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The Commonwealth of Massachusetts

In the One Hundred and Eighty-Ninth General Court
(2015-2016)

Report of the Net Metering Task Force

(under the provisions of Section 7 of Chapter 251 of the Acts of 2014)

May, 2015

Massachusetts Net Metering and Solar Task Force

Final Report to the Legislature

April 30, 2015

Task Force Members

Dan Burgess, DOER Acting Commissioner; Task Force Co-Chair

Angie O'Connor, DPU Chair, Task Force Co-Chair

Benjamin B. Downing, Senator

Brian S. Dempsey, Representative

Eric J. Krathwohl, Rich May, P.C., appointed by Senate Minority Leader Bruce E. Tarr

Liam Holland, appointed by House Minority Leader Bradley H. Jones, Jr.

Paul Brennan, Attorney General's Office

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Robert Rio, Associated Industries of Massachusetts

Charles Harak, National Consumer Law Center

William Stillinger, Solar Energy Business Association of New England

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Janet Besser, New England Clean Energy Council

Geoff Chapin, Next Step Living

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Camilo Serna, Eversource Energy

Amy Rabinowitz, National Grid

Co-Chair Introduction

This comprehensive report outlines Task Force recommendations and Task Force Member opinions. It also includes extensive third-party research and analysis of solar incentives across the United States, alternative solar policy options for Massachusetts, a cost and benefit analysis of alternative policy options, and a full appendix that includes additional supporting documents. The Net Metering and Solar Task Force has met its statutory obligation with the completion of this report which reflects six months of meetings, research and analysis, discussion, public comment and negotiation.

The Baker-Polito Administration is committed to using the recommendations and analysis from the Net Metering and Solar Task Force as a foundation for working with the Massachusetts Legislature, energy community and other stakeholders to achieve continued solar growth and establish a framework for a sustainable solar program with reasonable ratepayer costs.

To that end, the Co-Chairs reaffirm earlier public remarks made by Energy and Environmental Affairs Secretary Matthew A. Beaton. In meeting the objectives of creating a program that not only reaches the 1,600 megawatt target – but also establishes a sustainable program beyond 2020 at reasonable cost – the program must reconcile two competing interests. Any future credit and incentive must be at the appropriate levels to continue driving the solar industry forward. At the same time, ratepayers who fund the programs through electric rates should not be paying more than is necessary to reach the installation goals.

With these priorities in mind, and the Baker-Polito Administration's emphasis on transparency, we note that the Task Force process included an analysis of the costs of the programs that support solar development. As discussed during this process, any cost projections are complex and involve numerous assumptions, and as a result, it is appropriate to consider benefits and costs. Nonetheless, based on analysis provided by the distribution company Task Force Members and by the Task Force consultant team, cost projections for non-participating ratepayers are in the range of $2.5 to $4 billion for the period 2014-2020.

In light of these projections, the Administration does not support raising the net metering caps in the short term absent a long term sustainable solution. Rather, we believe it is extremely important that any adjustments to the caps be accompanied by meaningful changes to the mix of incentives and proper consideration of the role of the ratepayers. As Secretary Beaton has articulated, the Commonwealth has a vital opportunity to develop a sustainable long term framework that effectively balances promoting clean energy and lowering costs to ratepayers. The Baker-Polito Administration looks forward to leading a dialogue to develop a program that strikes the right balance.

This Task Force has furthered the discussion of these crucial topics and we look forward to continuing this dialogue over the coming months. Thank you to the Task Force Members, consultants, staff, and stakeholders who have spent countless hours working together on this report.

Sincerely,

Dan Burgess
Acting Commissioner
Department of Energy Resources

Angela M. O'Connor

Angie O'Connor
Chairman
Department of Public Utilities

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Executive Summary

Summary of Task Force Process

On August 6, 2014, An Act Relative to Credit for Thermal Energy Generated with Renewable Fuels, Chapter 251 of the Acts of 2014 ("Act") established a net metering task force ("Task Force"). The Act directs the Task Force to "review the long-term viability of net metering and develop recommendations on incentives and programs to support the deployment of 1,600 megawatts ("MW") of solar generation facilities in the Commonwealth."

The Task Force consists of 17 members as directed by the Act and was co-chaired by the Department of Energy Resources ("DOER") and the Department of Public Utilities ("DPU"). The Task Force convened for the first time on November 13, 2014. Since that date, the Task Force has held twelve meetings. At its initial meeting, the Task Force reviewed and approved a set of Task Force Ground Rules and a Task Force Framing Document. As directed by the Act, two of the Task Force meetings were devoted primarily to public comment; the first was held on January 6, 2015 in Boston, and the second was held on February 25, 2015 in Holyoke. The majority of the other Task Force meetings also provided the opportunity for public comment. Members of the public were invited to submit comments at any time to the Task Force via a Task Force e-mail address. A Net Metering and Solar Task Force website[1] was also established as a resource for Task Force Members and members of the public and contains copies of all Task Force-related documents, including the final Net Metering and Solar Task Force Report.[2]

Recognizing the need for an in-depth review and analysis of various solar incentives and net metering policy options, DOER hired a team of consultants to work with the Task Force.[3] The work of this consultant team was intended to inform Task Force deliberations but not replace the statutory duties of the Task Force. The Task Force Members reviewed and approved a Consultant Scope of Work involving six separate tasks to be completed by the consultants:

- Task 0: Interviews of Task Force Members and Other Stakeