installed cost, leading to the slightly counterintuitive result that a capped future could have a higher total cost than an uncapped future with a lower average per Watt installed cost.

Figure 12: SREC Capped to 2500 MW Incremental Installations per Year

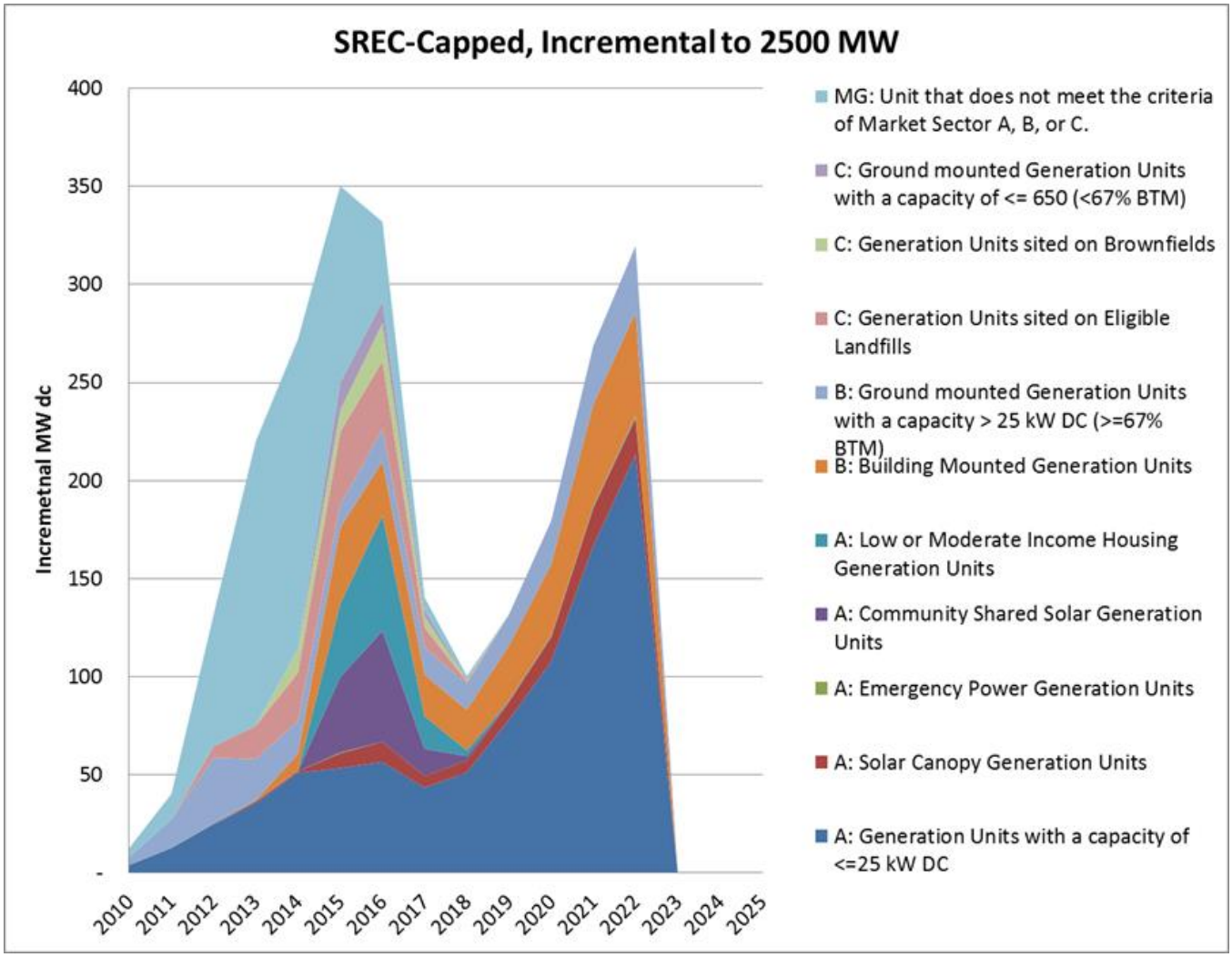


Figure 13: SREC Capped Subsector Market Share Comparison Before and After 2017

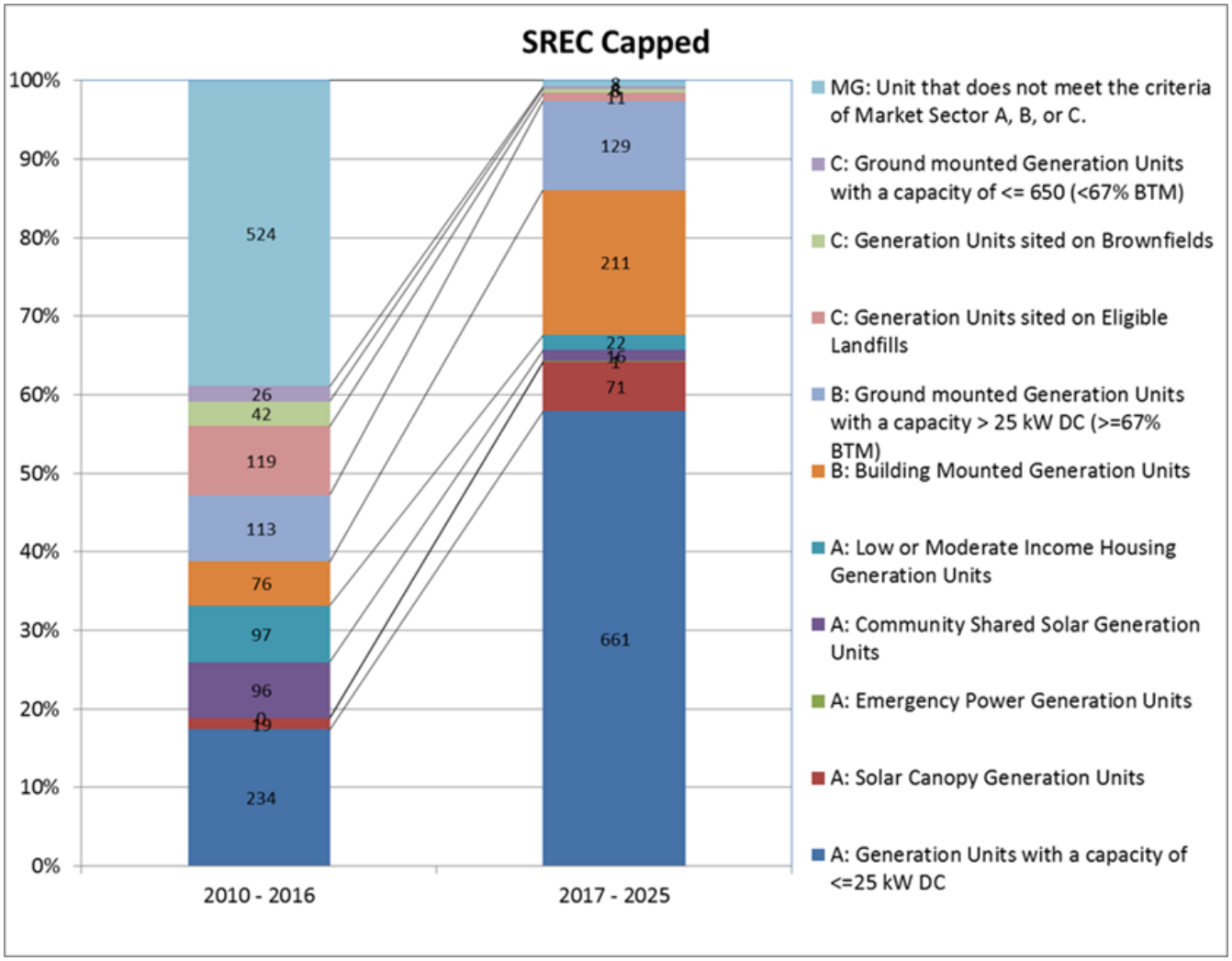


Figure 13 underscores that the dramatic market share growth in small and Building Mounted subsectors comes at the expense of MG projects, CSS, VNM LIH, landfill, brownfield and other ground-mounted systems who lose the ability of net metering.

5.2.2 SREC Policy Future – Uncapped

As can be seen in Figure 14, under the SREC uncapped policy future, there is a slight decline in annual incremental installations in 2017 after ITC expires for most project types. With no net metering caps, Community Shared Solar (CSS) and virtually net metered low-income housing (VNM LIH) together make up over 30% of the cumulative installed capacity after 2016. This trend contributes to the 2500 MW target being met rapidly in 2020. Figure 15 shows that the market subsector composition remains relatively the same after 2017 except for having less managed growth. Managed growth installations are replaced by CSS and VNM LIH as well as more landfill and brownfield projects.

Figure 14: SREC Uncapped to 2500 MW Incremental Installations per Year

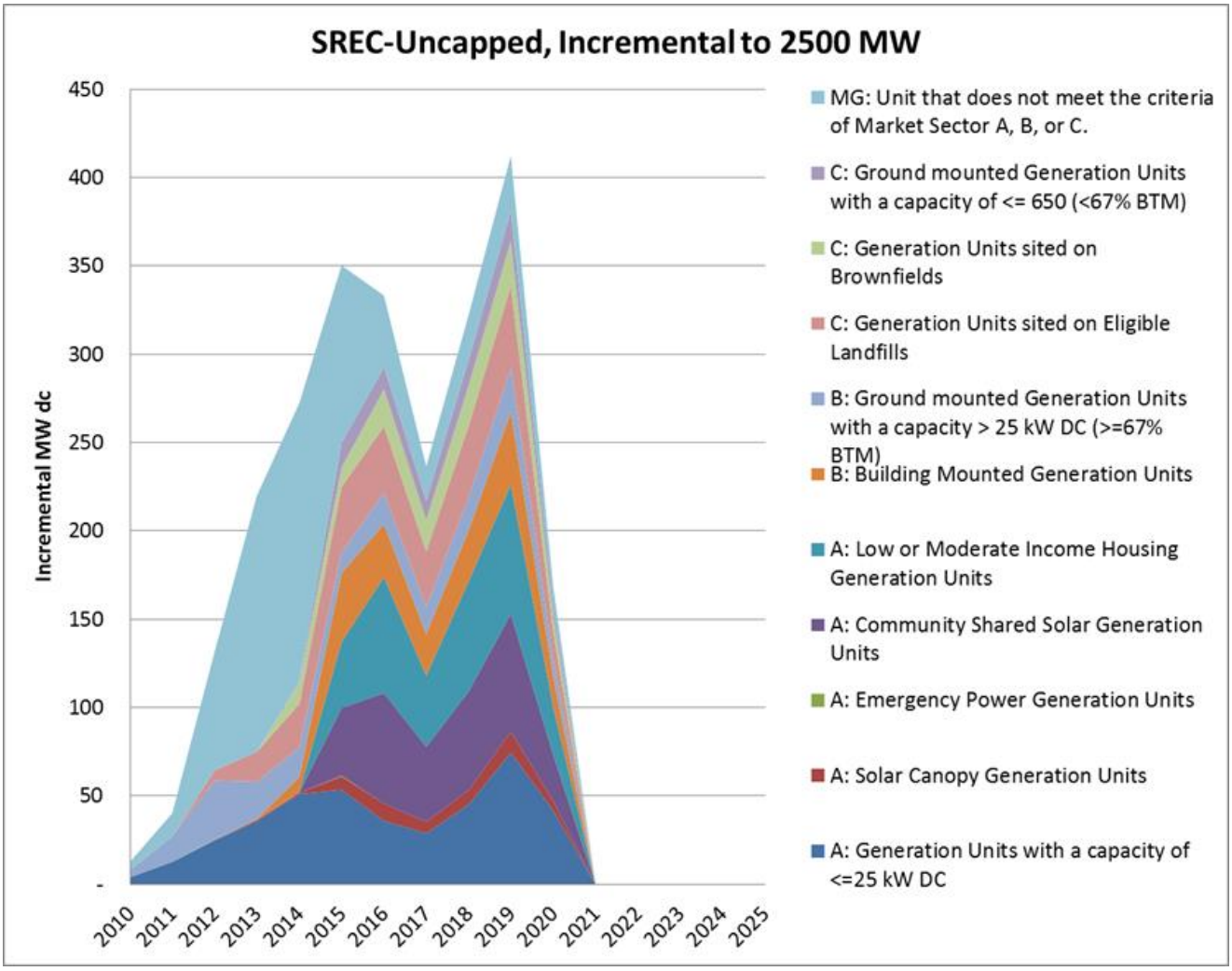
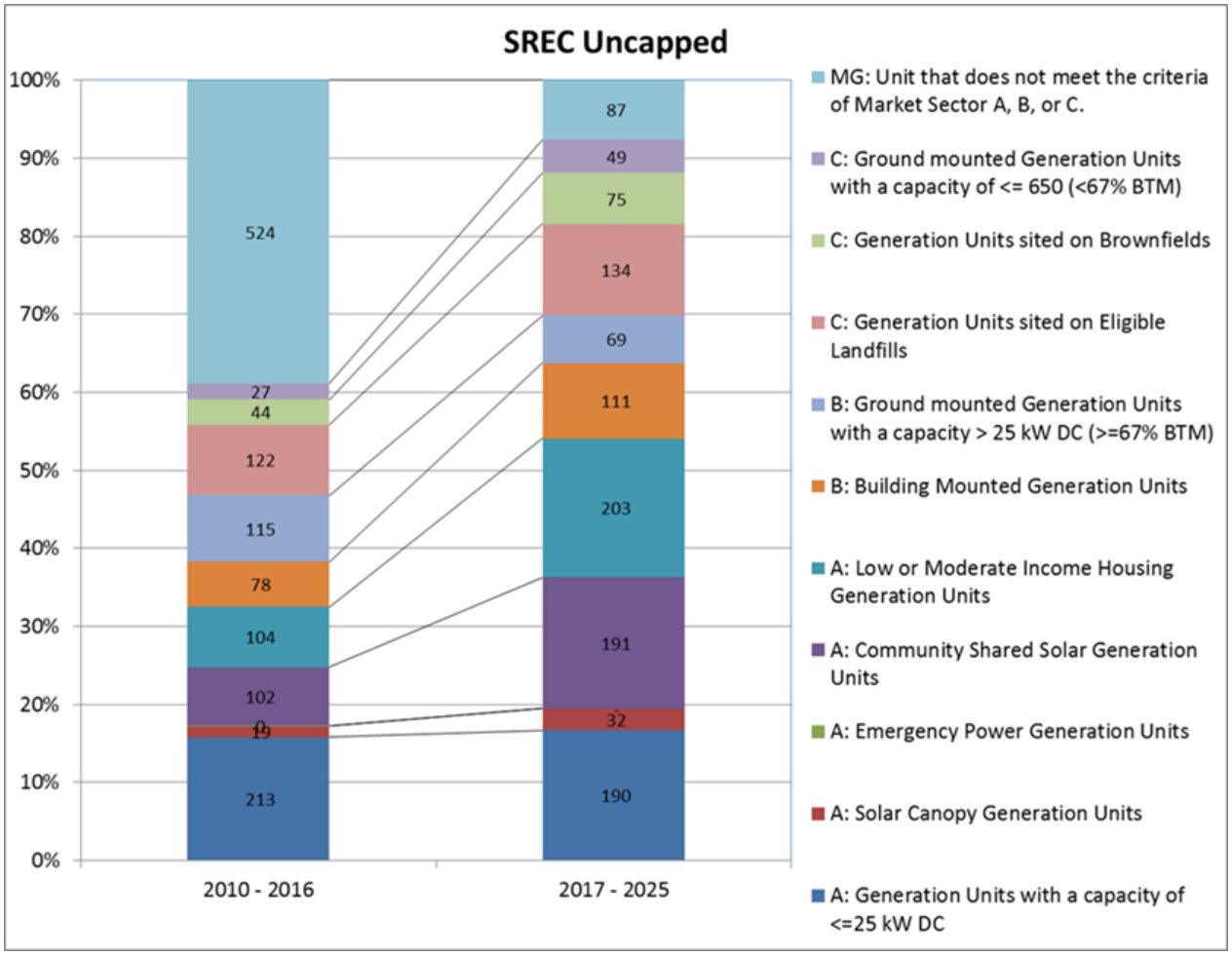


Figure 15: SREC Uncapped Subsector Market Share Comparison Before and After 2017



5.2.3 Policy Path A – Capped

As shown in Figure 16, under the Policy Path A capped policy future, there is a steep drop off in incremental annual installations after SREC-II is truncated after Q4 2016. The more moderate growth after 2017 is a result of the engineered growth rate in Policy A necessary to meet the 2500 MW goal in 2025. The largest difference between Policy A capped and SREC capped is that Managed Growth projects continue to be built under Policy A, whereas additional MG projects are not needed under the SREC-III policy i.[17] In this scenario, CSS and VNM LIH are not feasible without net metering. Landfills, brownfields, and Managed Growth projects fill this gap since they are feasible with a combined incentive even when relying on wholesale market prices. As in other capped policy

[17] Note: while SREC-III does not require additional MG projects to reach 2500 MW, the way in which Policy A (and Policy B) are being modeled is that each Sector is assigned a 25% share of the MW goal to reach 2500 MW (after assigning a portion of the share to small projects). So while Policy Paths A & B might not need MG to reach 2500 MW the MG sector gets to participate regardless.

scenarios, with the loss of net metering, there is an increase in on-site load dependent projects like Building Mounted and Solar Canopy.

Figure 16: Policy A Capped to 2500 MW Incremental Installations per Year

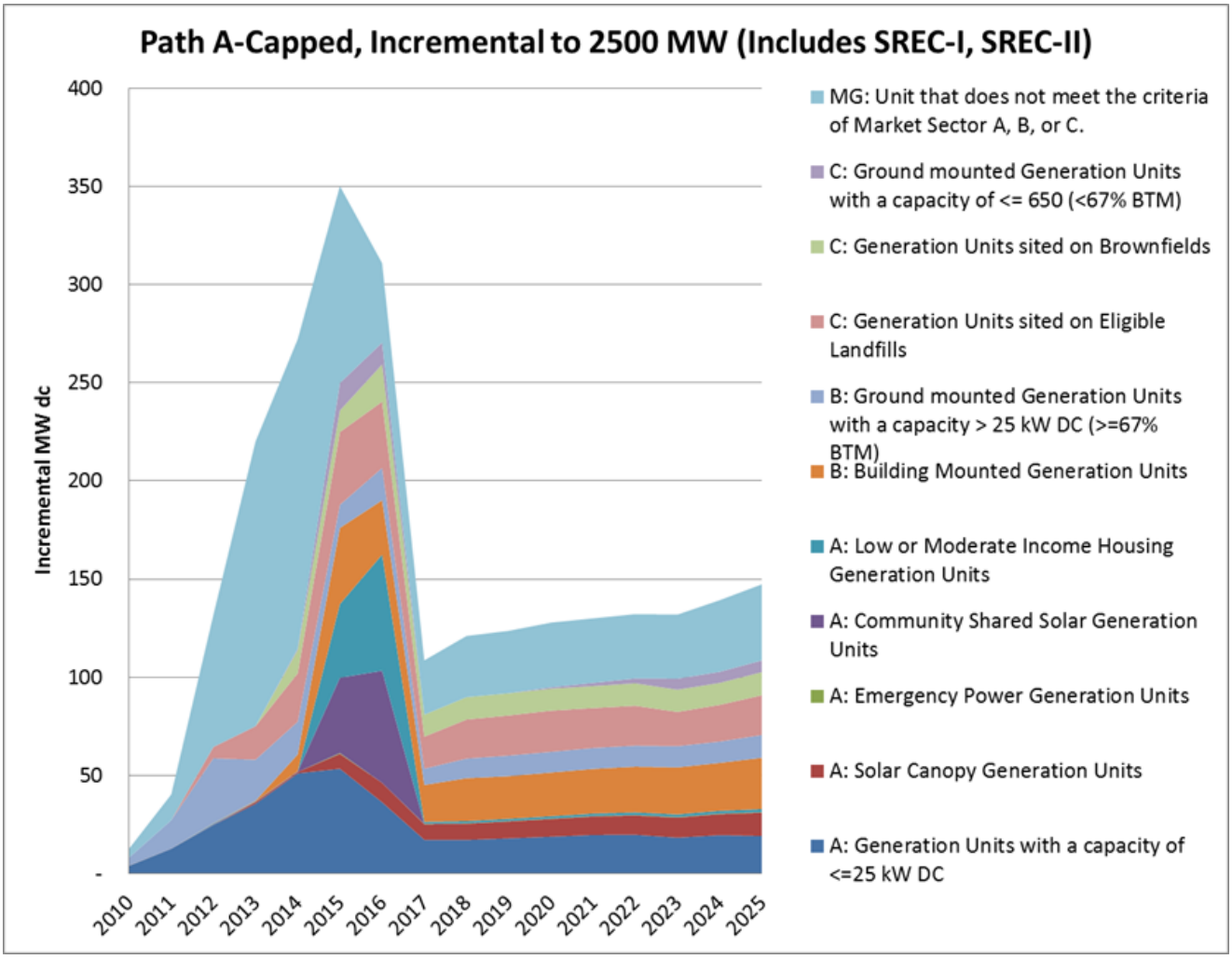
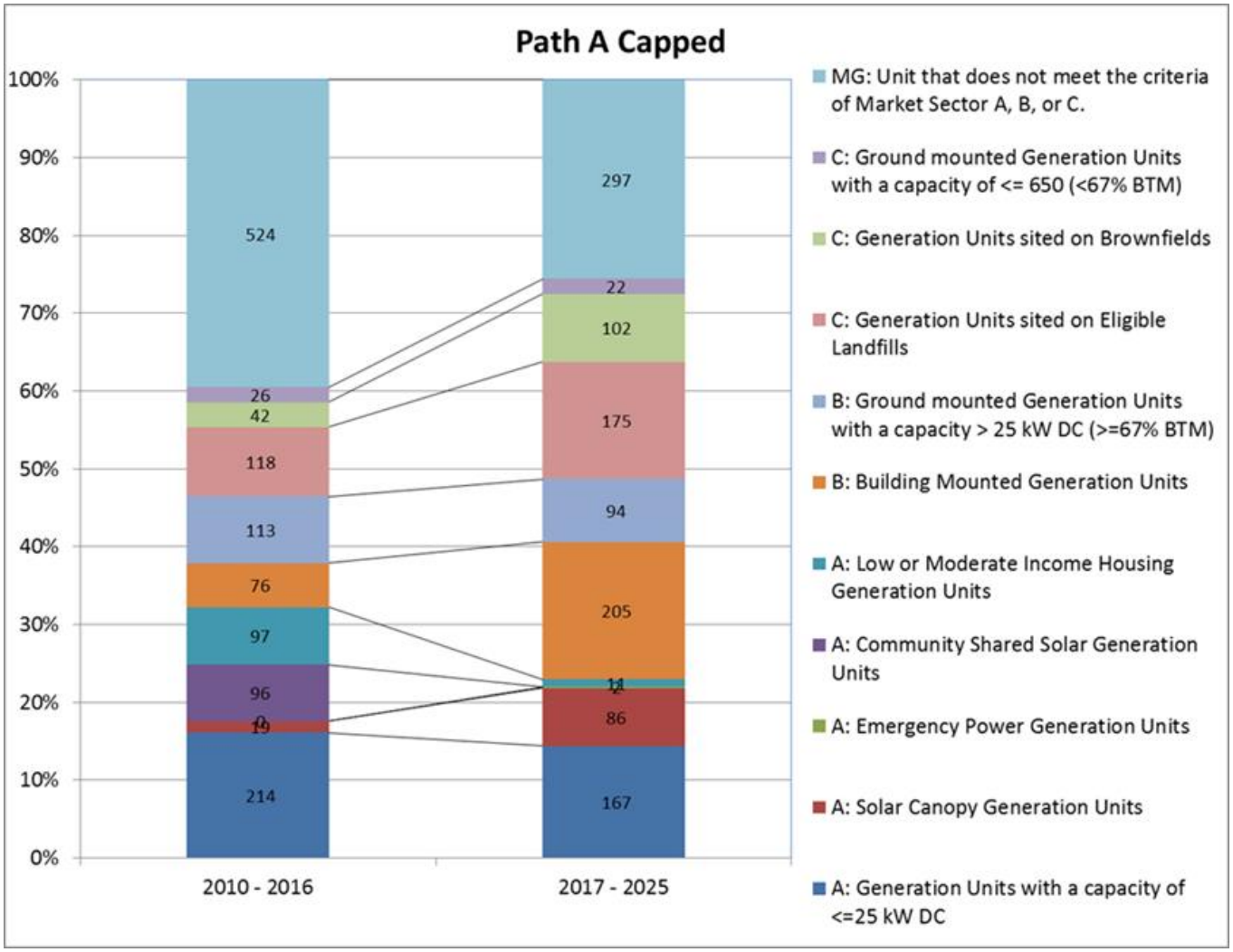


Figure 17: Policy A Capped Subsector Market Share Comparison Before and After 2017



5.2.4 Policy Path A – Uncapped

Under the Policy A uncapped future, Figure 18 shows that there is a similar project mix to the SREC uncapped policy future except for Managed Growth being built in Policy A. Again the engineered growth via quotas in the bid system cause a drop off after SREC-II is truncated in order to meet the 2500 MW goal in 2025. Under this policy future, Managed Growth cumulative installations decline and brownfield, landfills, Building Mounted, CSS and VNM LIH subsectors make up the difference. <= 25 kW subsector cumulative installations decline.

Figure 18: Policy A Uncapped to 2500 MW Incremental Installations per Year

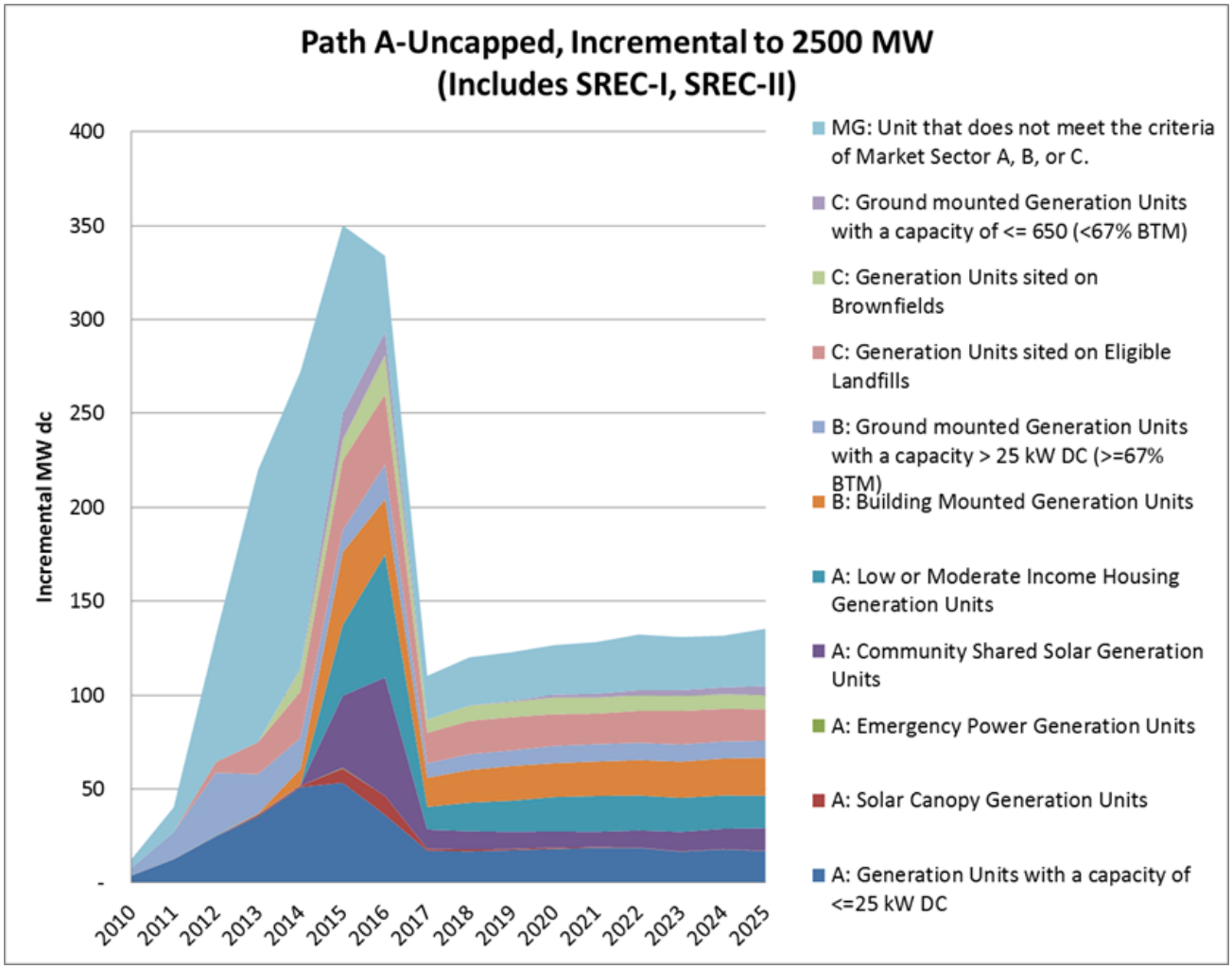
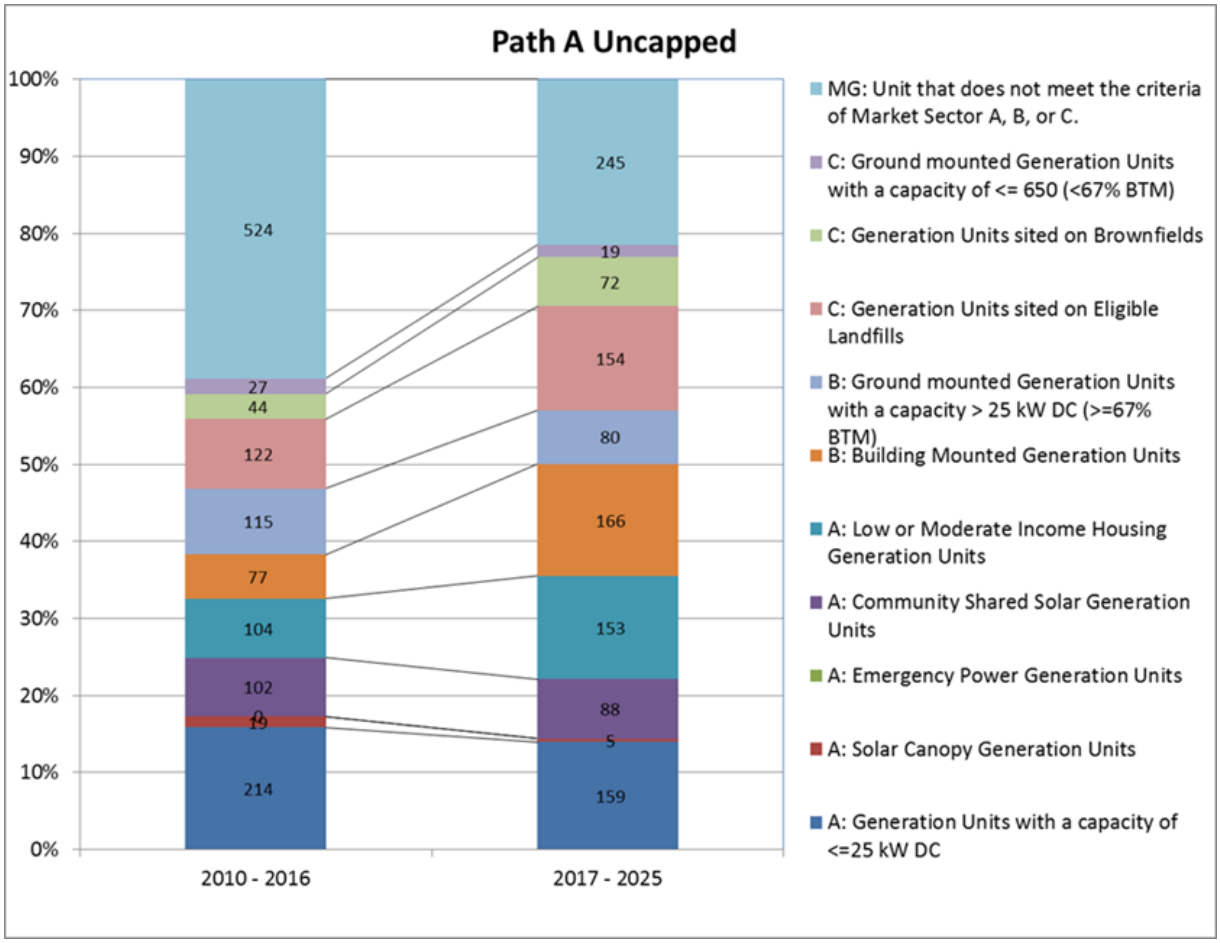


Figure 19: Policy A Uncapped Subsector Market Share Comparison Before and After 2017



5.2.5 Policy Path B – Capped

As shown in Figure 20, under the Policy B capped future there is a similar build-out shape to Policy A aside from the incremental installation variability seen after 2017, as well as the project mix. CSS and VNM LIH are not installed after 2016 since there is no net metering. Managed Growth, landfill, and brownfield subsector projects are built instead and are feasible with wholesale rates because of the Policy B combined incentive structure. Towards the end of Policy B program, the growth rates increase since there is no additional incentive needed beyond the retail rates (for sized to load projects) or wholesale rates (for large ground mount projects). In Policy B there is a higher potential for volatility than in Policy A since Policy Path A guarantees a specific amount for 85% of targets for all but small. While installation rates in Policy B could be made flat with perfect foresight, in the real world the declining block incentive has the potential to create material volatility if the rate of incentive decline tracks faster or slower than the rate of cost of entry evolution.

Figure 20: Policy B Capped to 2500 MW Incremental Installations per Year

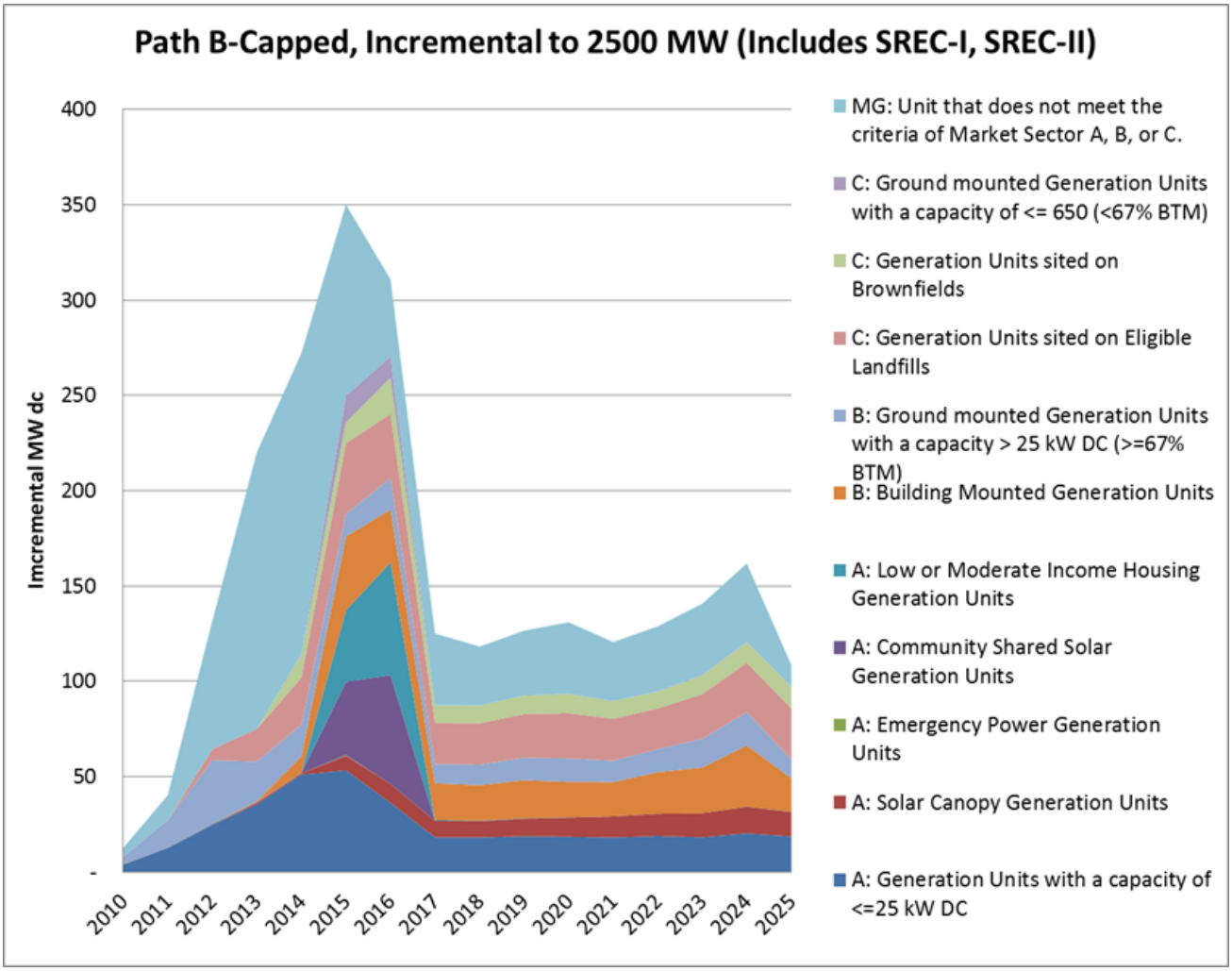
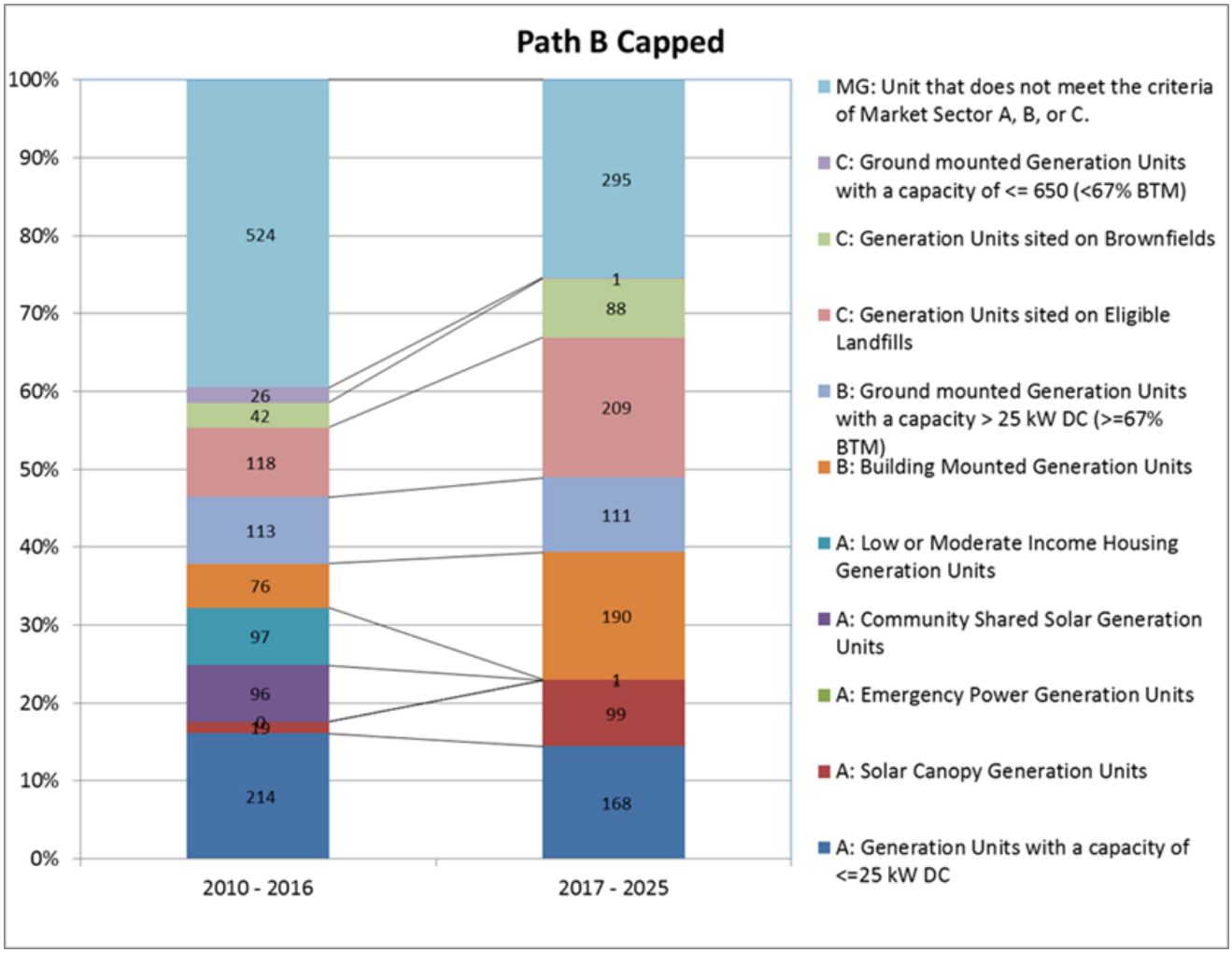


Figure 21: Policy B Capped Subsector Market Share Comparison Before and After 2017



5.2.6 Policy Path B – Uncapped

Under the Policy B uncapped future, the overall build-out rate looks similar to those of Policy B capped because of the engineered growth rate after 2017. As in Policy B capped, the spike in installations after 2023 is a function of a zero incentive requirement, completely driven by net metering rates revenue which by then is sufficient revenue to support many installation types. There is a faux decline in 2025 since targets are met in Q2 2025. Installs could actually grow at an accelerated rate in this year unless the program qualification somehow serves as a 'gate-keeper' for market entry. Figure 23 shows that VNM LIH and CSS cumulative installations increase after SREC-II is truncated.

Figure 22: Policy B Uncapped to 2500 MW Incremental Installations per Year

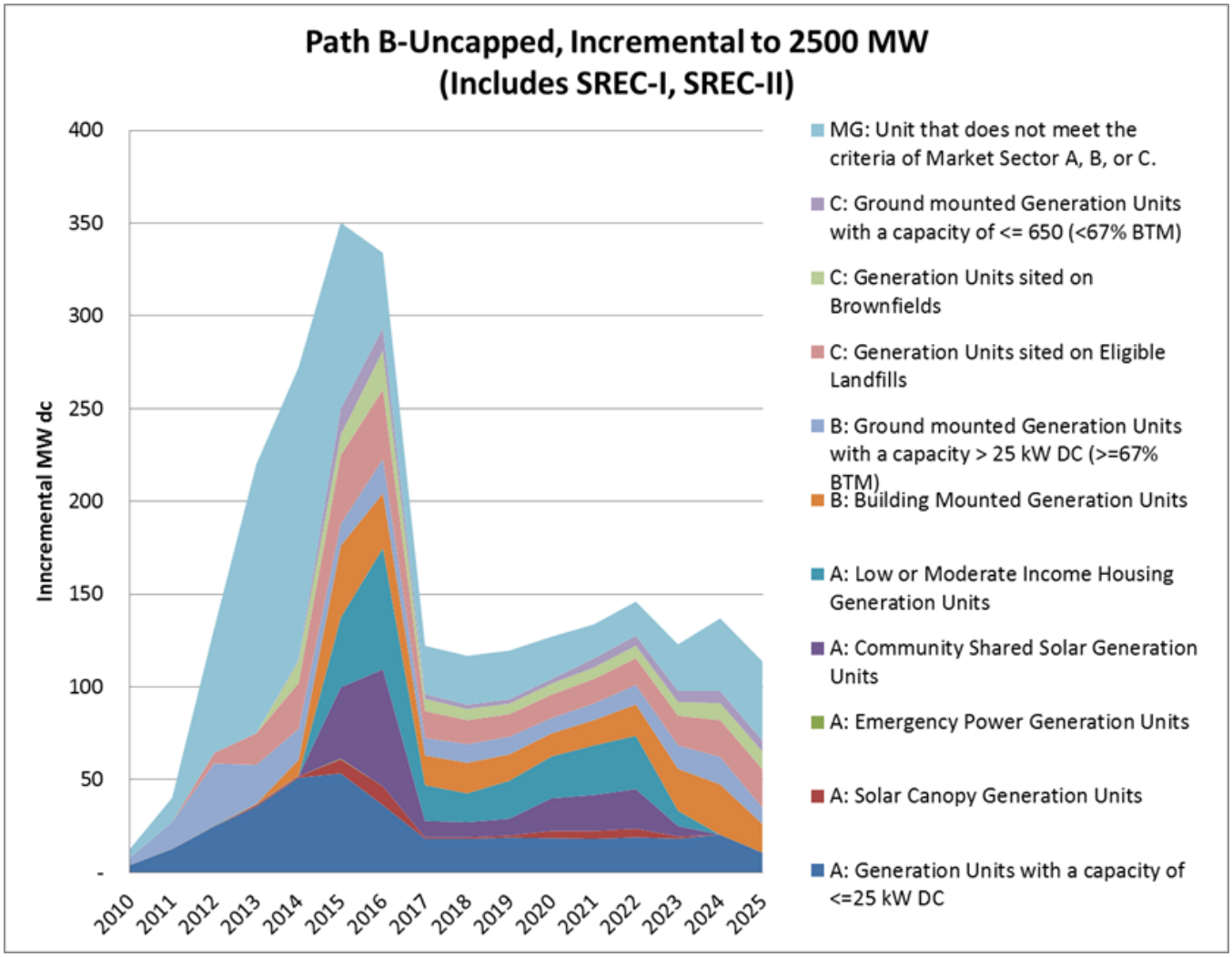
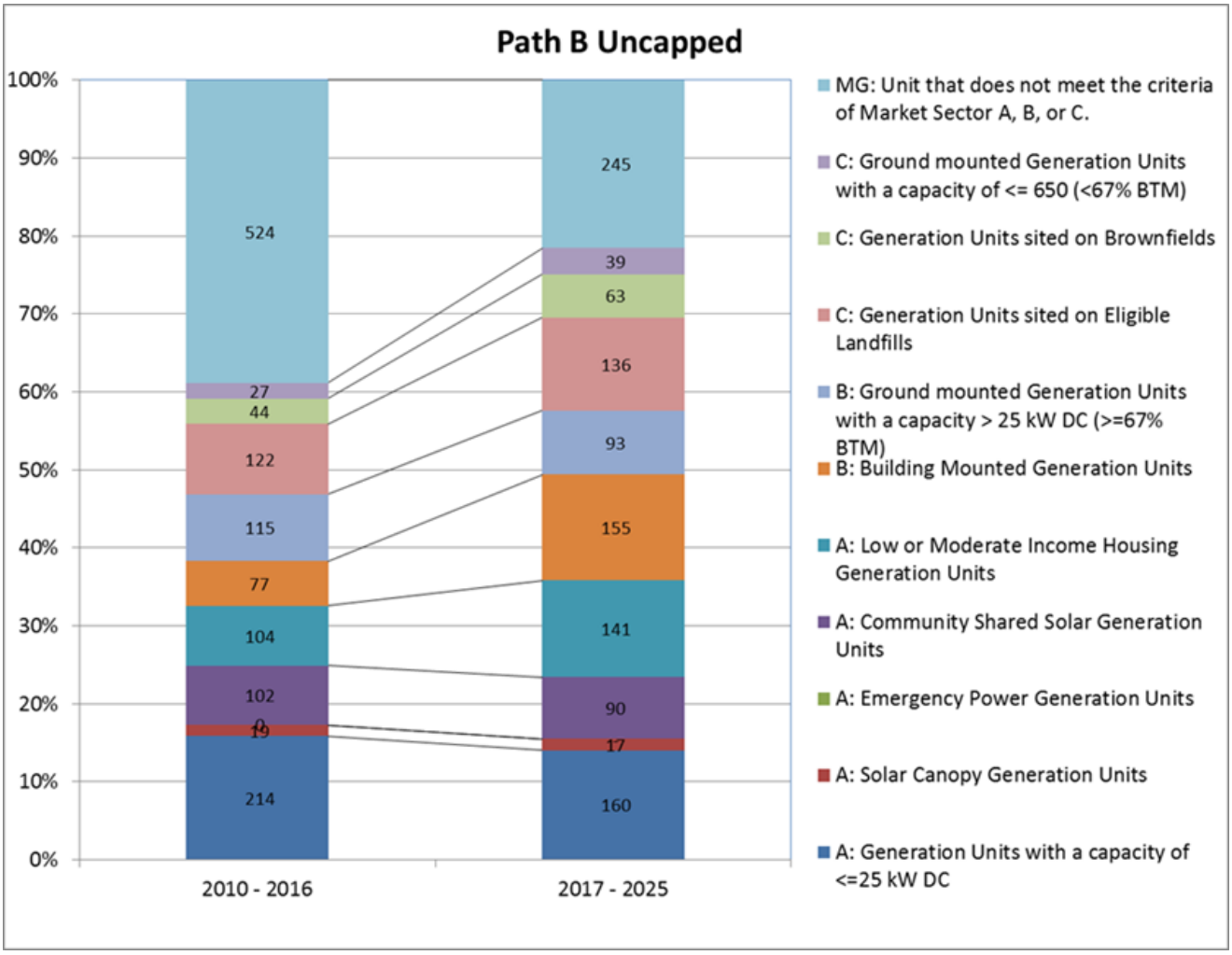


Figure 23: Policy B Uncapped Subsector Market Share Comparison Before and After 2017



6 Solar PV Incentives

The Solar PV Incentives differ per the policy definitions. For the SREC policies the solar PV incentives are comprised of the Solar Renewable Energy Credits which are the market based tradable certificates which are a component of the supply-responsive demand formula and floor price auction mechanism all part and parcel of SREC-I and SREC-II.

As described above, Policy Paths A & B use a different approach; all are based on fixed-price performance-based incentives distributed via either open declining block incentive or EDC-conducted competitive solicitation. For purposes of this study, we have established initial DBI prices and rates of decline that attempt to match the level of incentive that would induce installation growth to 2500 MW by 2025. These incentives are in addition to the implicit value of avoiding retail energy charges for sized-to-load solar projects, or the explicit net metering incentives of virtual net metering or roll forward beyond the billing month net metering. Incentives were projected for 2 small segments and 4 large segments for Policy Paths A and B, and because the incentive structure is intended to equalize gross payments across different utilities, a set of prices was established for each of 6 EDCs. In order to not unduly burden the reader, we describe here the results for two segments of Policy Path A (Small Residential and Large Sector A). The assumed incentive levels for all of these segments and EDCs for both Policy Paths A and B are shown in Appendix C for Policy Paths .

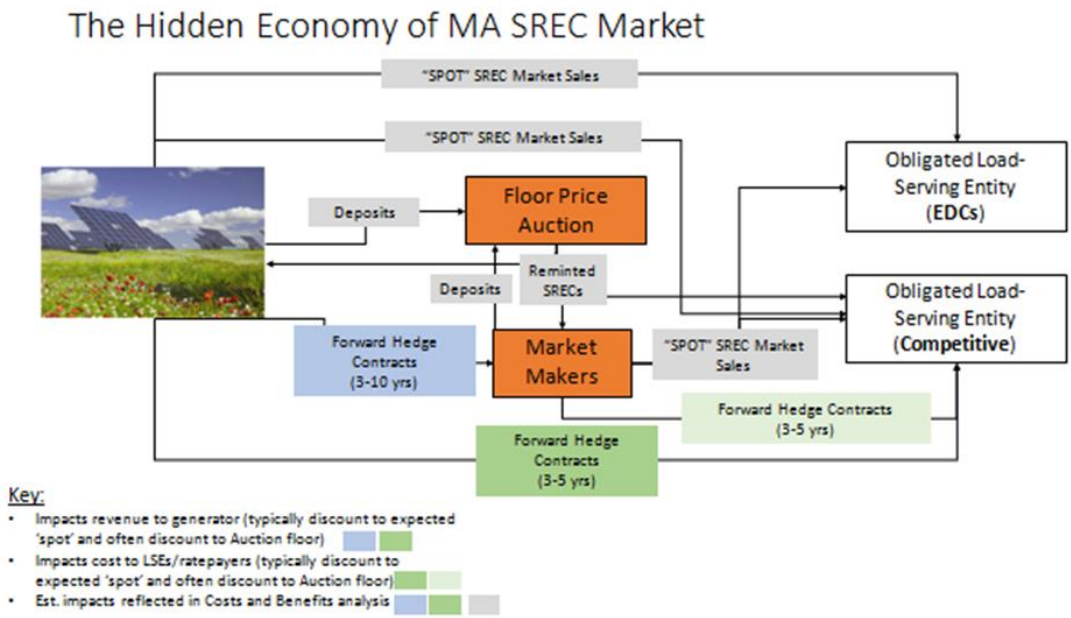
6.1 Projected SREC Prices, CG Revenues and NPR Costs

In order to estimate SREC prices in the past, present and future, the following combination of information and forecasting was used.

- Modeled estimates of SREC prices using SEA's proprietary Massachusetts Solar Market Study fundamentals analysis of resulting in supply, demand and ultimately SREC spot prices, as well as floor-price auction dynamics.
- Historic spot SREC prices as well as research on 3, 5 and 10 year forward strip prices used to hedge both generator and load serving entity SREC price risk.
- Forward strip prices were calculated as a function of projected spot prices

As displayed in Figure 25, sometimes CGs sell directly to LSEs, in that case we assume the revenue to CGs and the cost to LSEs (and ultimately the NPRs) is equivalent. In other cases, CGs sell to market makers or participate in the Floor Price Auction and the revenue to CGs and the cost to the NPRs are not equivalent. In these cases the Market Makers absorb the difference, in many cases by being the buyer of the SRECs long-term and offering the CGs a price hedge. Market Makers do so with the goal of making a profit, but in turn take on the SREC price volatility risk.

Figure 24: Schematic Diagram of Hedging Transactions within the SREC Carve-out Market



6.1.1 Net Metering Capped (SREC-I, II and III)

Figure 25 displays the historic and projected SREC pricing with net metering capped at present levels. As can be seen prices decline more or less steadily as a function of SACP and auction floor declines for SREC-II and SREC-III. These declines in turn result in lower prices for forward strip hedges (and less revenue to CGs and less costs to NPRs).

Figure 26 displays the annual realized SREC revenue to CGs and costs to NPRs, the difference being (for the most part) revenue to market makers and to a much lesser degree SACP payments and transaction costs. On a 2015 NPV basis, the aggregate revenue to CGs is $3.383 billion while the NPV costs to NPRs is $3.970 billion, a ratio of 0.85.

Figure 25:
Historic and Predicted SREC Spot Prices with Net Metering Caps Unchanged from Present Policy

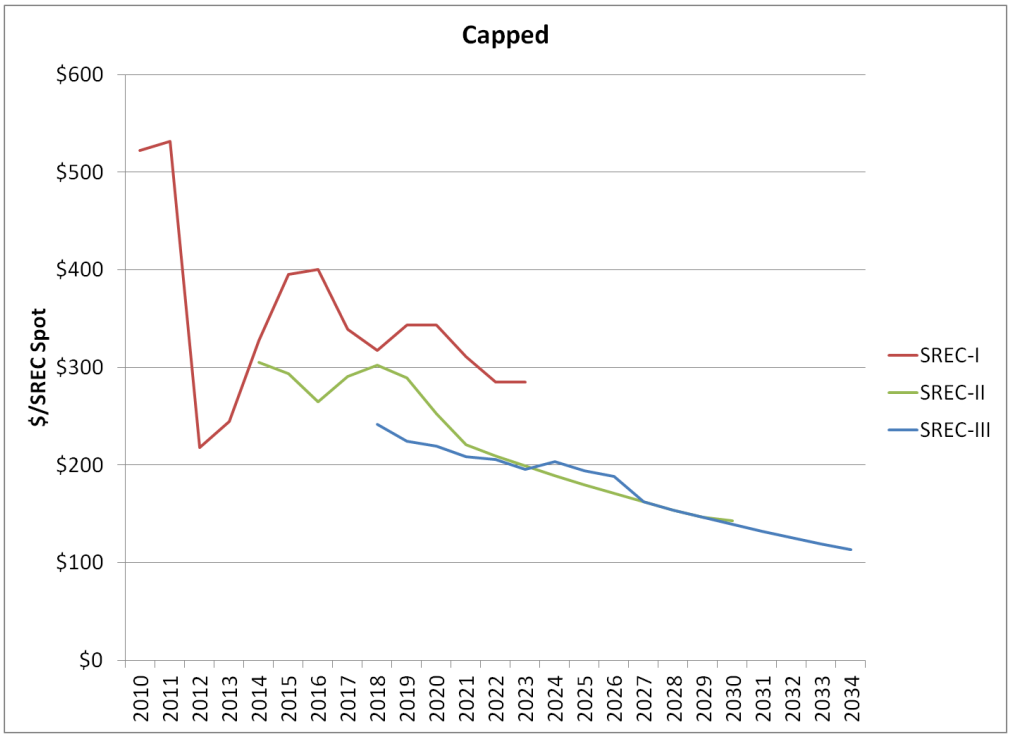
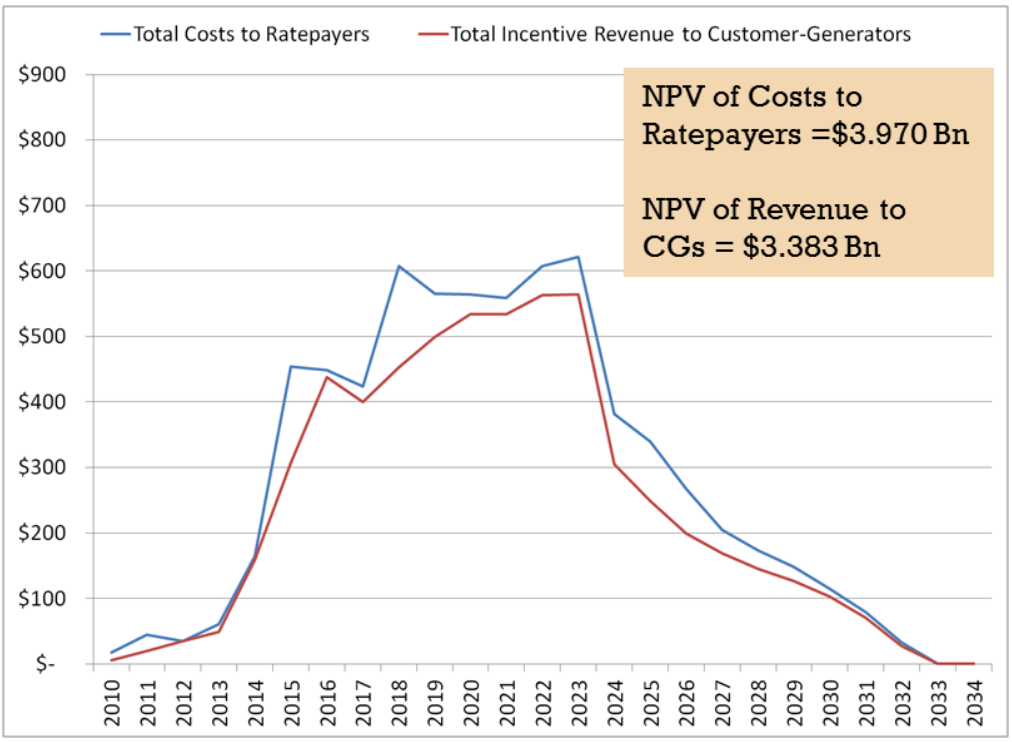


Figure 26: Annual Realized Costs NPRs and Revenues to CGs with Net Metering Caps Unchanged from Present Policy



6.1.2 Net Metering Uncapped (SREC-I, II and III)

Figure 27 displays the historic and projected SREC pricing with net metering uncapped. Again, prices decline more or less steadily as a function of SACP and auction floor declines for SREC-II and SREC-III. Prices for the SREC-III program are higher for the uncapped scenario than the capped SREC-III scenario, in part because the supply-responsive demand mechanism is overwhelmed by strong growth in supply. The sharp increases in supply cause sharp increases in demand which then can't be met when the program reaches the SREC-III cap of 2500 MW.

Figure 28 displays the annual realized SREC revenue to CGs and costs to NPRs for the uncapped scenario; the difference being for the most part revenue to market makers and, to much lesser degree, SACP payments and transaction costs. On a 2015 NPV basis the aggregate revenue to CGs is $3.434 billion while the NPV costs to NPRs is $4.016 billion a benefit cost ratio of 0.86.

Figure 27: Historic and Predicted SREC Spot Prices with Net Metering Uncapped

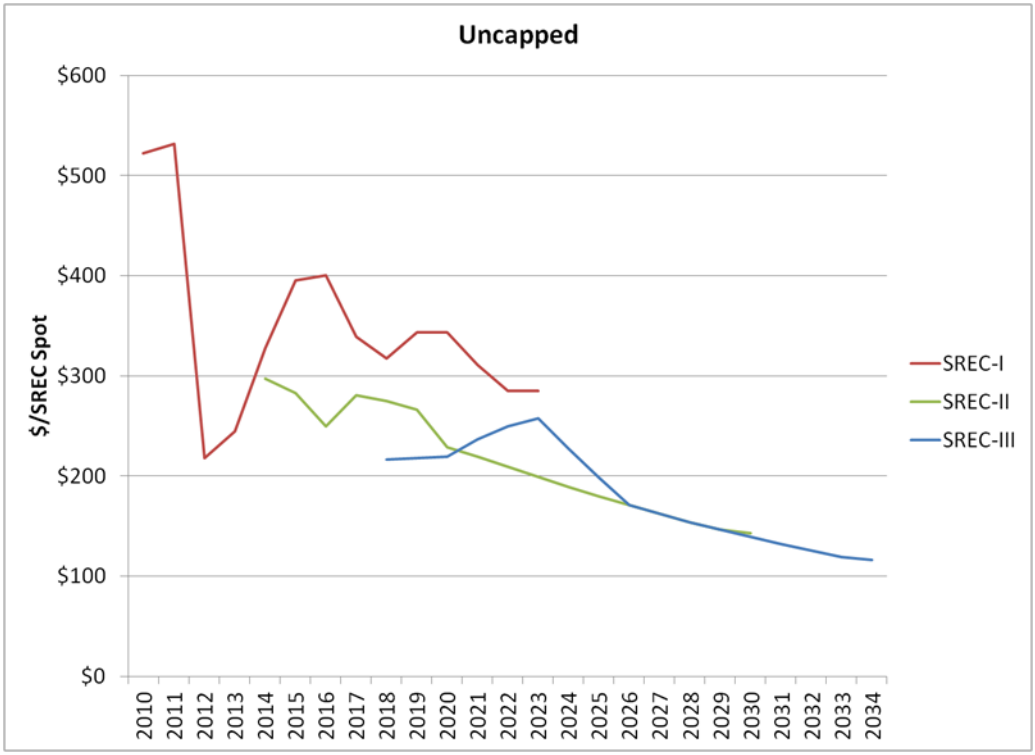
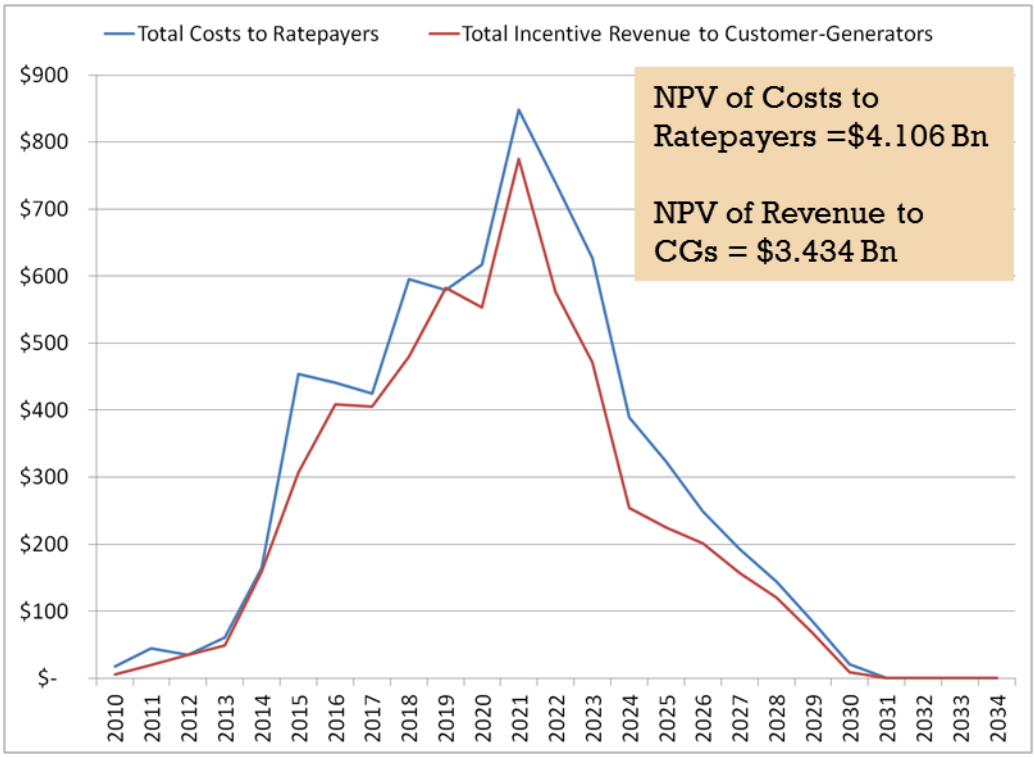


Figure 28: Annual Realized Costs NPRs and Revenues to CGs with Net Metering Caps Uncapped



6.2 Policy Path A

6.2.1 Policy Path A: Small Residential DBI/PBI

The combined incentives for projects are set at the level so that residential projects can be built, and as possible at projected solar costs and retail rate levels, reach their portion of the 2500 MW target in 2025 with more or less moderate growth from the start in 2017. The initial solar incentive level is based on the difference of the combined incentive level less the retail rate for the host utility in 2017. As the combined incentive blocks decline and retail rates increase, the solar incentives drop with each successive round. Unitil has the lowest solar incentive as it has the highest rates for avoided kWh avoided charges. Conversely National Grid has the lowest residential rates for avoided kWh charges, thus the highest incentives.

Incentive prices hit zero when there is parity with the avoidable kWh portion of retail rates (we will refer to this as retail rate parity for the purposes of this incentive). Unitil has the highest retail rates, thus hits parity first. We do not allow incentives to be negative. "Gating", the restriction on program participation, is the only thing that stops the market from taking off. One could imagine that sized to load customers in this sector would not participate in the program post 2023 because avoiding retail rates is sufficient incentive for solar development.

Figure 29 and Figure 30 display the $/MWh incentives for the Path A Capped Small Residential and the Path A Uncapped Small Residential program. As residential customers can always net meter regardless of the cap and we assume that 90% of the production is sized-to-load for a residential project, the results are almost identical.

Figure 29: $/MWh Incentives for the Path A Capped Small Residential Program

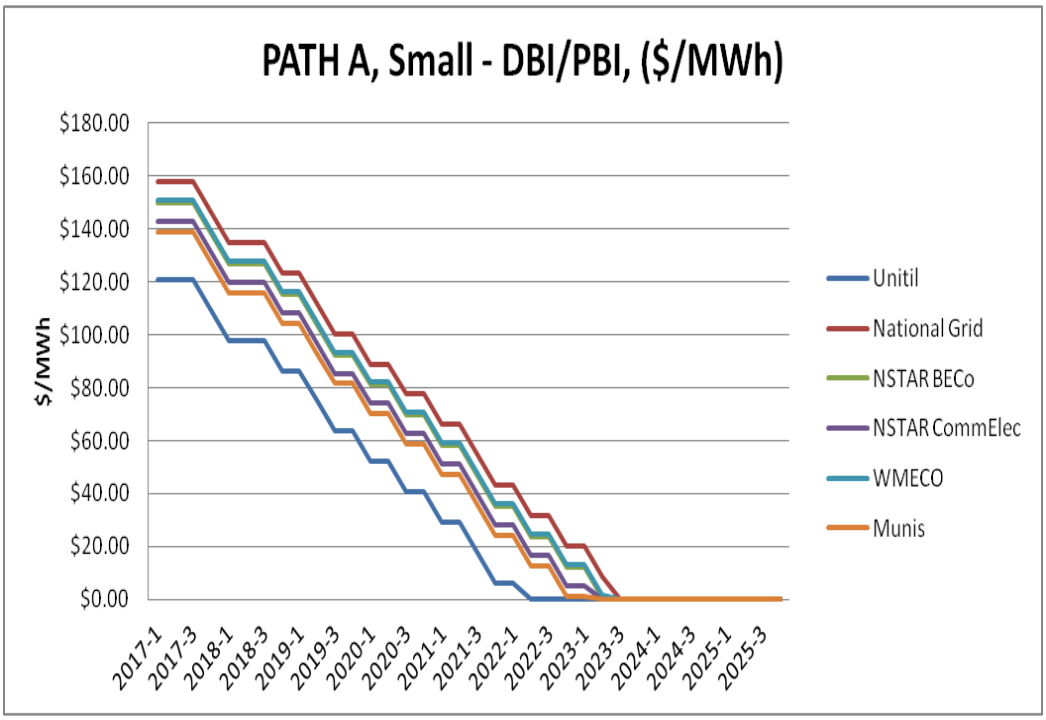
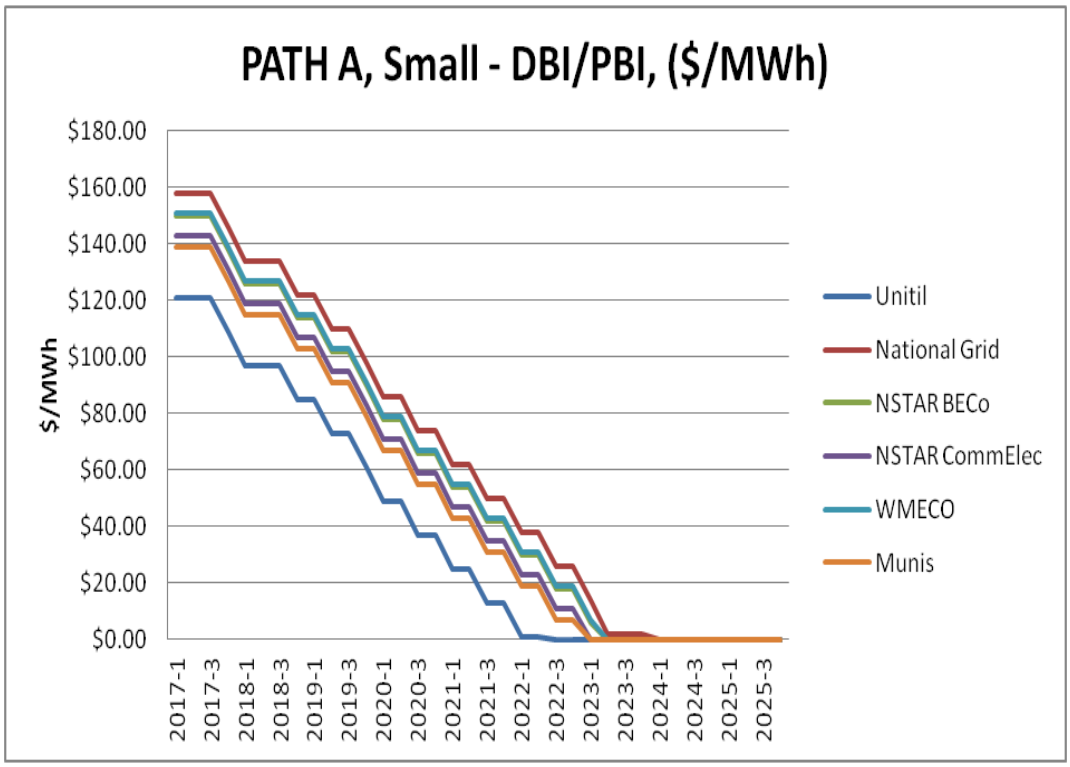


Figure 30: $/MWh Incentives for the Path A Capped Small Residential Program



6.2.2 Policy Path A: Large Competitive PBI – Sector A

The Policy Path A large competitive sectors show similar characteristics across the four SREC-II Market Sectors for which distinct solicitations with their own targets are run.

The Sector A, NM capped scenario is just Solar Canopy, Emergency Generation, and on-site Affordable Housing projects as VNM Affordable Housing and Community Shared Solar projects are no longer viable (as we know them today) without VNM. The $/MWh incentive results are shown in Figure 31. While the combined incentive over time decreases, it never reaches the level where additional solar incentives are not needed.

Figure 31: $/MWh Incentives for the Path A Capped Large Sector A Program

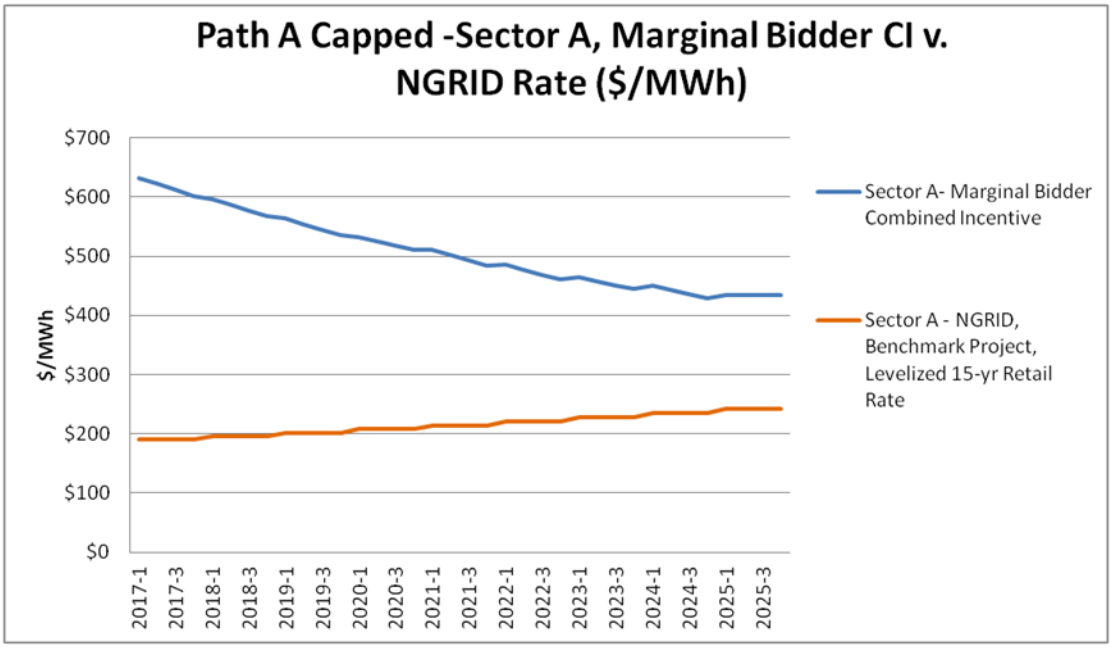
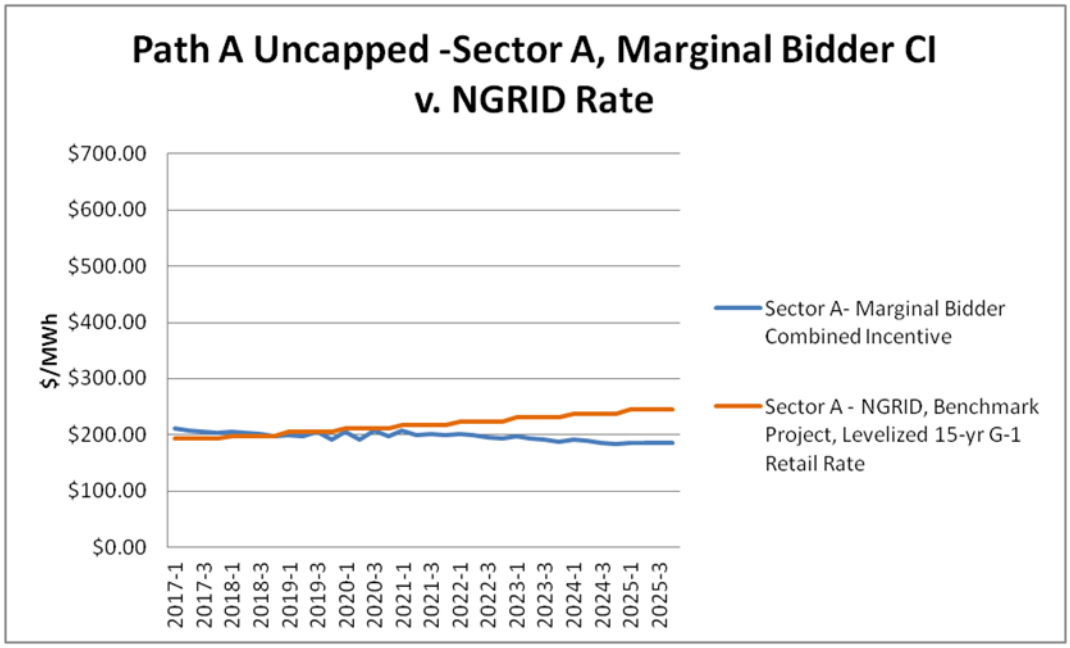


Figure 32 shows the $/MWh incentives but this time for the uncapped scenario for Policy Path A that now includes VNM-dependent projects (CSS and VNM Affordable Housing). As can be seen, for a project sized to load[18] the combined incentive needed from the marginal bidder becomes lower than the combined incentive in approximately 2019. In this case the project growth would take off except that we assume that net metering availability is restricted to only program participants. As the model (which presumes a degree of perfect foresight) did not allow for bids to fall below the projected levelized retail rate revenue (which would signify a negative solar incentive), more and more of the sized-to-load projects will bid at prices equal to projected levelized retail rate revenue for their required Combined Incentives.

[18] Within Sector A, with net metering values reduced to wholesale rates, oversized projects are no longer competitive.

Figure 32: $/MWh Incentives for the Path A Uncapped Large Sector A Program



This modeling approach, which impacts all four large sectors to differing degrees, has some interesting impacts. The model assumes that a project cannot bid, via competitive solicitation, lower than the levelized 15-year value of Rate-Based incentives ("Levelized Rates") it is forecasted to receive. Because of this, the Combined Incentive which the marginal bidder bids is, in some cases, lower than the projected Levelized Rates offered in certain utilities (e.g.: National Grid and Unitil). The result of this is that, when the marginal Combined Incentive and a utility's Levelized Rates cross, additional projects in said utilities can no longer compete in the solicitation (again e.g., National Grid and Unitil). This shifts installations, over time, to the utilities with the lowest Levelized Rates.

With perfect foresight, projects would not bid to participate at a lower revenue than they could receive by simply building an installation and receiving full retail rates. Because rates are projected to rise, but not guaranteed to do so, in practice, we would expect that many projects, not having perfect foresight, would accept a fixed combined revenue stream below forecasted retail revenues. As a result, the model likely results in more costly projects and a less cost-effective mix than would be experienced.

See Appendix C for results for Sectors B, C and D in net metering capped and uncapped scenarios.

6.3 Policy Path B

6.3.1 Policy Path B: Small Residential DBI/EPBI

Small Residential Path B differs from Path A in that the incentives are an Expected PBI, or an upfront rebate in $/kW with the revenue stream from the solar system assuming some level of kWh production. The trajectory of the incentives required are very similar to Policy Path A small residential (see Figure 33); it reaches grid parity in approximately 2023 for most utilities. The uncapped scenario is exactly the same as the capped scenario (see Figure 34).

Figure 33: $/kW Incentives for the Path B Capped Small Residential Program

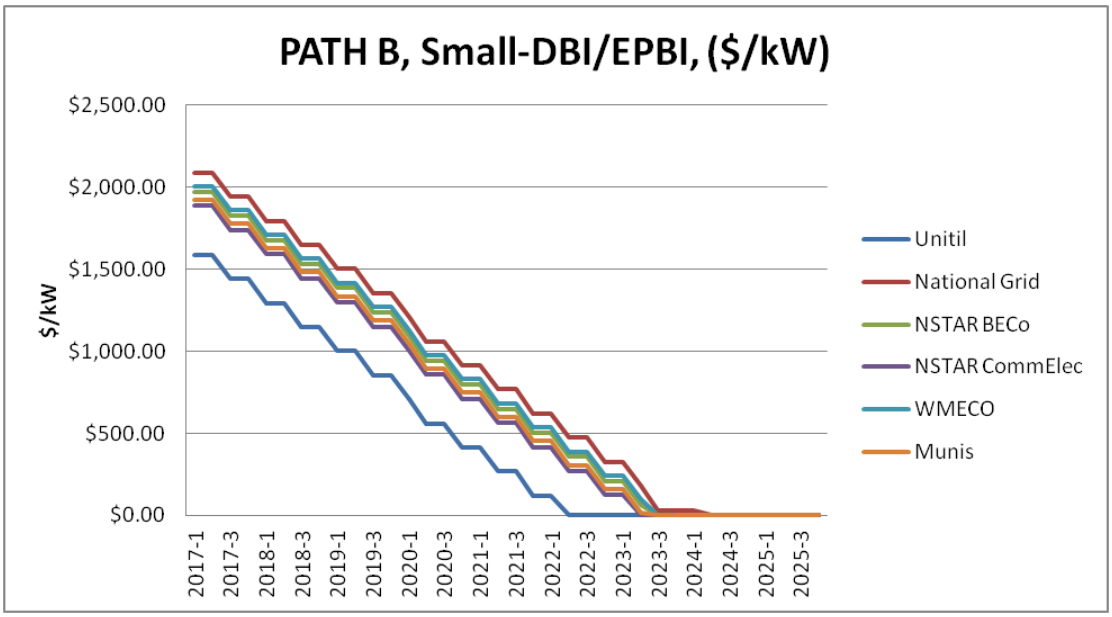
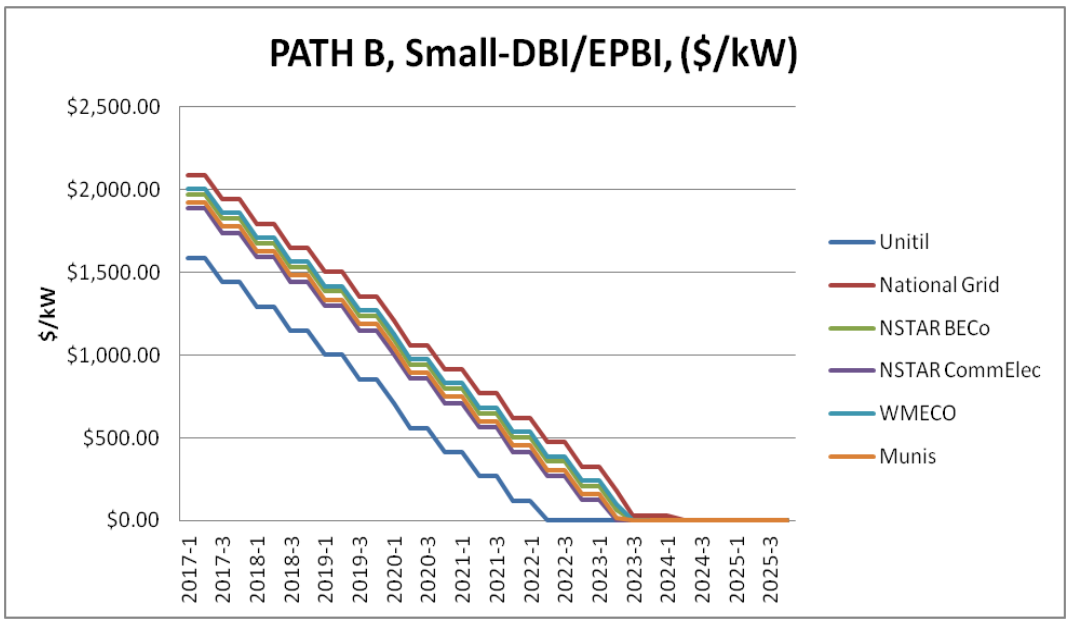


Figure 34: $/kW Incentives for the Path B Uncapped Small Residential Program



6.3.2 Policy Path B: Sector A DBI/PBI

The Policy Path B large sectors show similar characteristics to each other.

Again just like Policy Path A, within Sector A the capped scenario is just Solar Canopy, Emergency Generation, and on-site Affordable ~~Housing projects, as VNM Affordable Housing and Community Shared Solar projects are no longer viable (as we know~~ them today)

without VNM. The $/MWh incentive results are shown in Figure 35. Under the DBI incentive structure, the combined incentive steps down as each DBI block target is reached. Unlike Policy Path A, the program does reach a level where solar incentives (beyond retail kWh rate levels) are not needed.

Figure 35: $/MWh Incentives for the Path B Capped Large Sector A Program

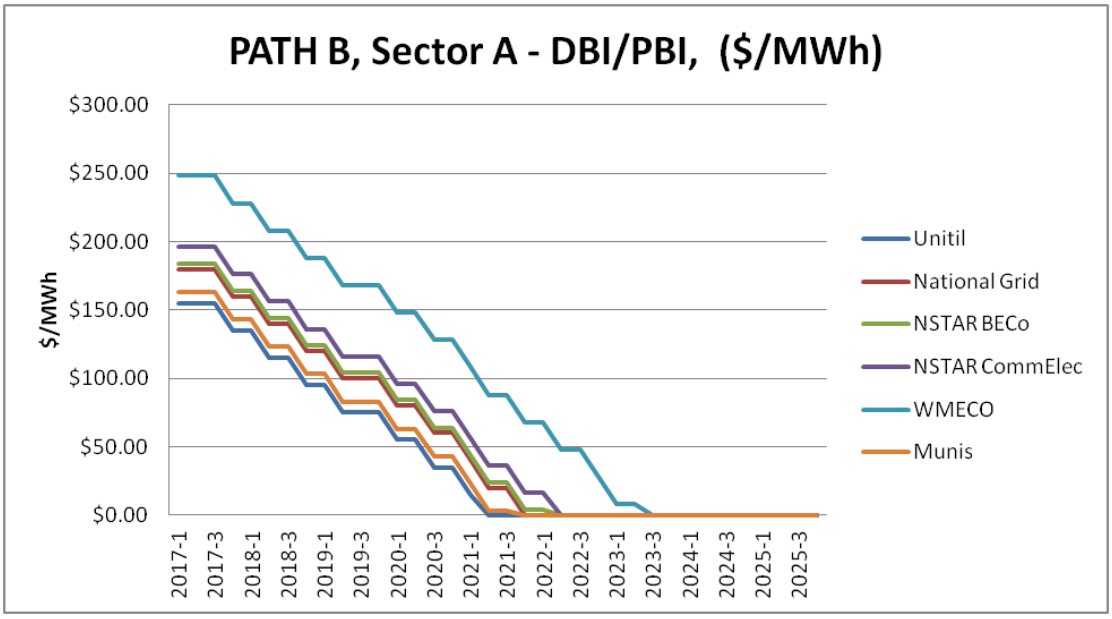
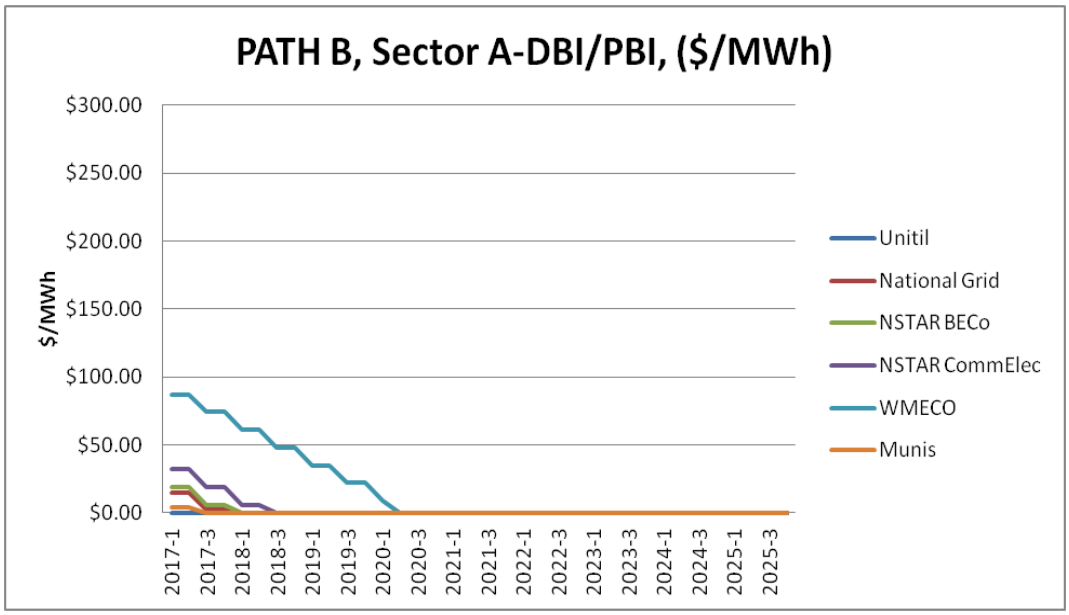


Figure 36 shows the $/MWh incentives, but this time for the uncapped scenario for Policy Path A, and now includes VNM-dependent projects (CSS and VNM Affordable Housing). Again the solar incentive needed from the marginal bidder drops to zero very quickly, as CSS and VNM Affordable Housing can exist with just the VNM revenue.

While not shown here (See Appendix C), Sector C and Sector D capped projects are modeled to receive wholesale QF rates and thus would need solar incentives to 2025 and beyond.

Figure 36: $/MWh Incentives for the Path B Uncapped Large Sector A Program



6.4 Caveats to Modeling Results

The discussion of perfect foresight and Policy Path A bid modeling in Section 6.2.2 exposes a modeling artifact which may serve to overstate the cost-effectiveness of Policy Path A, Uncapped. It applies in some of the other sectors but to a lesser degree than in Sector A. The reasons this would overstate cost-effectiveness (compared to Policy Path B) is because under Policy Path B, projects with the highest retail kWh charges will continue to build until the end of the program. In contrast, in Policy Path A, when the marginal bid falls below the projected levelized retail rate value, projects in EDCs with the highest retail rate values cannot win bids and are foreclosed from installation. This cleaves off solar and net metering incentive payments in EDCs with the highest retail kWh charges, resulting in not over-incentivizing via net metering projects which are so incentivized in Policy Path B.

7 Cost and Benefit of the Current (SREC) Policy

This Section presents and compares the cost and benefit of the current SREC Policy across the four perspectives under three different policy scenarios: SREC Policy to 1,600 MW (Capped), SREC Policy to 1,600 MW (Uncapped) and SREC Policy to 2,500 MW (Capped). As noted in previous Sections, this Study does not include a cost and benefit analysis for SREC Policy to 2,500 MW under an uncapped net metering scenario.

7.1 SREC Policy 1600 MW

Results presented here cover projected results of SREC-I and SREC-II when allowed to run its full course. Results are similar for the capped and uncapped scenarios. This occurs for two reasons.

1. Most of the 1600 MWs are built before the constraints of net metering caps have a material impact on the market; and
2. Under a capped scenario, residential/small building-mounted systems that could continue to take advantage of net metering continue to be built after the cap reached for other sectors.

7.1.1 Capped

Results for the capped scenario are summarized in in A Figure 37, which shows (in the bar chart) the height of the bars as NPV 2015$, and also shows as data labels the NPV $/MWh, which are in proportion to the height of the NPV bars (all having the same MWH denominator).

Across the four perspectives, non-owner participants (NOP), the beneficiaries of lease payments, property tax or PILOT payments, or PPA or net metering discounts, would experience substantial net benefits, based on the difference between NPV benefits of $1.0 billion and costs (comprised of tax liabilities on the benefits) of NPV $281 million under SREC Policy to 1,600 MW (Capped).

From the Customer-Generators (CGs) perspective, the difference between benefits and costs (always a net benefit) represents returns to equity and debt investors, and can be thought of as profit margin (a portion of which assumed to stay in state and flow to C@L). CGs are projected to experience benefits (comprised of all sources of revenue) of NPV $9.3 billion compared to costs of $7.05 billion.

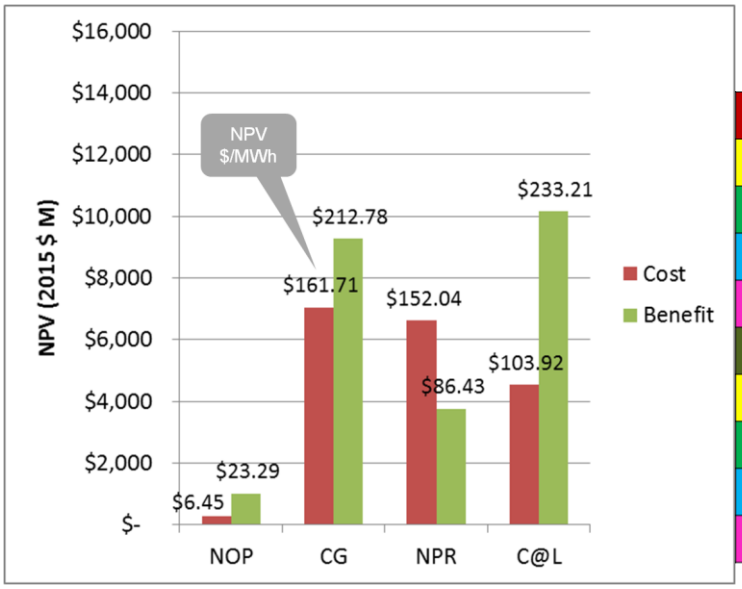
Non-participating ratepayers (NPRs) fund the incentives, so it is no surprise that they incur net costs. NPV costs are $6.6 billion compared to benefits of $3.766 billion. While the table below does not break out the relative costs and benefits of SREC-I vs. SREC-II, SREC-II is notably more cost-effective than SREC-I, so a larger pro-rata share of the cost-to-benefit- differential is attributable to SREC-I.

The perspective of citizens of the Commonwealth at Large (C@L) experiences material net benefits, the source of which vary from scenario to scenario. Total NPV benefits of $10.2 billion compare to total NPV of net costs[19] of NPV $4.5 billion.

[19] Note that the way the costs and benefits are rolled up, and particular cost or benefit component can be characterized as either a cost or a benefit. For some cost or benefit components, there are both costs and benefits which either cancel (netting to zero) or result in a net cost or benefit for that individual component. In a very few instances, this calculation approach can lead to slightly counterintuitive results, which become more intuitive once this netting is understood. See Section 4 and Appendix D for a description of how individual cost and benefit components are calculated for each perspective to see where this netting occurs.

Discussion of the detailed components of the costs and benefits can be found in Section 8.

A Figure 37: Cost and Benefit of SREC Policy to 1,600 MW (Capped) by Perspectives



	NPV (2015 $ M)	NPV $/MWh
Cost		
NOP	$ 281	$ 6.45
CG	$ 7,046	$ 161.71
NPR	$ 6,625	$ 152.04
C@L	$ 4,528	$ 103.92
Benefit		
NOP	$ 1,015	$ 23.29
CG	$ 9,272	$ 212.78
NPR	$ 3,766	$ 86.43
C@L	$ 10,162	$ 233.21

7.1.2 Uncapped

Under the net metering uncapped SREC policy through 1600 MW, the results are summarized as follows, for each perspective:

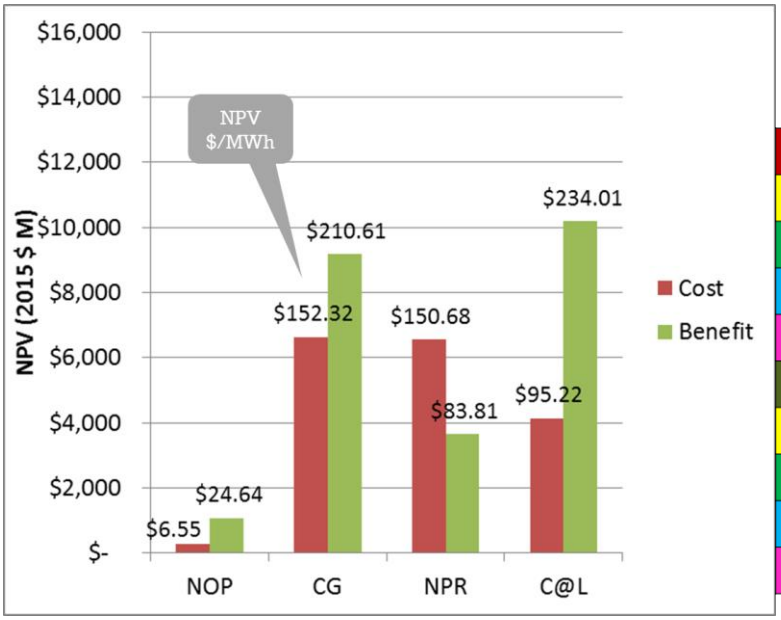
NOPs, the beneficiaries of lease payments, property tax or PILOT payments, or PPA or net metering discounts, would experience substantial net benefits, based on the difference between NPV benefits of almost $1.1 billion and costs (comprised of tax liabilities on the benefits) of NPV $285 million.

From the CG perspective, they are projected to experience benefits of NPV $9.2 billion (slightly less than under the capped s scenario) compared to costs of $6.6 billion. This reflects a different mix of generation units more heavily weighted towards larger projects with lower $/kW installed costs, resulting in an increased profit margin.

NPRs fund the incentives, with of NPV costs at $6.6 billion compared to benefits of $3.65 billion, a similar but slightly higher net cost that corresponds in part by the higher profit margin to CGs but is also attributable to other dynamics.

The C@L perspective experiences material net benefits, the source of which vary from scenario to scenario. Total NPV benefits of $10.2 billion compare to total NPV of net costs of NPV $4.1 billion, making this scenario more attractive on net to C@L. This is due to a larger share of more cost-efficient installations (e.g., medium and large commercial systems) that can be supported by net metering under the uncapped scenario.

Figure 38: Cost and Benefit of SREC Policy to 1,600 MW (Uncapped) by Perspectives



	NPV (2015 $ M)	NPV $/MWh
Cost		
NOP	$ 285	$ 6.55
CG	$ 6,631	$ 152.32
NPR	$ 6,560	$ 150.68
C@L	$ 4,145	$ 95.22
Benefit		
NOP	$ 1,073	$ 24.64
CG	$ 9,169	$ 210.61
NPR	$ 3,649	$ 83.81
C@L	$ 10,188	$ 234.01

7.2 SREC Policy 2500 MW, Capped

Results presented here cover projected results of SREC-I and SREC-II when allowed to run its full course through 1600 MW, plus the projected SREC-III policy, with net metering capped. As noted earlier, SREC-III was not analyzed for costs and benefits in a net metering uncapped future.

Figure 39 retains the same overall shape as A Figure 37 and Figure 38, but the numbers reveal some important impacts. With the SREC Policy expanding to 2500 MW in the net metering Capped scenario, it is not a surprise that It has higher total cost than reaching the 1600 MW targets. However, it is quite notable that all the $/MWh costs are lower and all the $/MWh benefits are lower for the 2500 MW scenario as well. This is in large part because SREC-III would be more cost-effective than its predecessors.

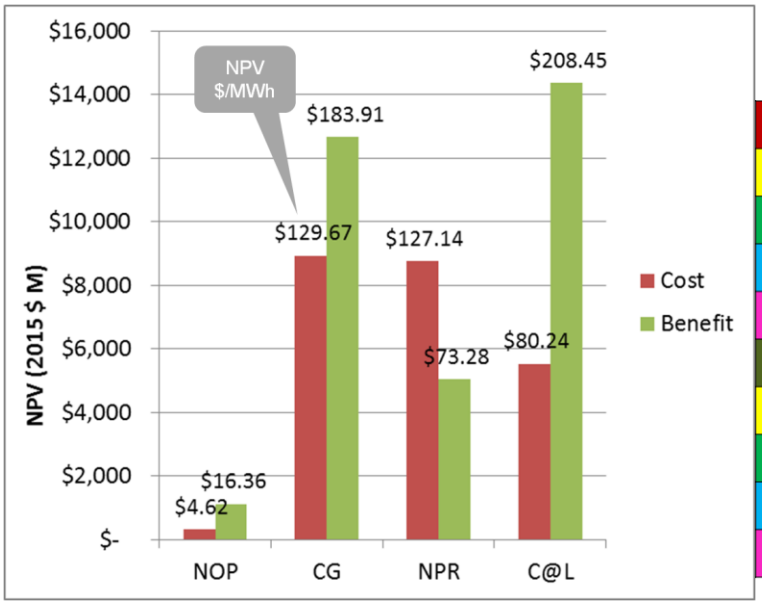
NOPs, the beneficiaries of lease payments, property tax or PILOT payments, or PPA or net metering discounts, would experience a similar level of benefits at $1.1 billion as at 1600 MW, but experience an increase in costs (tax liabilities) of NPV $318 million. It is clear why the NOP net benefits decrease, as there are fewer opportunities for non-owners to participate and yield substantial benefits when net metering is mostly unavailable.

CGs are projected to experience benefits of NPV $12.7 billion, reflecting the construction of a larger fleet, compared to costs of NPV almost $8.8 billion. These results reflects a different mix of generation units more heavily weighted towards smaller projects with higher $/kW installed costs.

Interestingly, the *net* costs (costs less benefits) to NPR at 2500 MW are lower than the *net* costs at 1600 MW under either capped or uncapped scenarios, showing that for SREC-III, the incremental benefits exceeded the incremental costs from the NPR perspective.

From the C@L perspective, net benefits increase with increasing volume of installations, even though the drivers of the costs and benefits to this perspective change with shifting installation mix. Total NPV benefits grow to almost $14.4 billion, compared to total NPV of net costs of NPV $5.5 billion.

Figure 39: Cost and Benefit of SREC Policy to 2,500 MW (Capped) by Perspectives



	NPV (2015 $ M)	NPV $/MWh
Cost		
NOP	$ 318	$ 4.62
CG	$ 8,932	$ 129.67
NPR	$ 8,758	$ 127.14
C@L	$ 5,527	$ 80.24
Benefit		
NOP	$ 1,127	$ 16.36
CG	$ 12,668	$ 183.91
NPR	$ 5,048	$ 73.28
C@L	$ 14,358	$ 208.45

8 Comparisons of Cost and Benefit Results by Perspective

This Section compares the costs and benefits of each of the four perspectives as well as the total NPV of total costs and benefits for each policy scenario in each of the four perspectives.

Please note that wherever the cost benefit component stacks are presented (Table 19, Table 20,Table 21, and Table 22 and Appendix B) every row will be either a cost or a benefit. However, many rows have both costs and benefits that either net to zero and are not shown, or have a net benefit or net cost with a smaller absolute value because of netting costs and benefits within that cost or benefit component. In a very few instances, this calculation approach can lead to slightly counterintuitive results, which become more intuitive once this netting is understood. See Section 4 and Appendix D for a description of how individual cost and benefit components are calculated for each perspective to see where this netting occurs.

8.1 Total Costs & Benefits, NOP Perspective

Non-owner participants (NOPs) are beneficiaries of policies – landowners receiving land lease payments, towns receiving property taxes or PILOTs, and PPA/NMC offtakers. So it is no surprise that this perspective includes mostly benefits. Table 19 is an illustrative table of the stacked costs and benefits from the NOP perspective in the SREC capped policy future. Similar tables for other scenarios can be found in Appendix B. Under the current policy, VNM is the largest piece of the benefits stack, followed by lease payments, avoided rates from displacing on-site load, and property taxes in that order. The only costs to NOP are taxes. As opposed to the benefits in the SREC capped scenario presented in Table 19, in an uncapped policy scenario, VNM benefits to NOP are higher and the benefits from on-site generation lower because of the shift in project mix to more cost effective, VNM-intensive projects. Costs stay fairly the same across policy futures but vary depending on the variance of project mix driven by net metering policy. With net metering, public offtakers are the most attractive as large projects qualify for Class II net metering. Without net metering, there would only be public offtakers if projects were sited on public buildings or sites with load (e.g., city wastewater treatment plants). Thus aggregate tax costs tend to be higher in capped policy scenarios. NOP costs and benefits are smaller relative to those of other perspectives. Variation among policy scenarios is mostly a function of the project mix (amount of taxable offtakers and VNM projects).

Table 19: Comparing NOP Detailed Costs and Benefits – SREC Capped

Benefits

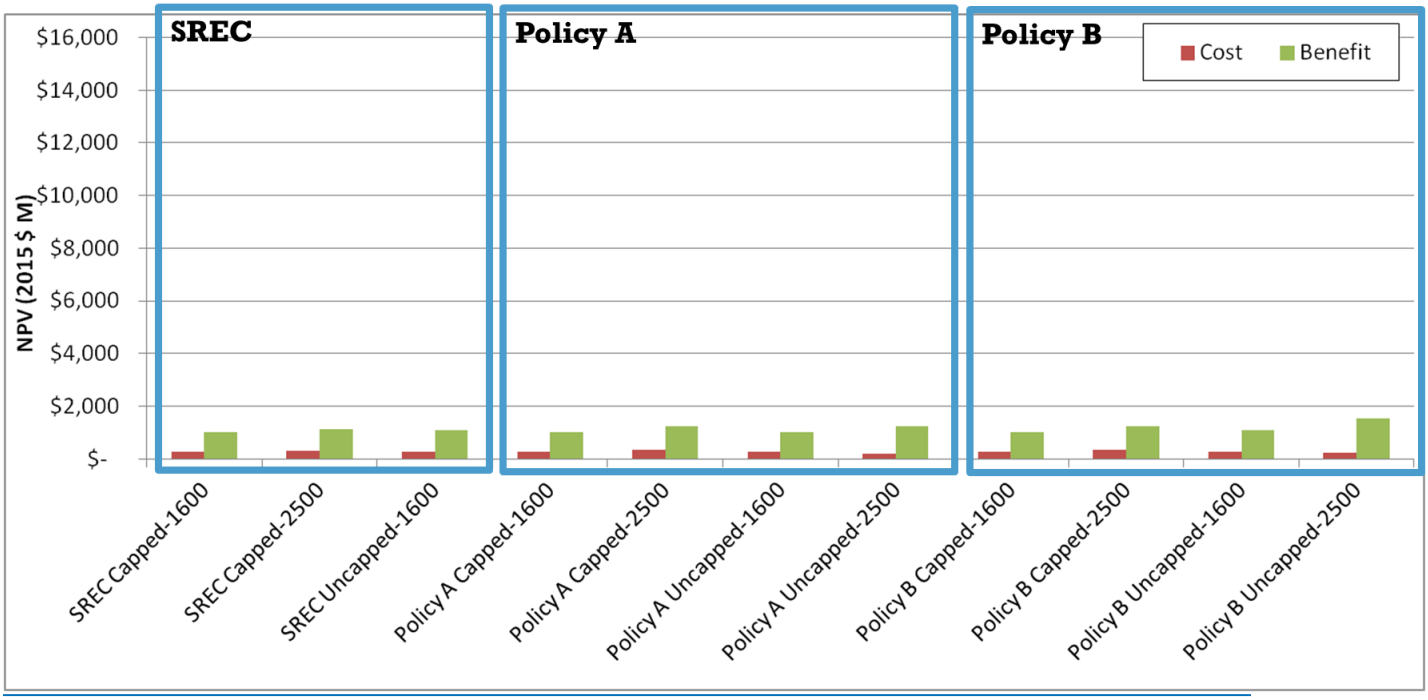
C/B Component ↓	CB Code	2500 MW NPV Benefits (Million $)	2500 MW NPV $/MWh Benefits	1600 MW NPV Benefits (Million $)	1600 MW NPV $/MWh Benefits
Lease Payments	CB1.3	$ 228.2	$ 3.3	$ 209.0	$ 4.8
PILOTs / Property Taxes	CB1.4	$ 152.6	$ 2.2	$ 148.1	$ 3.4
Generation Value of On-site Generation	CB3.1	$ 155.3	$ 2.3	$ 104.1	$ 2.4
Transmission Value of On-site Generation	CB3.2	$ 25.4	$ 0.4	$ 17.5	$ 0.4
Distribution Value of On-site Generation	CB3.3	$ 63.5	$ 0.9	$ 42.5	$ 1.0
Other Retail Bill Components (Trans., EE, RE)	CB3.4	$ 9.6	$ 0.1	$ 7.2	$ 0.2
Offsetting On-site Usage	CB4.1	$ 16.4	$ 0.2	$ 10.6	$ 0.2
Virtual NM	CB4.2	$ 476.0	$ 6.9	$ 476.0	$ 10.9
Total		**$ 1,127.1**	**$ 16.4**	**$ 1,015.0**	**$ 23.3**

Costs

C/B Component ↓	CB Code	2500 MW NPV Costs (Million $)	2500 MW NPV$/MWh Costs	1600 MW NPV Costs (Million $)	1600 MW NPV $/MWh Costs
MA Income Taxes	CB1.6.b	$ 59.2	$ 0.9	$ 52.3	$ 1.2
Federal Income Taxes	CB1.7b	$ 258.8	$ 3.8	$ 228.7	$ 5.2
Total		**$ 318.0**	**$ 4.6**	**$ 280.9**	**$ 6.4**

Figure 40 shows the NPV of total costs and benefits from the NOP perspective for each policy future. As we keep the y-axis scale equal for the analogous figures for all four perspectives (to ease visual comparisons) the NOP total costs and benefits bars appear very short compared to the y-axis as the sums are relatively small compared to other perspectives. Total benefits of Policy B uncapped are slightly more than those in other policy futures. This is mostly a function of a shift in project mix to more VNM projects which provide the most benefits to NOPs.

Figure 40: Total NPV Costs & Benefits, NOP Perspective



8.2 Total Costs & Benefits, CG Perspective

In the customer generator (CG) perspective, the costs and benefits (revenues) drive profitability of the CG. Table 20 is an illustrative table of the stacked costs and benefits from the CG perspective in the SREC capped policy future. Similar tables for other scenarios can be found in Appendix B. Under the current policy, the difference between NPV of total costs and total benefits to the CG is $2.2 billion. Profits to CG are $3.7 billion in the SREC capped to 2500 MW policy future, a $1.3 billion increase over the additional 900 MW. Not surprisingly, in all policy scenarios, the total profitability of CG increases when the 2500 MW goal is met as compared to having a 1600 MW target. The largest component of CG benefits come from the direct incentives. In the case of SREC capped to 2500 MW, more than 30% of total CG benefits come from direct incentives. After direct incentives, much of the benefits, or revenues, come from the VNM value, and the avoided kWh charges.. In all policy futures with a 2500 MW goal, the federal ITC makes up about $1.3 billion of total CG benefits, ranging from about 10% to 12% of the NPV of total benefits. In uncapped policy futures, the VNM benefits are a large driver of increased revenues. In Policy A and Policy B capped scenarios, wholesale market sales will replace VNM benefits since projects which receive wholesale market value of generation are not viable in SREC scenarios.

The largest costs to CG are the system installed costs, ongoing O&M, and taxes. The system installed costs do not vary much across policies except for being about $400 billion higher in the SREC capped to 2500 MW scenario than other policy futures to 2500 MW. This is because of the larger amount of <= 25 kW installation in this scenario as compared to others which have a higher installed cost per kW. Ongoing O&M costs also do not vary significantly across policy futures. Taxable income of CGs vary across policy futures depending on types of project being built. In the SREC policy, CG taxable income is much smaller because the taxable generation value is less since small projects make up the majority of installations (and residential customers will not incur extra tax liability for avoiding electricity charges).

Table 20: Comparing CG Detailed Costs and Benefits – SREC Capped

Benefits

		2500 MW		1600 MW	
C/B Component ↓	CB Code	NPV Benefits (Million $)	NPV $/MWh Benefits	NPV Benefits (Million $)	NPV $/MWh Benefits
ROI (Aggregate Return to Debt & Equity)	CB1.5	$ -	$ -	$ -	$ -
MA Residential RE Tax Credit	CB1.6.a	$ 134.0	$ 1.9	$ 56.7	$ 1.3
Federal Incentives (ITC)	CB1.7a	$ 1,304.8	$ 18.9	$ 1,258.7	$ 28.9
Direct Incentives (e.g., SRECs)	CB2.1	$ 4,373.7	$ 63.5	$ 3,565.2	$ 81.8
Generation Value of On-site Generation	CB3.1	$ 2,263.9	$ 32.9	$ 940.0	$ 21.6
Transmission Value of On-site Generation	CB3.2	$ 376.3	$ 5.5	$ 163.9	$ 3.8
Distribution Value of On-site Generation	CB3.3	$ 1,010.5	$ 14.7	$ 404.4	$ 9.3
Other Retail Bill Components (Trans., EE, RE)	CB3.4	$ 129.6	$ 1.9	$ 62.7	$ 1.4
Offsetting On-site Usage	CB4.1	$ 323.0	$ 4.7	$ 130.9	$ 3.0
Virtual NM	CB4.2	$ 2,563.0	$ 37.2	$ 2,563.0	$ 58.8
Wholesale Market Sales	CB4.3	$ 69.0	$ 1.0	$ 48.4	$ 1.1
Avoided Generation Capacity Costs	CB5.3	$ 120.1	$ 1.7	$ 77.8	$ 1.8
Total		**$ 12,668.0**	**$ 183.9**	**$ 9,271.7**	**$ 212.8**

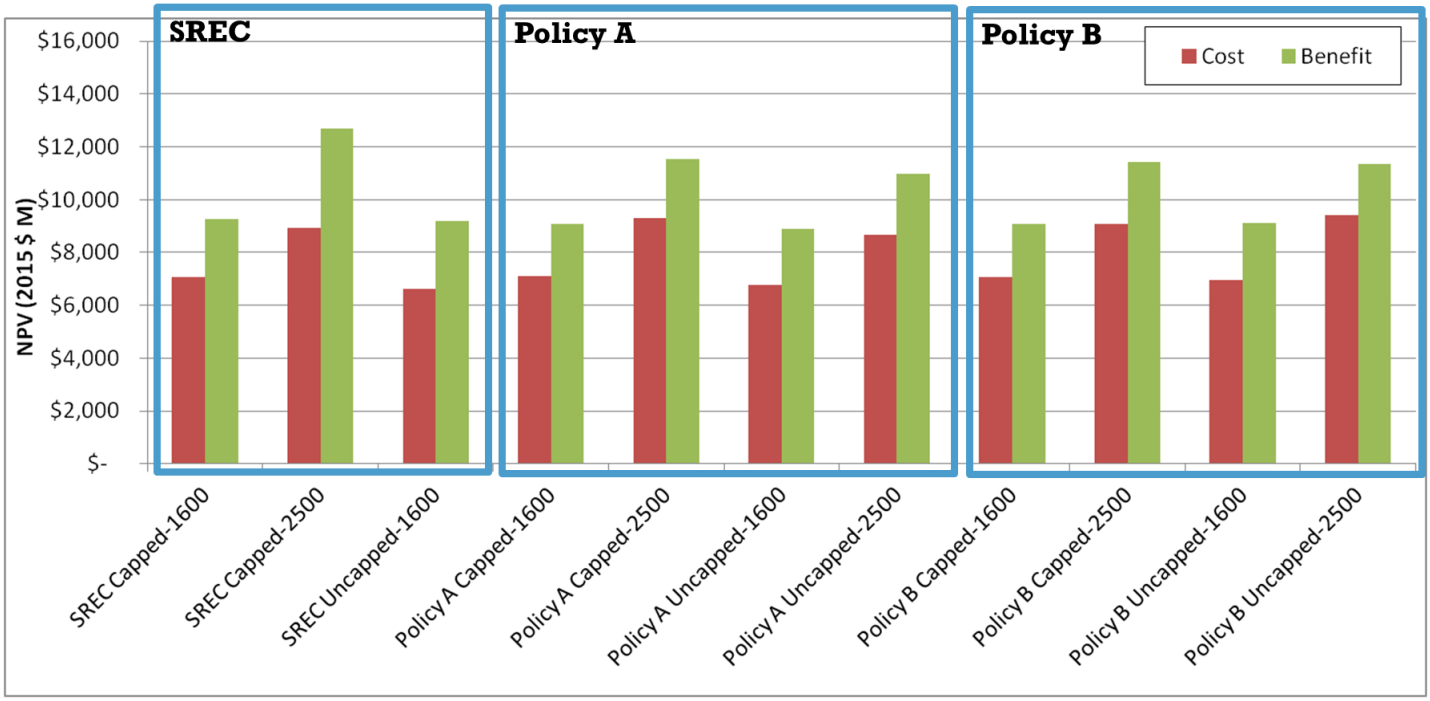
Costs

		2500 MW		1600 MW	
C/B Component ↓	CB Code	NPV Costs (Million $)	NPV$/MWh Costs	NPV Costs (Million $)	NPV $/MWh Costs
System Installed Costs	CB1.1	$ 6,696.8	$ 97.2	$ 5,183.0	$ 118.9
Ongoing O&M + Insurance Costs	CB1.2	$ 1,382.7	$ 20.1	$ 980.3	$ 22.5
Lease Payments	CB1.3	$ 228.2	$ 3.3	$ 209.0	$ 4.8
PILOTs / Property Taxes	CB1.4	$ 152.6	$ 2.2	$ 148.1	$ 3.4
MA Income Taxes	CB1.6.b	$ 87.7	$ 1.3	$ 97.8	$ 2.2
Federal Income Taxes	CB1.7b	$ 383.7	$ 5.6	$ 427.9	$ 9.8
Solar Policy Incr. Admin. & Transaction Costs	CB2.4	$ -	$ -	$ -	$ -
Total		**$ 8,931.6**	**$ 129.7**	**$ 7,046.2**	**$ 161.7**

Figure 41 shows the NPV of total costs and benefits from the CG perspective for each policy future. CG profitability is highest in the

SREC capped to 2500 MW scenario. Total costs to CG are highest in the Policy B uncapped scenario mostly because of higher income taxes in Policy B. The total profit to CG does not vary greatly between Policy A and Policy B, capped and uncapped scenarios. This is because of the more moderate direct incentive benefits CG receive in these policies. Overall, Policy A and B total benefits and costs are similar.

Figure 41: Total NPV Costs & Benefits, CG Perspective



8.3 Total Costs & Benefits, NPR Perspective

The relative costs and benefits to non-participant ratepayers (NPRs) shows the degree of subsidy they are bearing and from which components costs are coming. Table 21 shows the detail NPV costs and benefits from the NPR perspective for the SREC capped policy scenario. Similar tables for additional policy cases can be found in Appendix B. In the current policy, SREC capped to 1600 MW, the total cost to NPRs is about $2.95 billion. More than 50% of the NPR total costs are from direct incentive payments. Other large costs are non-generation components of on-site generation and VNM. Differences in direct incentive costs are one of the largest drivers of overall costs to NPR between policy scenarios.

The largest benefit to NPRs in all policy scenarios is the avoided generation capacity costs at about $2.1 billion, or about 40% of total benefits. Additionally, variance in displaced RPS Class I compliance costs has a small impact on the total benefits to NPRs. More Class I compliance costs are displaced in Policy A and B because each MWh is displaces a full Class I REC whereas in the SREC policy, some MWh produce less than a full SREC (sectors B, C, and D). Avoided environmental impacts are also a significant benefit across all policy scenarios.

Table 21: Comparing NPR Detailed Costs and Benefits – SREC Capped

Benefits

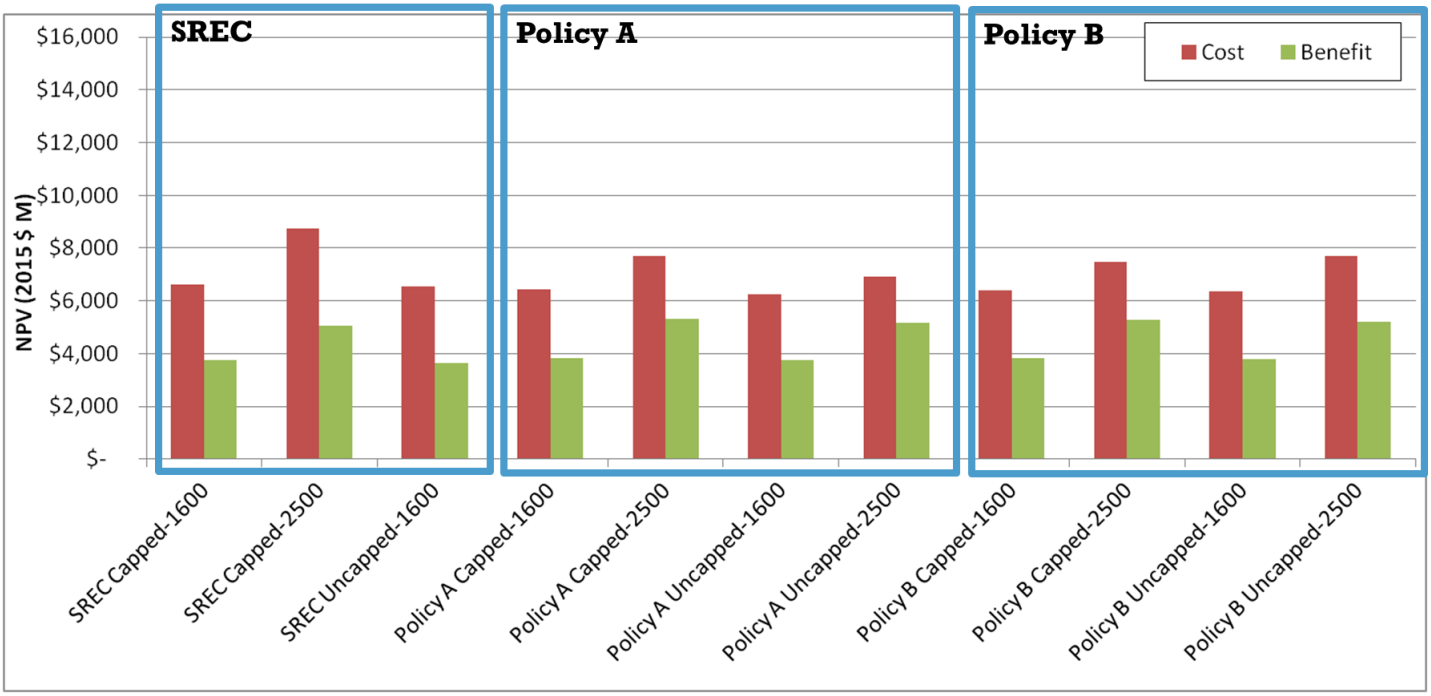
C/B Component ↓	CB Code	2500 MW NPV Benefits (Million $)	2500 MW NPV $/MWh Benefits	1600 MW NPV Benefits (Million $)	1600 MW NPV $/MWh Benefits
MA Income Taxes	CB1.6.b	$ 146.9	$ 2.1	$ 150.1	$ 3.4
Displaced RPS Class I Compliance Costs	CB2.3	$ 1,471.6	$ 21.4	$ 921.8	$ 21.2
Generation Value of On-site Generation	CB3.1	$ 135.1	$ 2.0	$ 58.3	$ 1.3
Wholesale Market Sales	CB4.3	$ 3.9	$ 0.1	$ 2.7	$ 0.1
Wholesale Market Price Impacts - Energy	CB5.1	$ 54.4	$ 0.8	$ 64.4	$ 1.5
Avoided Generation Capacity Costs	CB5.3	$ 2,064.4	$ 30.0	$ 1,551.2	$ 35.6
Avoided Transmission Tariff Charges	CB5.5	$ 167.0	$ 2.4	$ 148.4	$ 3.4
Avoided Trans. Investment - Remote Wind	CB6.1	$ 181.8	$ 2.6	$ 112.5	$ 2.6
Avoided Environmental Impacts	CB7.1	$ 710.8	$ 10.3	$ 660.0	$ 15.1
Total		**$ 4,935.7**	**$ 71.7**	**$ 3,669.3**	**$ 84.2**

Costs

C/B Component ↓	CB Code	2500 MW NPV Costs (Million $)	2500 MW NPV$/MWh Costs	1600 MW NPV Costs (Million $)	1600 MW NPV $/MWh Costs
MA Residential RE Tax Credit	CB1.6.a	$ 134.0	$ 1.9	$ 56.7	$ 1.3
Direct Incentives (e.g., SRECs)	CB2.1	$ 4,884.4	$ 70.9	$ 3,871.4	$ 88.8
Other Solar Policy Compliance Costs (e.g. SACP)	CB2.2	$ 200.0	$ 2.9	$ 175.7	$ 4.0
Solar Policy Incr. Admin. & Transaction Costs	CB2.4	$ -	$ -	$ -	$ -
Transmission Value of On-site Generation	CB3.2	$ 401.7	$ 5.8	$ 181.4	$ 4.2
Distribution Value of On-site Generation	CB3.3	$ 1,074.0	$ 15.6	$ 446.9	$ 10.3
Other Retail Bill Components (Trans., EE, RE)	CB3.4	$ 125.1	$ 1.8	$ 63.1	$ 1.4
Offsetting On-site Usage	CB4.1	$ 182.4	$ 2.6	$ 78.6	$ 1.8
Virtual NM	CB4.2	$ 1,756.2	$ 25.5	$ 1,751.3	$ 40.2
Total		**$ 8,757.8**	**$ 127.1**	**$ 6,625.1**	**$ 152.0**

Figure 42 shows a comparison of the total NPV costs and benefits to NPRs in the different policy scenarios. The largest cost scenario is SREC capped to 2500 because of the magnitude of direct incentive payments in comparison to Policy A and B incentive payments. Benefits to NPRs are similar across policies with the same MW target. The total benefits to NPRs have little variation across policy futures with the same MW target. This observation suggests if the goal is to improve the NPR B:C ratio more emphasis should be put on reducing total costs to NPR than modifying policies to improve benefits.

Figure 42: Total NPV Costs & Benefits, NPR Perspective



8.4 Total Costs & Benefits, C@L Perspective

This section looks at the costs and benefits to the citizens at large (C@L). The conclusions drawn from analysis of the costs and benefits from the C@L perspective is what may or may not justify having a solar policy. Massachusetts citizens at large encompasses all Massachusetts citizens and organizations and is generally a superset of other categories. Table 22 shows the detail NPV costs and benefits from the NPR perspective for the SREC capped policy scenario. Similar tables for additional policy cases can be found in Appendix B. In the current policy, the net benefits to C@L is $5.5 billion. The costs to C@L include federal income taxes, direct incentives, and solar policy administrative and transaction costs. The largest benefits to C@L are system installed costs retained in state, avoided generation capacity costs, and generation value of on-site production. In the current policy, SREC capped to 1600 MW, system installed costs make up about one-fifth of the total benefit to MA C@L, exemplifying that in-state system installed costs are a large driver of overall benefits of solar policy. System installed costs are similar across policy futures. Direct incentive costs are highest to C@L in the SREC capped scenario but more federal taxes in other policy futures reduces the total cost difference among policies.

Table 22: Comparing C@L Detailed Costs and Benefits – SREC Capped

Benefits

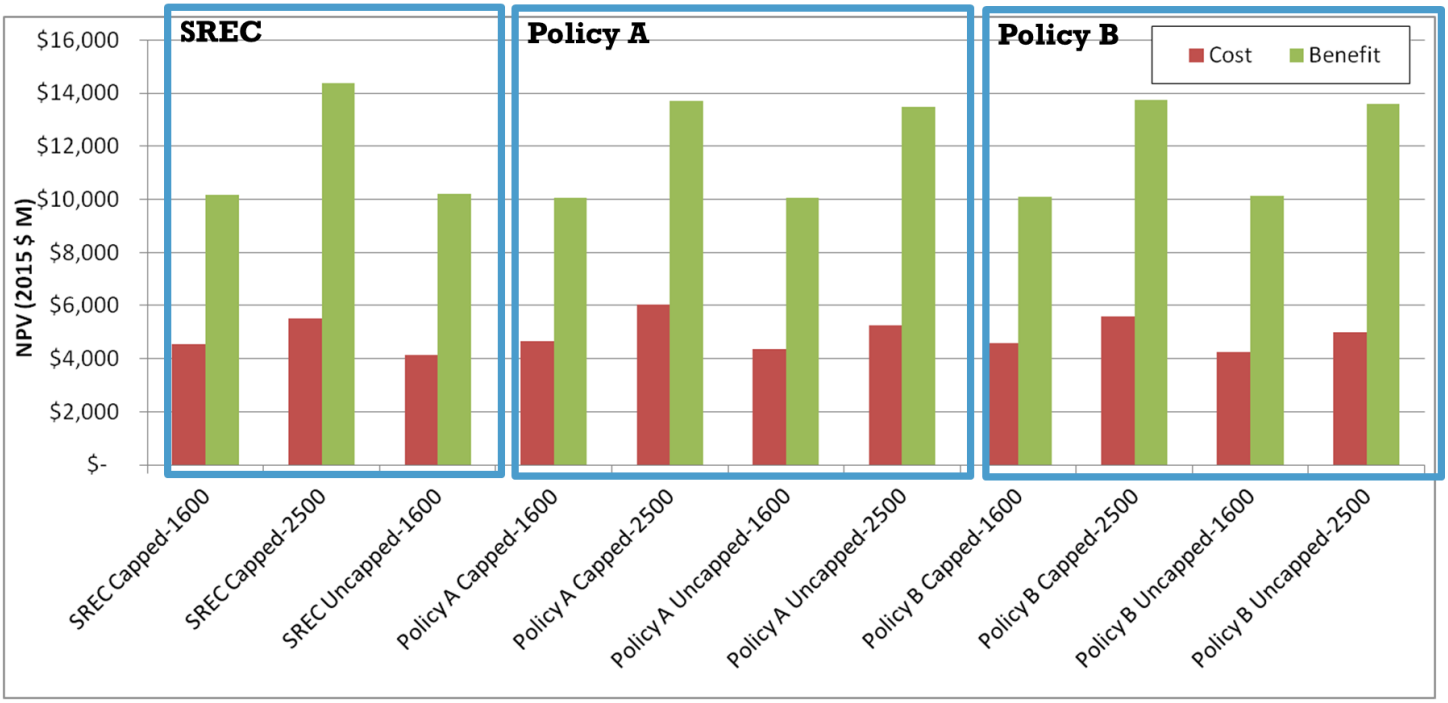
C/B Component ↓	CB Code	2500 MW NPV Benefits (Million $)	2500 MW NPV $/MWh Benefits	1600 MW NPV Benefits (Million $)	1600 MW NPV $/MWh Benefits
System Installed Costs	CB1.1	$ 2,812.6	$ 40.8	$ 2,176.9	$ 50.0
Ongoing O&M + Insurance Costs	CB1.2	$ 884.9	$ 12.8	$ 627.4	$ 14.4
Lease Payments	CB1.3	$ 228.2	$ 3.3	$ 209.0	$ 4.8
PILOTs / Property Taxes	CB1.4	$ 152.6	$ 2.2	$ 148.1	$ 3.4
ROI (Aggregate Return to Debt & Equity)	CB1.5	$ 1,120.9	$ 16.3	$ 667.7	$ 15.3
Federal Incentives (ITC)	CB1.7a	$ 195.7	$ 2.8	$ 188.8	$ 4.3
Displaced RPS Class I Compliance Costs	CB2.3	$ 1,471.6	$ 21.4	$ 921.8	$ 21.2
Generation Value of On-site Generation	CB3.1	$ 2,554.3	$ 37.1	$ 1,102.4	$ 25.3
Other Retail Bill Components (Trans., EE, RE)	CB3.4	$ 14.2	$ 0.2	$ 6.8	$ 0.2
Offsetting On-site Usage	CB4.1	$ 157.0	$ 2.3	$ 62.9	$ 1.4
Virtual NM	CB4.2	$ 1,282.7	$ 18.6	$ 1,287.7	$ 29.6
Wholesale Market Sales	CB4.3	$ 72.9	$ 1.1	$ 51.1	$ 1.2
Wholesale Market Price Impacts - Energy	CB5.1	$ 54.4	$ 0.8	$ 64.4	$ 1.5
Avoided Generation Capacity Costs	CB5.3	$ 2,184.5	$ 31.7	$ 1,629.0	$ 37.4
Avoided Transmission Tariff Charges	CB5.5	$ 167.0	$ 2.4	$ 148.4	$ 3.4
Avoided Trans. Investment - Remote Wind	CB6.1	$ 181.8	$ 2.6	$ 112.5	$ 2.6
Avoided Environmental Impacts	CB7.1	$ 710.8	$ 10.3	$ 660.0	$ 15.1
Total		**$ 14,246.1**	**$ 206.8**	**$ 10,064.8**	**$ 231.0**

Costs

C/B Component ↓	CB Code	2500 MW NPV Costs (Million $)	2500 MW NPV$/MWh Costs	1600 MW NPV Costs (Million $)	1600 MW NPV $/MWh Costs
Federal Income Taxes	CB1.7b	$ 642.5	$ 9.3	$ 656.5	$ 15.1
Direct Incentives (e.g., SRECs)	CB2.1	$ 4,884.4	$ 70.9	$ 3,871.4	$ 88.8
Solar Policy Incr. Admin. & Transaction Costs	CB2.4	$ -	$ -	$ -	$ -
Total		**$ 5,526.9**	**$ 80.2**	**$ 4,528.0**	**$ 103.9**

Figure 43 shows a comparison of the total NPV costs and benefits to C@L in the different policy scenarios. The policy which has the most benefits to C@L is SREC capped to 2500 MW. The total benefits and costs of policies to 1600 MW because the marginal impacts on C@L after truncating SREC-II are small. For policies targeting 2500 MW, capped scenarios have slightly more total benefits to C@L and more total costs to C@L. This is because on-site generation has more generation value to C@L than VNM. This difference is even larger in Policy A because VNM only receives the wholesale value of energy sent to the grid..

Figure 43: Total NPV Costs & Benefits, C@L Perspective



9 Qualitative Discussion of Impacts on Employment and Resiliency

While detailed quantitative analyses of employment impacts and resiliency are beyond the scope of this analysis, these are both issues of importance with respect to potential net benefits of solar in Massachusetts, and they are both discussed in this Section.

9.1 Solar Energy Employment Impacts

9.1.1 Introduction to Solar Jobs in Massachusetts

In its 2014 Massachusetts Clean Energy Industry Report, the Massachusetts Clean Energy Center (MassCEC) estimates that the state solar industry employs just over 12,100 workers (MassCEC, 2014), while the Solar Foundation's national Solar Jobs Census found a similar, but slightly lower number, estimating 9,200 solar jobs in Massachusetts in the same year (The Solar Foundation, 2014). Industry-wide employment figures such as these are useful to understand the total number of Massachusetts workers engaged with solar on a day-to-day basis. However these figures do not reflect the total economic and employment impact of solar in the Commonwealth.

There are a range of different categories of job losses and gains associated with solar project development beyond direct solar employment. The following section provides an estimate of employment impacts derived from project development, and reviews other efforts to analyze jobs impacts. Jobs impacts of any energy policy can vary widely based on the analysis methodologies used and the analysis inputs and assumptions. A macroeconomic analysis of the employment effects of the proposed solar policy options is beyond the scope of this report. Within the framework of the Task 3 analysis, jobs impacts accrue to citizens of Massachusetts at large and do not have directly impact participants or non-participating ratepayers.

9.1.2 Categories of Job Impacts

Solar development has employment impacts that go beyond jobs in the solar industry itself. Economic impact analyses typically categorize economic and employment impacts into three primary groups. These impact categories can have either positive or negative net state-wide job impacts. The job impact categories are:

- **Direct Impacts**. In the context of solar project development, these are jobs that relate directly to the construction and installation, or operations and maintenance, of a solar project. This job impact category has a high likelihood of creating in-state jobs as employers may be unlikely to bring in temporary workers from other states into a stable solar market. Policies that create local boom and bust development cycles, however, may create conditions conducive to bringing in out-of-state crews and thereby reduce this effect.
- **Indirect Impacts.** These refer to fields or industries that support or supply direct economic activity related to the solar industry, such as manufacturing jobs that provide construction materials or various professional services that support construction activities. Some of these job impacts are less likely to be in-state, as there are a limited number of Massachusetts solar system component manufacturers. For some developers with offices in Massachusetts, indirect jobs impacts in the Commonwealth would be higher than for developers with out-of-state offices that serve Massachusetts.
- **Induced Impacts.** These result from increased spending due to new direct and indirect jobs in the state. Induced impacts can also result from utility bill savings or incentive payments, which can create increased economic activity. These impacts would also include associated job losses from industries that see reduced revenues because solar installations (such as existing power plant operators).

Employment impacts are often discussed in terms of job-years, which allows employment impacts of varying types to be compared directly. The creation of ten full-time jobs for one year would have an impact of ten job-years, as would the creation of twenty half-time jobs for one year or the creation of one full-time job for ten years.

9.1.3 Jobs Impacts from Project Development

The National Renewable Energy Laboratory (NREL) has developed a series of Jobs and Economic Development Impact (JEDI) models (NREL, 2015), which provide employment impact estimates of discreet renewable energy projects or project portfolios, including solar PV. JEDI model outputs include direct, indirect, and induced labor and economic impacts. Induced labor impacts in these models only reflect increased spending that results from direct and indirect labor, not from customer energy savings or macroeconomic effects from subsidy payments. These models may be used to provide an estimate of total employment impacts due to solar project development and operation, though the models does not provide a complete picture of the employment impacts of solar development.

Table 23 below summarizes the per-MW employment impacts of project development in Massachusetts found in the NREL JEDI model. The type—or more directly, size—of projects that are built as the Massachusetts solar market continues to develop will have an impact on the magnitude of employment impacts. Large amounts of smaller systems will have larger labor requirements, and therefore larger employment impacts, than a smaller number of larger projects that result in the same total installed capacity.

Table 23: JEDI Job and Economic Impacts per MW from Solar Construction in Massachusetts

		Direct Impacts	Indirect Impacts	Induced Impacts	Total Impacts
Residential Retrofit	Job-Years	12.6	13.9	8.6	35.1
	Economic Output	$1,306,744	$2,601,706	$1,254,690	$5,163,140
Residential New Construction	Job-Years	13.1	12.3	7.5	33.0
	Economic Output	$1,211,691	$2,349,393	$1,101,407	$4,662,491
Small Commercial	Job-Years	8.7	15.6	9.6	33.9
	Economic Output	$1,258,112	$2,776,536	$1,416,989	$5,451,636
Large Commercial	Job-Years	8.3	10.2	6.9	25.4
	Economic Output	$1,187,304	$1,562,838	$1,022,818	$3,772,960
Utility	Job-Years	5.2	4.9	3.7	13.8
	Economic Output	$752,040	$726,279	$553,870	$2,032,189

Based on state data on projects participating in Massachusetts SREC I and SREC II programs (DOER, 2015), 728 MW of solar has come online in Massachusetts since 2008. Using the JEDI jobs factors above,[20] this amount of solar development has created an estimated 14,762 total job-years in the state.[21]

Table 24: Estimated Project-Related Employment Impacts from Massachusetts Solar Development to Date

	MW Installed	Direct Job-Years	Indirect Job-Years	Induced Job-Years	Total Job-Years
Residential	97	1,230	1,356	836	3,422
Small Commercial	26	224	403	249	876
New Commercial	182	1,512	1,852	1,260	4,625
Utility	423	2,178	2,077	1,584	5,839
Total	728	5,145	5,688	3,929	14,762

293 MW of statewide solar capacity was installed in 2014. Using the same jobs factors, these projects created an estimated 5,883 job-years through direct, indirect, and induced employment impacts.

Critically, this analysis does not include potential wider economic impacts of solar development. For instance the overall cost of any SREC or other PBI payments to project owners would be a transfer of value from all ratepayers to specific system owners. The overall jobs impacts of these transfers would depend on how and if these benefits were spent in the Massachusetts economy. Similarly, reduced energy costs for individual utility customers from solar installations also result in benefits and costs flowing both to and from all ratepayers and specific solar system owners. Also solar installations create state-wide economic and job benefits in the form of reduced wholesale energy market prices and avoided environmental compliance costs, however the reduction of power purchases from these systems may create jobs impacts for non-solar power generators that may or may not be located in Massachusetts. (The full range of potential economic costs and benefits of particular solar policy options is discussed elsewhere in this section).

9.1.4 Effects of Policy Options on Jobs Impacts

Solar policy choices will have dynamic effects on overall local job impacts. For instance, policies that favor smaller systems, with greater labor inputs are more likely to result in greater direct job impacts than policies that support large ground mounted systems with lower total labor input. That said, polices that support a higher proportion of smaller systems may result in higher overall incentive requirements, increasing the overall cost of a policy, creating negative induced job impacts as utility customers as a whole see increased charges resulting from higher incentive values. The balance of these costs and benefits would determine the overall net jobs created in a state by these policies.

[20] This analysis assumes that non-residential projects smaller than 50 kW are small commercial projects, projects from 51 to 1000 kW are large commercial projects, and projects over 1 MW are utility-scale projects.

[21] Note that this number cannot be compared directly to the MassCEC's and Solar Foundation's estimates above, which are estimates of the number of workers employed in the solar industry at a given point in time rather than the estimated number of total direct, indirect, and induced job-years in Massachusetts that have been created as a result of solar development in the state.

Additionally, other policy choices may favor the creation of in-state vs. out-of-state jobs. For instance, a number of states have implemented solar incentive policies designed to encourage installation of locally-manufactured solar components. One such policy was implemented by the MassCEC as part of the Commonwealth Solar program, where added incentives were provided for the use of Massachusetts-manufactured system parts. The net impact of these incentive adders, again, depends on the incremental costs of these incentives to ratepayers and the total number of jobs supported in-state by these incremental incentive costs. It may be difficult for states to create permanent in-state manufacturing jobs in the solar industry using these mechanisms as state-level markets may be insufficient to support manufacturing facilities that need to compete with global system component manufacturers.

Finally, the flow of benefits both in and out of the state will depend on the nature of entities installing systems in the state. For instance, small local installer may have all their employees in-state, including system designers, sales staff and back-office employees. Policies that create market growth that supports these firms over larger national firms, with many of the above listed functions performed out-of-state, could lead to greater local job impacts. Again, this effect could be reduced if local firms have higher overall cost structures that require higher incentives, leading to greater overall policy costs to ratepayers. Some states, such as Delaware, have provided incentive adders for the use of in-state installation firms. The overall effects of these adders has not been analyzed and would require substantial macroeconomic analysis in order to determine whether these bonus incentives resulted in net job benefits.

9.2 Resiliency Impacts

Resilient solar, a term used to describe solar with off-grid capabilities, can provide services to both the host-customer, surrounding community and the grid. Cities across the United States have deployed resilient solar in their emergency planning processes. Community centers and critical infrastructure with resilient solar have continued to operate during emergencies, and business models have emerged using the value stream provided by ancillary services by these installation. This section highlights the benefits of resilient solar in several categories and the effects of these costs and benefits on customer generators and citizens of Massachusetts at large.

9.2.1 Host Sites and Community Resilience

In the event of an outage, resilient solar installations are able to provide long-term power supply for critical loads by leveraging a battery backup system. Many critical facilities in the community, such as hospitals and public safety facilities, already maintain backup generators that allow for continued, if limited, operations in the event of a power outage. However, in the event fuel is unable to be delivered, these diesel generators will only serve a host facility as long as there is available fuel supply. Resilient solar systems can be installed in tandem with existing backup generators to reduce fuel consumption, thereby increasing the total amount of time the facility can run disconnected from the grid.

Recognizing this benefit, a number of local governments have pursued resilient solar installations for critical facilities. For instance, the City of Baltimore has integrated resilient solar into its Disaster Preparedness and Planning (DP3) for hospitals, shelters and other critical facilities in recognition of the unique benefits provided by resilient solar, while Boston has utilized off-grid solar along key evacuation routes as part of its emergency preparedness process.

To date, efforts to quantify the impacts of the back-up capacity value of resilient solar at a large scale have been limited as the specific context of each installation is unique and dependent on local electricity market factors. For instance the incremental benefits of a resilient solar installation may be personally substantial for a homeowner with a system that is able to operate during a lengthy power outage; however, the economic value to both the homeowners and citizens of the Commonwealth at large is difficult to quantify. Similarly, the cost and benefits of a resilient solar facility on a private-sector property would depend on the likelihood of

a number of factors including the potential economic losses from a power failure along with the likelihood that business operations could be sustained in the event of a local power failure, even if power to the facility is maintained.

Critical community facilities with life and health safety obligations, such as hospitals, community shelters and public safety facilities may be appropriate sites for resilient solar installations as the consequences of power outages at these sites could include potentially life threatening situations. For these types of installations, the benefits of resilient solar installations accrue to both the facility owners and to the public at large as these sites can maintain operations that support their communities during an emergency. The full value of this benefit would be challenging to quantify for a range of reasons including the fact that many critical community facilities such as hospitals typically have backup generators that allow for limited off-grid operations, and that resilient solar installations provide redundancy to those already-existing systems.

9.2.2 Ancillary Grid Services – Demand Response, Frequency Regulation and Increased Renewables Grid Integration Capacity

Solar and wind are intermittent resources, and their electricity supplied to the grid can vary significantly based on short-term weather conditions. Batteries lower this intermittency by providing power even if system output changes in response to changing weather conditions. Solar installations with battery backups create distributed generators which can behave as a dispatchable resource. Battery power can also be used to provide demand response at the host facility or to participate in frequency regulation markets if the installation has an inverter to distinguish between serving on-site load, the grid or critical loads. There is currently a 2.5 MW solar microgrid in Vermont with 4MW of storage, which participates in the frequency regulation market of ISO New England.

These additional value streams may be a significant future driver for resilient solar installations. SolarCity, one of the largest PV installers in the United States, recently commented that they are regularly providing commercial customers affected by demand charges with financially viable project proposals that integrate battery backup systems (Wessoff, 2015). As both solar and battery costs continue to decline, the deployment of cost-effective resilient solar installations that provide off-grid operational capacity along with other benefits could substantially change the Massachusetts PV market.

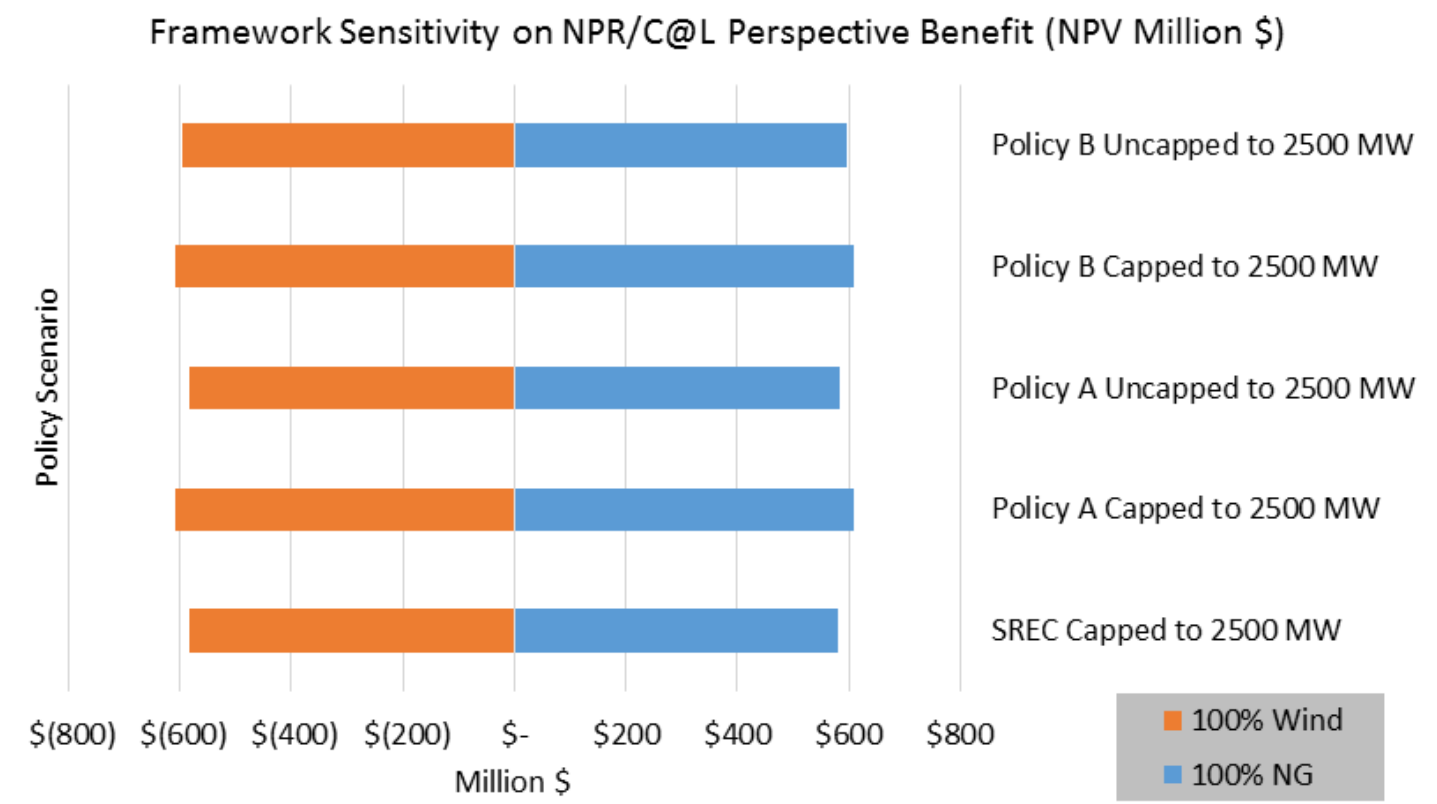
The ancillary grid services provided by resilient solar installations can result in benefits for both customer generators and the citizens of Massachusetts at large. If customer generators are able to monetize a portion of the benefits described above, the system's benefits may outweight the additional costs associated with resilient solar installations. Similarly, by providing grid support services such as demand response and frequency regulation capabilities, resilient solar may be able to provide grid services at a lower cost than could be provided by alternative sources. The full stream of costs and benefits and how they might accrue within the wider electricity market will likely be highly dynamic and dependent the specifics of how the electricity market in New England evolves over the coming years. Additionally, if policies provide additional incentives for resilient solar installations, any benefits which might accrue to the citizens of Massachusetts at large from these installations would be netted against the added costs associated with incentivizing these systems.

10 Sensitivity Analyses

10.1 Sensitivity to Selected Class I RPS Carve-out Framework

As discussed in Section 1.3, the results presented herein are based on an assumed 50%/50% weighting of the two bounding assumptions of solar PV substitution impact, displacing onshore wind in the event sufficient wind supply is developable to meet Class I RPS demand, and displacing natural gas in the event insufficient wind could be developed and the Class I RPS would fall short, In this section, we test the sensitivity of the results to this assumption by calculating results based on either extreme. Only two perspectives were impacted by this choice, NPR and C@L. Impacts are volume-sensitive, not policy-sensitive. The results of this sensitivity analysis are shown in Figure 44. As can be seen, the maximum variation in these assumptions can vary the total Benefits to each perspective of about NPV $$600 million.

Figure 44: Framework Sensitivity Analysis Results



10.2 Parametric Sensitivity Analyses

As described in Section 4.1.3, a number of factors, or parameters, were developed or assumed for this analysis that are subject to a degree of uncertainty. For each of the parameters described in Table 25, a 'base' assumption was developed, but in addition, the sensitivity of the results to variations in the selected assumption were also explored. Where data was available, the base parameters were developed based on available public sources and supplemental literature research. For other assumptions, the base value represents an educated parametric estimate.

Table 25: Summary of Parameters used in Analysis

		Parameter	Selected Parameter	Selected Value	Base	Sensitivity	Description
System Installed Costs	CB1.1	A	Base	42%	42%	52.0%	% of System Installed Cost Expenditures Retained In-State
Ongoing O&M + Insurance Costs	CB1.2	A	Base	64%	64%	74.0%	% of Ongoing O&M & Insurance Cost Expenditures Retained In-State
ROI (Aggregate Return to Debt & Equity)	CB1.5	A	Base	30%	30%	40.0%	% of Return to Debt & Equity Investors Retained In-State
Federal Incentives (ITC)	CB1.7a	A	Base	15%	15%	25.0%	% of Federal ITC retained in-state (assume same as CB1.1-A)
Avoided Generation Capacity Costs	CB5.3	A	Base	28.8%	28.8%	38.8%	Fraction of solar PV monetizing its value in the FCM; [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%
Avoided Trans. Investment - Remote Wind	CB6.1	A	Base	$ 27.50	$ 27.50	$ 35.00	$/MWh Incremental TX cost for Northern New England wind avoided by supplanting need for Class I wind with MA Solar PV
Avoided Trans. Investment - Remote Wind	CB6.1	B	Base	55%	55%	80%	% of incremental TX cost for Northern New England Wind assumed allocated to load
Avoided Transmission Investment - Local	CB6.2	A	Base	30%	30.0%	40.0%	% of load on feeders with growth
Avoided Transmission Investment - Local	CB6.2	B	Base	80%	80.0%	90.0%	Scalar Adjustment Factor for technical issues (reduces gross value to account for a variety of technical issues preventing solar PV from avoiding investment deferral
Avoided Distribution Investment	CB6.3	A	Base	30%	30.0%	40.0%	% of load on feeders with growth
Avoided Distribution Investment	CB6.3	B	Base	50%	50.0%	60.0%	Scalar Adjustment Factor for technical issues (reduces gross value to account for a variety of technical issues preventing solar PV from avoiding investment deferral
Avoided Distribution Investment	CB6.3	C	Base	50%	50.0%	60.0%	Scalar derating factor applied to distribution level energy losses avoided by solar PV, to reflect that the D investment is at varying locations often close to load, while aggregate D losses measured at D system injection; also reflects that some of literature review sources were already loss adjusted

To test the magnitude of impact of each parameter, a parametric sensitivity analysis was be conducted. Table 26 summarizes the results of a +10% sensitivity analysis for each parameter for Policy Path A to 2500 MW (Uncapped).[22] The change in NPV (measured in $million) from the base case for each perspective is summarized in the table. The values in columns "C" represent the difference in NPV of costs and the values in columns "B" represent the difference in NPV of benefits from each perspective shown. A positive value indicates an increase in NPV from the base case, while a negative value indicates a reduction in NPV from the base case. During the parametric sensitivity analysis, only one parametric sensitivity was tested at a time , with all other assumptions held constant. The value of a 10% parametric assumption analysis with a linear scalar input assumption is that it is easy to do the mental math to adjust the result to any level of variation. For a purely illustrative example, if one believes that the percent of system installed costs should be 20% higher than the base assumption, one could double the result to understand the potential impact of varying this parameter.

As shown below, a +10% sensitivity would not impact the cost side of the analysis for any of the four perspectives (not a surprise, as the calculation of benefits for these factors tends to be more uncertain then the more readily calculated benefits). Non-owner participants would also not be affected by the sensitivities. Increasing the fraction of solar PV monetizing its value in the FCM by 10% would increase the benefits to customer generators. Further, increasing any PV system cost parameters or the fraction of solar PV monetizing its value in the FCM by 10% would reduce the benefits to non-participating ratepayers, but increase the benefits to the Commonwealth at large. Lastly, higher electric investment impact parameters (except the scalar derating factor applied to distribution level energy losses avoided by solar PV) would result in greater benefits to both non-participating ratepayers and the C@L at the same rate. Increasing the scalar derating factor applied to distribution level energy losses avoided by solar PV would, on the other hand, result in less benefits to those two perspectives. This analysis suggests that the parameters for which the benefit

[22] For one set of parameters, a figure different from 10% was selected: The two parameters related to Avoided Transmission Investment – Remote Wind were explored with alternative assumptions representing a larger spread based on a recent proprietary analysis performed by Sustainable Energy Advantage, LLC.

calculations are most sensitive include the percent of system installed costs assumed retained in state, and the percent of the aggregate return to debt and equity investors retained in state.

Table 26: Parametric Sensitivities (Policy Path A to 2500 MW Uncapped), NPV Million $

		Parameter	Selected Parameter	Selected Value	Base	Sensitivity	NOP		CG		NPR		C@L	
							C	B	C	B	C	B	C	B
System Installed Costs	CB1.1	A	Sensitivity	52.0%	42%	52.0%	$ -	$ -	$ -	$ -	$ -	($1.86)	$ -	$621.82
Ongoing O&M + Insurance Costs	CB1.2	A	Sensitivity	74.0%	64%	74.0%	$ -	$ -	$ -	$ -	$ -	($1.86)	$ -	$86.07
ROI (Aggregate Return to Debt & Equity)	CB1.5	A	Sensitivity	40.0%	30%	40.0%	$ -	$ -	$ -	$ -	$ -	($1.86)	$ -	$227.69
Federal Incentives (ITC)	CB1.7a	A	Sensitivity	25.0%	15%	25.0%	$ -	$ -	$ -	$ -	$ -	($1.86)	$ -	$131.85
Avoided Generation Capacity Costs	CB5.3	A	Sensitivity	38.8%	28.8%	38.8%	$ -	$ -	$ -	$41.33	$ -	($43.18)	$ -	$10.54
Avoided Trans. Investment - Remote Wind	CB6.1	A	Sensitivity	$ 35.00	$ 27.50	$ 35.00	$ -	$ -	$ -	$ -	$ -	$47.65	$ -	$47.65
Avoided Trans. Investment - Remote Wind	CB6.1	B	Sensitivity	80%	55%	80%	$ -	$ -	$ -	$ -	$ -	$80.66	$ -	$80.66
Avoided Transmission Investment - Local	CB6.2	A	Sensitivity	40.0%	30.0%	40.0%	$ -	$ -	$ -	$ -	$ -	$9.50	$ -	$9.50
Avoided Transmission Investment - Local	CB6.2	B	Sensitivity	90.0%	80.0%	90.0%	$ -	$ -	$ -	$ -	$ -	$2.40	$ -	$2.40
Avoided Distribution Investment	CB6.3	A	Sensitivity	40.0%	30.0%	40.0%	$ -	$ -	$ -	$ -	$ -	$20.14	$ -	$20.14
Avoided Distribution Investment	CB6.3	B	Sensitivity	60.0%	50.0%	60.0%	$ -	$ -	$ -	$ -	$ -	$14.70	$ -	$14.70
Avoided Distribution Investment	CB6.3	C	Sensitivity	60.0%	50.0%	60.0%	$ -	$ -	$ -	$ -	$ -	($1.62)	$ -	($1.62)

11 Fuel Use and Emission Reductions

11.1 Fuel Usage Reductions

Figure 45 and Figure 46 show the amount of natural gas, oil and coal displaced by 1600 MW and 2500 MW of solar capacity. In both cases, it is assumed that Massachusetts solar would displace natural gas until 2018. Starting from 2018, Figure 45 assumes solar would displace wind under RPS Class I in the absence of a solar carveout policy. Figure 46 assumes solar would instead be displacing natural gas assuming there is not enough wind developed to meet the Class I compliance from 2018 onward. As shown in the graphs, the second framework would result in a larger fuel use reduction impact of solar. Interestingly, the deployment of 2500 MW of solar capacity would lead to a slight increase in oil use under the carveout-successful framework.

Figure 45: Fuel Use Reductions under Carveout-Successful Framework

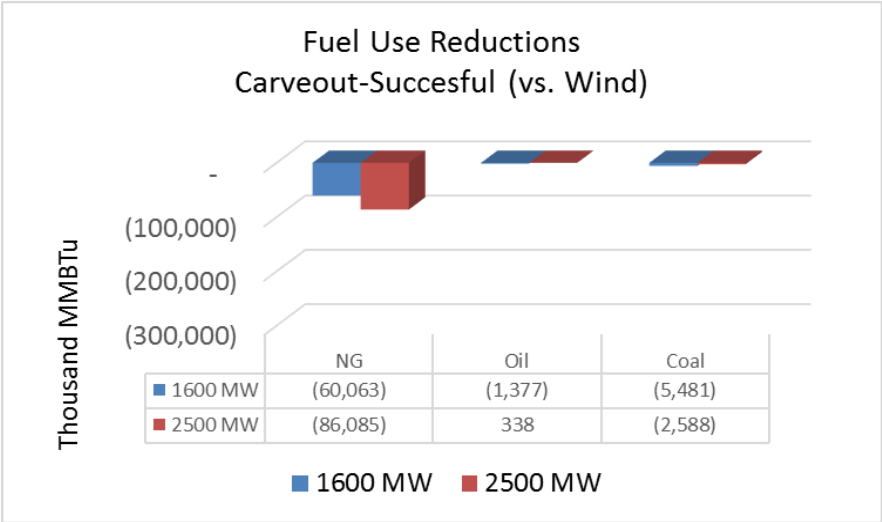
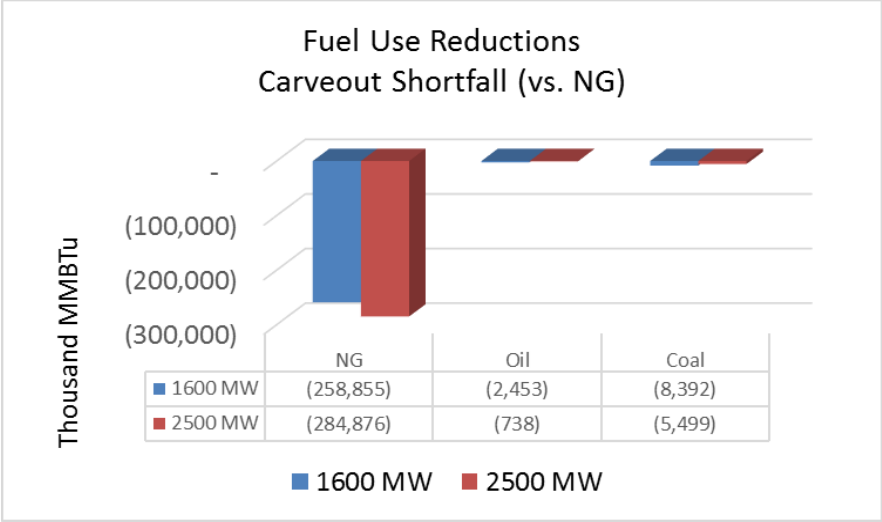


Figure 46 – Reductions under Carveout Shortfall Framework



11.2 Emissions Reductions

The following graphs represent the amount of NO_X, SO_2 and CO_2 displaced by 1600 MW and 2500 MW of solar capacity. Both graphs assume Massachusetts solar would be displacing natural gas until 2018. After 2018, Figure 47 assumes solar would continue to displace RPS Class I compliance met by wind in the absence of a solar carveout policy. Figure 48 assumes Massachusetts is unable to develop enough wind to meet its RPS Class I compliance starting 2018. As a result, Massachusetts solar would displace natural gas. As shown below, solar would have a greater emissions reduction impact under the second scenario.

Figure 47: Emissions Reductions under Carveout-Successful Framework

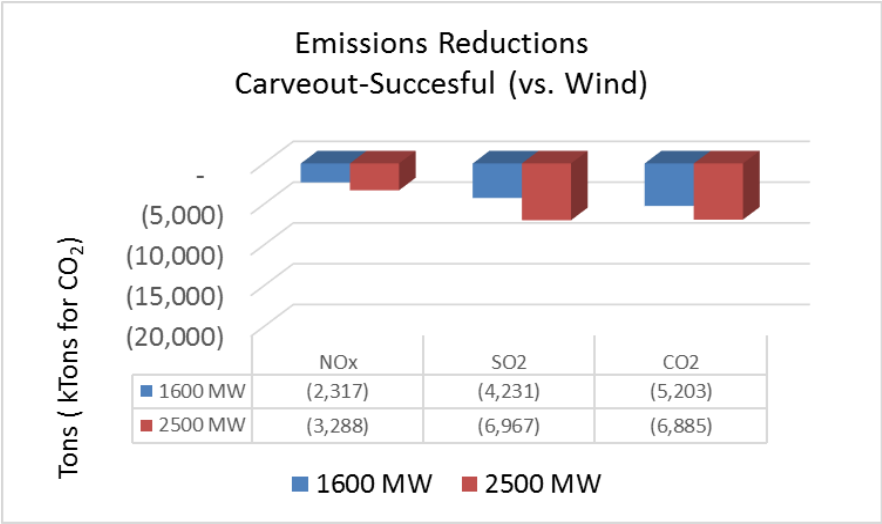
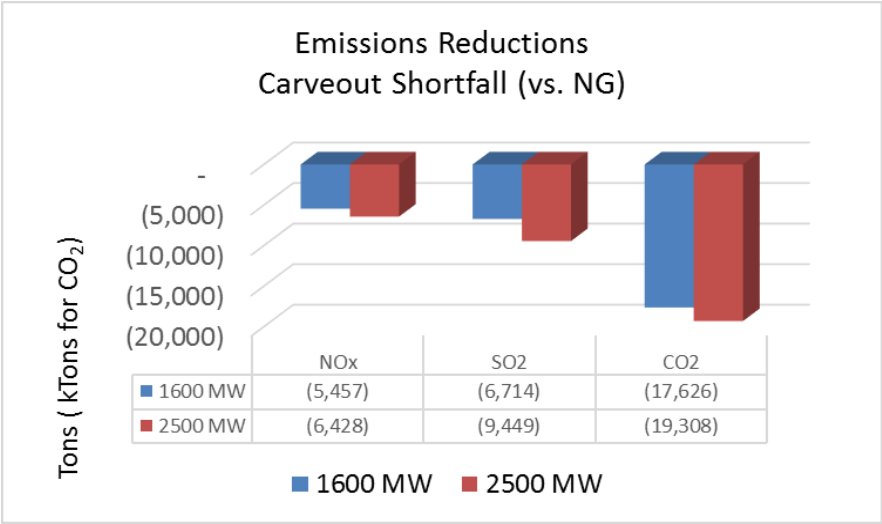


Figure 48: Emissions Reductions under Carveout Shortfall Framework



12 Conclusions and Key Take-Aways

This section compares the quantified cost and benefit across policy scenarios, focusing on the 2500 MW scenarios. It first provides some caveats when comparing results across policy scenarios and then with this context presents and compares the results.

12.1 Comparison of Quantified Cost and Benefit Results across Policy Scenarios

Table 27 through Table 29 presents the NPV of costs and benefits for each policy scenario. A benefit to cost **(B:C)** ratio is derived for each perspective under each policy scenario. The ratio illustrates the trade-off between the cost and benefit to a perspective under each policy. A ratio larger than 1 indicates that the benefit to the perspective is greater than the cost. The higher the ratio, the greater the benefit compared to the policy's cost. The B:C ratio can help inform which policy scenario may be preferred by a perspective. Where multiple policy paths have similar B:C ratios for a particular perspective, a preference among may be driven by other objectives.

In addition to the perspective-specific B:C ratio, another metric - Net Benefits to Citizens at Large to Net Costs to Non-Participating Ratepayers ratio **(NB(C@L):NC(NPR))** ratio - is also derived for each policy scenario. While not a traditional cost and benefit analysis metric, contrasting the ratios across policy scenarios can quantitatively answer the question "which future justifies the subsidy paid by non-participating ratepayers with the greatest net benefits to the Commonwealth at large?" Together the B:C ratio and the NB(C@L):NC(NPR) ratio can be used to identify preferred policies from a benefit/cost perspective. All else being equal, the larger this ratio the stronger the justification the benefits to the Commonwealth justify additional burden on the NPRs. As such, substantial B:C ratios and a high NB(C@L):NC(NPR) ratio can highlight preferred outcomes. It should be noted that while not all costs and benefits are quantified in this analysis, and there are other objectives (such as cost-effectiveness, jobs, diversity of installation types and beneficiaries) to weigh and balance, all else equal, the higher the ratio, the more preferable a policy is to the Commonwealth at large.

12.1.1 Non-Owner Participants (NOPs)

As shown below, the benefit to non-owner participants significantly increase under the alternative policies (to 2500 MW) when net metering caps are removed. The B:C ratios for non-owner participants are 6.27 and 6.17 under Policy Path A (Uncapped) and Policy Path B (Uncapped) respectively. This significant shift is primarily driven by the availability of net metering incentives, which facilitates market participation by non-owners. Without net metering incentives (capped scenario), non-host-owned models, such as Community Shared Solar and low-income housing projects with virtual net metering, would no longer be viable once the net metering caps are reached. Compared to the SREC policy, both alternative policy paths (when uncapped) provide greater support for Community Shared Solar and low-income housing projects as they are more competitive than smaller-scale projects within Sector A. Between the two alternative policies, Policy A has the lower NPV of costs to NOPs. This is a result of a large share of Community Shared Solar and low-income housing projects, which drive down the tax costs to non-owner participants. Although Policy Path A 2500 MW (Uncapped) has a lower NPV of benefits compared to Policy Path B, when balanced with the low NPV of cost, Policy Path A ends up with a slightly higher B:C ratio. However, the Policy Path A and Policy Path B B:C ratios are similar enough that other factors not quantified in this analysis may swing non-owner participants' preference.

12.1.2 Customer Generators

Across all policy scenarios, SREC proves to be the most beneficial policy path for customer generators. The SREC (Capped) scenario has the highest B:C ratio (1.42) for customer generators among all cases. While moving away from SREC is shown to be less profitable for customer generators, the B:C ratios are still above 1 across all policy scenarios. Any of these policies are designed to provide enough gross margin to meet threshold returns; if it is modeled as built, then it is view as financially viable by the CG.

Not surprisingly, the removal of net metering incentives under a capped scenario would lower the margins as shown across all policies. The B:C ratios, however, do not vary largely across capped and uncapped scenarios, which indicates that the existence of net metering is a much smaller factor to customer generators (in aggregate) than to non-owner participants (in aggregate).

12.1.3 Non-Participating Ratepayers

Non-participating ratepayers receive less than 1 B:C ratio across all policy scenarios. This is not surprising, as it simply demonstrates that there is a subsidy for solar, which is getting paid by non-participating ratepayers. When moving away from the SREC scenario, the B:C ratio increases. This is driven by both lower NPV of costs and higher NPV of benefits under the alternative policies. As reflected in the NPV of costs, Policy Path A and Policy Path B require less non-participating ratepayer subsidy to build the same amount of solar than the SREC policies.

Policy Path A (Uncapped) has the highest B:C ratio (0.75) across all alternative

Caveats for Result Interpretation

Although the results contained in this report have been rigorously vetted, some caution should be taken in interpreting the results across different scenarios (i.e., Capped and Uncapped), and also across different Policy Path options (i.e., Policy Path A v. Policy Path B.). Below are description of several major assumptions/modeling artifacts that can somewhat obfuscate such cross-comparison.

- **The modeling overstates the cost-effectiveness of Policy Path Uncapped future** as is described in detail in Section 6.4.
- **Lack of Technical Capacity in Path A, Sector A-Large, Capped**: This factor affects comparison of Path A and Path B Capped Scenarios, and comparison of Path A Capped and Uncapped scenarios. Under Path A, Capped Sector A (without CSS and VNM LIH projects), simply does not have the technical potential to hit the originally planned 25% of aggregate program goal target. In order to hit a 10% target, very high incentive levels (+$600/MWh, more than double Sector B, C, & MG), had to be initially set. A different, lower target would lower comparative costs.
- **Lost Technical Capacity, as a Result of No Negative Bid Assumption:** This factor affects comparison of Path A and Path B Capped Scenarios. Under Path A, the model assumes that a bidder cannot bid lower than the projected Levelized 15-yr value of Rate-Based Incentives ("Rate Values"). This means that, at a certain point (where marginal bid intersects with rate Values), projects in certain utilities are foreclosed from being able to effectively compete in the auction. This in turn can distort results, as resource potential associated with supply curve 'blocks' in utilities with high retail per kWh rate values are "lost", requiring the model to move further down the supply stack (increasing costs) to hit solicitation quotas. In reality, this "lost" technical capacity would likely simply migrate to another utility.
- **Volatility, Costs, and Interaction with Open-Enrollment v. Quota (Solicitation) Based Programs**: Under the solicitation based program (Path A-Large), the number of MWs which successfully bid in each quarterly solicitation can be volatile. This volatility is primarily a result of Failure Rates (which lend to needs for additional installs in subsequent years), as well as "Price is Right" type installation assumptions (which rolls any unsolicited MW into the next quarters solicitation). This in turn means that costs can actually increase quarter to quarter (even though COE is declining), as the EDC would have to move further up the supply curve to hit quotas. In practice, such effects are likely to be more muted than the modeled results. Although the DBI/PBI and EPBI Programs also experiences volatility in MW installs quarter to quarter, because the these programs are not "quota" based (and incentives are fixed), this volatility does not have the same impacts on incentive costs that it does under the solicitation approach (i.e., Path A Large).

policy scenarios, followed by Policy Path B (Capped) (0.71), then Policy Path A (Capped)(0.69) and Policy Path B (Uncapped)(0.68). This outcome demonstrates Policy Path A's ability to build the most cost-effective mix of projects when net metering is available. Without net metering, a larger share of residential and building-mount projects will dominate the market, increasing the per-unit cost to get solar built. This explains why Policy Path A (Capped) has the highest NPV of costs among the four alternative policy scenarios.

The impact of net metering availability is reversed under Policy Path B. This is because a portion of Sector A allocation is redistributed to other more cost-effective sectors when community shared solar and virtual net metered low-income housing projects are no longer viable in the absence of net metering incentives (capped scenario). The cost to build solar is therefore lower under the capped scenario than under the uncapped scenario, while the NPV of benefits are similar for both the capped and uncapped scenarios.

12.1.4 Citizens of the Commonwealth at Large

The B:C ratios for the Commonwealth at large are similar across all policy scenarios, ranging between 2.3 and 2.7. Policy Path A (Capped) has the lowest ratio. This is a result of higher incentive costs and administrative fees driven by a larger market share of smaller and more expensive residential and building-mounted projects in the absence of net metering incentives. SREC policy has the highest NPV of benefits, although it is offset by a relatively high NPV of costs due to the high incentive required to build solar under the SREC program. The NPV of benefits are similar across the alternative policy scenarios. Since Policy Path B (Uncapped) has the lowest NPV of costs driven by a more cost-effective market share of solar installations, it has the highest B:C ratio and may be the preferred policy path for the Commonwealth at large perspective.

Table 27: Quantified Cost and Benefit Results and Ratio by Perspectives: SREC

SREC Capped		2500 MW NPV	1600 MW NPV
NOP	NPV of Costs	$ 318.0	$ 280.9
NOP	NPV of Benefits	$ 1,127.1	$ 1,015.0
	B:C Ratio	3.54	3.61
CG	NPV of Costs	$ 8,931.6	$ 7,046.2
CG	NPV of Benefits	$ 12,668.0	$ 9,271.7
	B:C Ratio	1.42	1.32
NPR	NPV of Costs	$ 8,757.8	$ 6,625.1
NPR	NPV of Benefits	$ 5,047.8	$ 3,766.2
	B:C Ratio	0.58	0.57
C@L	NPV of Costs	$ 5,526.9	$ 4,528.0
C@L	NPV of Benefits	$ 14,358.2	$ 10,161.7
	B:C Ratio	$ 2.6	$ 2.2
NB(C@L):NC(NPR) Ratio		2.38	1.97

SREC Uncapped		2500 MW NPV	1600 MW NPV
NOP	NPV of Costs	#N/A	$ 284.9
NOP	NPV of Benefits	#N/A	$ 1,072.5
	B:C Ratio	#N/A	3.76
CG	NPV of Costs	#N/A	$ 6,631.2
CG	NPV of Benefits	#N/A	$ 9,168.5
	B:C Ratio	#N/A	1.38
NPR	NPV of Costs	#N/A	$ 6,559.9
NPR	NPV of Benefits	#N/A	$ 3,648.7
	B:C Ratio	#N/A	0.56
C@L	NPV of Costs	#N/A	$ 4,145.4
C@L	NPV of Benefits	#N/A	$ 10,187.5
	B:C Ratio	#N/A	$ 2.5
NB(C@L):NC(NPR) Ratio		#N/A	2.08

Table 28: Quantified Cost and Benefit Results and Ratio by Perspectives: Policy Path A

Policy A Capped		2500 MW NPV	1600 MW NPV
NOP	NPV of Costs	$ 340.4	$ 279.0
NOP	NPV of Benefits	$ 1,239.3	$ 1,013.3
	B:C Ratio	3.64	3.63
CG	NPV of Costs	$ 9,312.3	$ 7,102.7
CG	NPV of Benefits	$ 11,540.0	$ 9,070.2
	B:C Ratio	1.24	1.28
NPR	NPV of Costs	$ 7,702.9	$ 6,451.3
NPR	NPV of Benefits	$ 5,316.3	$ 3,838.6
	B:C Ratio	0.69	0.60
C@L	NPV of Costs	$ 6,035.8	$ 4,667.9
C@L	NPV of Benefits	$ 13,721.1	$ 10,070.8
	B:C Ratio	$ 2.3	$ 2.2
NB(C@L):NC(NPR) Ratio		3.22	2.07

Policy A Uncapped		2500 MW NPV	1600 MW NPV
NOP	NPV of Costs	$ 196.8	$ 263.2
NOP	NPV of Benefits	$ 1,233.2	$ 1,008.0
	B:C Ratio	6.27	3.83
CG	NPV of Costs	$ 8,670.5	$ 6,763.3
CG	NPV of Benefits	$ 10,966.0	$ 8,902.6
	B:C Ratio	1.26	1.32
NPR	NPV of Costs	$ 6,927.9	$ 6,256.5
NPR	NPV of Benefits	$ 5,178.0	$ 3,768.9
	B:C Ratio	0.75	0.60
C@L	NPV of Costs	$ 5,271.6	$ 4,347.5
C@L	NPV of Benefits	$ 13,486.0	$ 10,051.7
	B:C Ratio	$ 2.6	$ 2.3
NB(C@L):NC(NPR) Ratio		4.69	2.29

Table 29: Quantified Cost and Benefit Results and Ratio by Perspectives: Policy Path B

Policy B Capped		2500 MW NPV	1600 MW NPV
NOP	NPV of Costs	$ 337.5	$ 277.7
NOP	NPV of Benefits	$ 1,231.0	$ 1,010.3
	B:C Ratio	3.65	3.64
CG	NPV of Costs	$ 9,058.4	$ 7,059.2
CG	NPV of Benefits	$ 11,420.4	$ 9,057.2
	B:C Ratio	1.26	1.28
NPR	NPV of Costs	$ 7,488.5	$ 6,409.7
NPR	NPV of Benefits	$ 5,282.0	$ 3,833.0
	B:C Ratio	0.71	0.60
C@L	NPV of Costs	$ 5,606.2	$ 4,590.7
C@L	NPV of Benefits	$ 13,753.8	$ 10,080.9
	B:C Ratio	$ 2.5	$ 2.2
NB(C@L):NC(NPR) Ratio		3.69	2.13

Policy B Uncapped		2500 MW NPV	1600 MW NPV
NOP	NPV of Costs	$ 245.7	$ 285.0
NOP	NPV of Benefits	$ 1,516.6	$ 1,070.8
	B:C Ratio	6.17	3.76
CG	NPV of Costs	$ 9,423.8	$ 6,947.4
CG	NPV of Benefits	$ 11,342.9	$ 9,117.4
	B:C Ratio	1.20	1.31
NPR	NPV of Costs	$ 7,687.9	$ 6,376.9
NPR	NPV of Benefits	$ 5,218.0	$ 3,780.1
	B:C Ratio	0.68	0.59
C@L	NPV of Costs	$ 4,989.0	$ 4,263.7
C@L	NPV of Benefits	$ 13,584.5	$ 10,120.1
	B:C Ratio	$ 2.7	$ 2.4
NB(C@L):NC(NPR) Ratio		3.48	2.26

12.1.5 Comparing Policy Scenarios

Among the six policy scenarios, Policy Path A (Uncapped) has the highest B:C ratios for two perspectives (non-owner participants and non-participating ratepayers). Additionally, Policy Path A (Uncapped) also has the highest NB(C@L):NC(NPR) ratio (4.69) across all scenarios. This results from a relatively low NPV of costs to non-participating ratepayers driven by competitive solicitation with the support of net metering incentives. Following Policy Path A (Uncapped), Policy Path B (Capped) and Policy Path B (Uncapped) have the second and third highest NB(C@L):NC(NPR) ratios. The SREC (Capped) scenario has the lowest NB(C@L):NC(NPR) ratio among all six policy scenarios.

We are hesitant to pick a preferred policy path for a number of reasons:

1. As discussed above the modeling leads to some culling of some over-incented projects and thus improving the B:C ratios (again see Section 6.4) for the Policy Path A (Uncapped) which artificially improves its NB(C@L):NC(NPR) ratio compared to the other scenarios.
2. All the other caveats described in the text box presented earlier in this section.

3. The foundation assumptions of each of the Policy Paths. It is unclear how much Policy Path B or SREC-III would improve if they too only reimbursed VNM at the G rate.
4. The qualitative factors that need to be taken into consideration.

Nonetheless the modeling has brought into focus many implications of policies as presented throughout this report and next in the balance of Section 12.

12.2 Key Takeaways & Observations

Throughout the analysis, a list of key takeaways and observations have been identified that may guide interpretation of findings from this report.

12.2.1 SREC Policy

- **Future policies should not be judged on the sunk costs of past policies** – It is apparent from the cost and benefit analysis that SREC-I is much more costly than SREC-II or subsequent policies will and/or should be. Such cost should not be included in the determination of the impact of future polices as it would amplify the policy costs and distort the C:B metrics.
- **In-state spending and avoided capacity costs are important drivers to benefits of the Commonwealth at large** – This is apparent from the parametric sensitivity analysis, which shows that increasing the share of local installed cost and O&M expenditures would significantly increase the benefits to the Commonwealth at large. The same conclusion can be drawn for avoided capacity costs.
- **T&D charges avoided by onsite generation and VNM charges are significant in all scenarios and it is understandable that the utilities are concerned about the impacts of the current incentive framework.**
- **Virtual net metering is a very effective tool for supporting project and participant diversification** – Virtual net metering allows lower cost projects, such as community shared solar and low-income housing, which can leverage economies of scale to be built.
- **There is not a huge difference in costs to NPRs vs. revenue to CGs under the current SREC program, nonetheless ultimate costs to NPRs could decrease significantly with LSEs participation in the auction.**
- **In the uncapped scenarios, the DOER's price demand response auction mechanism is at risk of being overwhelmed with growth and leaving SREC prices near the SACP for more than 2 years in a row.**

12.2.2 Policy Paths A and B

- **Solar growth can occur at lower margins in a no-SREC future** – Current combination of SREC policy and net metering framework is providing large margins for a diverse array of project types and participants. From analysis of Policy Paths A and B, it is apparent that growth can still occur at lower margins.
- **Net metering and virtual net metering incentives are necessary to support more cost-effective project mix, but such incentives can be offered at a lower level** – As mentioned in several occasions above, net metering caps will change the project mix dramatically to more onsite and less cost effective project mix as it will drive smaller onsite projects. Under capped scenarios, community shared solar and low-income housing projects, which rely on virtual net metering will no longer be viable once the current net metering cap is reached. It should be noted it is both feasible and economical to retain the net metering mechanism in order to allow for virtually-net-metered projects, but at an incentive less than the current net metering credit rate (e.g. phasing down, or at retail generation only or at QF wholesale rates), as indicated by the results under Policy Path A (Uncapped).
- **Other objectives not quantified in the cost and benefit analysis may drive preference** – While Policy Paths A and B show improved B:C metrics compared to the SREC policy, several policy futures have similar enough B:C ratios for particular

perspectives that other objectives described in this report but are not quantified in the cost and benefit analysis, such as diversity of project types and beneficiaries, may drive preference.

Finally, it is important to note that the result of non-participating ratepayers costs exceeding benefits over the entire time horizon since 2010 is largely driven by inclusion of the legacy programs, SREC-I and to a lesser degree SREC-II. The subsequent programs – SREC-III, Policy Path A and Policy Path B, each are progressively more cost-effective than the legacy programs. While the scope of the analysis did not allow for rolling up costs in this manner, inspection of the results suggests that part or all of these policies may have a B:C ratio near or exceeding 1.0, which would indicate any subsidies being offset by tangible internalized benefits.

12.3 Limitations of this Analysis and Areas for Further Study

Throughout the analysis, a number of issues that may be of interest to stakeholders but which fell outside the prescribed scope were identified. Listed here are additional analyses and research areas which might merit further study. These issues fall under two categories:

- **Potential Sensitivity Analyses:** These potential sensitivity analyses could be accomplished, with additional effort, using the approach and models used in this study, but with differing inputs.
- **Potential Extensions of Analysis**: These potential extensions of the analysis would explore additional factors that were beyond the scope of this analysis

12.3.1 Potential Additional Sensitivity Analysis

Most input factors used in this analysis are projections subject to a degree of uncertainty. For some, the potential variation is modest and the degree of uncertainty is not potentially material to the analysis. Other exogenous factors may be subject to material uncertainty, and variations from the base assumptions used could yield different absolute and/or relative costs of benefits. The following introduces several variables identified throughout the analysis as sensitivities of potential interest.

12.3.1.1 Installed Cost Forecast

A single installed cost forecast was used in this analysis. Different costs would influence the Massachusetts solar supply curve and lead to different policy response and build-out, in absolute and possibly relative terms. In addition, since various components of Policy Paths A and B are derived from the installed cost forecast, changing the forecast would yield different policy impacts. It is expected that different installed cost futures would affect the build-out rate for DBIs thereby changing the policy timeline (i.e. when the 2,500 MW installed capacity target is reached). Different installed cost futures would also translate to different SREC prices and clearing prices for competitive solicitations under Policy Path A. A sensitivity varying the installed cost forecast could highlight the level of impact different solar cost futures have on each policy path.

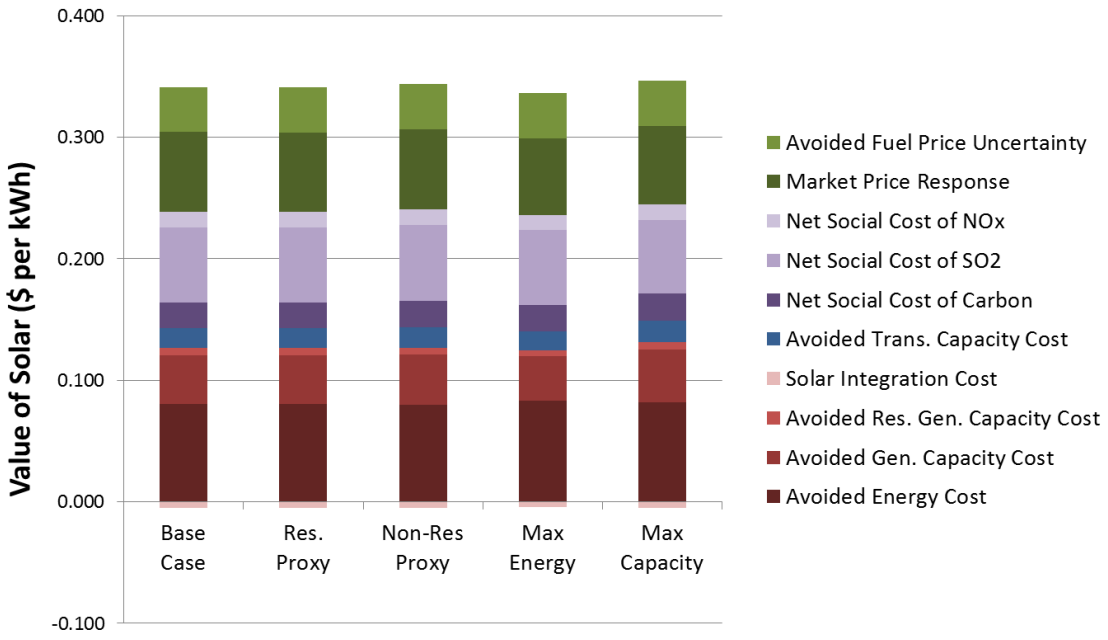
12.3.1.2 Financing Costs

Different financing cost assumptions were not included in this analysis as beyond the scope of this study. A sensitivity analysis using different financing cost assumptions could shed light on the impacts to the SREC policy and the alternative policy paths, such as required incentives, build-out rates, and project mix, under different market perspectives and expectations. One are of interest identified but not fully explored is the potential convergence of the costs of financing under SREC policies compared to long-term PBI incentives under Policy Paths A and B. As solar costs fall and the proportion of revenue dependent on SRECs relative to other revenue sources shrink, the impact of SREC price uncertainty on cost of capital would be expected to fall, potentially converging as cost premium shrinks.

12.3.1.3 System Orientation

Optimizing PV system orientation, such as the azimuth and tilt angle, could maximize the energy output and capacity of the representative PV fleets used in the analysis. Identifying maximum energy and maximum capacity fleets could maximize the benefits realized from solar PV, but the implication of different system orientations is uncertain without further research and study. As evidenced in the Maine Distributed Solar Valuation Study, maximum energy and maximum capacity fleets could have higher avoided energy costs than fleets representing more diverse blends of PV resources. The study also shows that the maximum capacity fleet could allow greater transmission peak load reductions compared to other fleets. However, maximum energy and maximum capacity fleets overall do not result in higher value of solar when all cost components, including social costs, are considered (see Figure 49). (Clean Power Research, LLC; Sustainable Energy Advantage, LLC; Perez Richard; Pace Law School Energy and Climate Center, 2015)

Figure 49: Maine Distributed Solar Valuation Study Fleet Production Profile Sensitivity (Central Maine Power)



12.3.1.4 Retail Rate Design

The results of this analysis presume no change to retail rate structures in Massachusetts, holding constant the proportion of total retail rates recovered through per kWh charges avoidable through on-site solar generation and net metered systems. In addition, no minimum bill was assumed. It was made clear by the Task Force that there is significant interest among some stakeholders in shifting some portion of distribution rates from kWh charges to kW charges or customer charges, or implementation of minimum bill. Task Force members agreed that this topic was best explored within a DPU-adjudicated venue. Analysis could be performed with changes in retail rate structure along these lines, revealing their impact on the results include program costs and benefits from the perspectives of the various stakeholders.

12.3.1.5 Exogenous Variables

The values of some cost and benefit components are dependent on future wholesale or retail rate trajectories, the value of capacity the FCM market, and the impact of current and future carbon regulation impact on energy market locational marginal prices, to name a few. Sensitivity analysis could be performed on these exogenous variables to explore their potential impact on the costs and benefits from the perspectives of the various stakeholders.

~~12.3.1.6 Alternative Role of Municipal Light Plants~~

This study assumed that Municipal Light Plants participate in the Policy Path A and B programs in the same manner as investor-owned EDCs. If MLP-located projects were ineligible, or MLPs did not offer analogous NM policies to those offered by EDCs, then the results would differ.

12.3.1.7 Consider the Impact of ITC Qualification Risk

This study ignored the potential impact on project developers of Federal ITC qualification peril at the ITC's incentive cliff on January 2017. In practice, projects that are exposed to completion and interconnection risk (risk of not interconnecting by this date) are likely to forego pursuit of their projects. While this study analyzed the expected installation and interconnection delays, it did not reflect developer and investor aversion to this risk, which is likely to cause them to leave an ample margin of error and forego pursuit of projects forecasted in this study to proceed that were at risk of missing the deadline due to potential variation in project timelines. A sensitivity analysis could explore this potential phenomenon, which would likely reveal a slower buildout than shown herein.

12.3.1.8 Variations in Detailed Design of Policy Paths A and B

This analysis revealed some design nuances within Policy Paths A and B which might in retrospect be defined differently to drive more optimal results. Additional analysis might consider altering some design features to examine the impacts on benefits and costs, possibly resulting in more optimal policy design. One example might be to allocate fewer MW to the Sector A large segments under Policy Paths A and B in the event that net metering is capped. Another might be relaxing the modeling constraints on Paths A to allow bids below levelized retail rate value.

12.3.2 Potential Extensions of Analysis

Several areas of interest for potential further study were identified throughout the analysis, including those discussed below.

12.3.2.1 Macroeconomic Analysis

All industry experience suggests that competitive procurements could alter market diversity, which in turn can impact the fraction of customer-generator revenue that is ultimately retained in state. The impact of different policy designs on the distribution of in-state versus out-of-state solar ownership and investment, hence cash flow within and outside of state, was only explored parametrically in this study but warrants further analysis. Further, an input-output model could shed light on the induced economic impacts (both positive and negative) and net job creation benefits among different policy options, which are not indicated in this analysis.

12.3.2.2 Refinement of Analysis Cost and Benefit Rollup

The scope of this study required tallying costs and benefits of the current and future policies across their durations, commencing in 2010 with SREC-I. The results make clear that successive solar policies following SREC-I are progressively more cost-effective, providing reduced level of incentive support and subsidy, and increasing relative benefits. The total costs and benefits incorporate the common, past and projected impacts of solar installed through committed 'legacy' programs (SREC-I and SREC-II up until the point at which future policy paths may diverge). If the analysis were to instead (or in addition) tally just the costs and benefits of future policies beyond the point of common legacy commitments, the differences in benefit:cost ratios from the various perspectives would likely be more stark, and it is possible that from the NPR perspective, the B:C ratios cold approach or surpass 1.0. The analysis framework unfortunately masks this potentially important result, but this information could be calculated with additional effort.

12.3.2.3 Targeted Solar Incentives to Desirable Solar Locations

Targeted incentives to support solar PV projects that support or benefit the Distribution system were not considered in this analysis. Analysis could be performed to examine the relative costs and benefits of either encouraging location of projects at desirable points on the EDC's distribution systems (potentially requiring substantial engineering analysis on the part of EDCs)

12.3.2.4 Consider Distribution System Saturation

In this analysis, distribution system saturation was not studies or assumed. However, in practice, certain areas of the EDC systems are likely to experience a degree of saturation leading to much higher interconnection costs. Additional analysis of distribution system saturation could be performed to more accurately reflect the likelihood of somewhat higher interconnection costs or diminishing numbers of locations where solar is economically attractive to build.

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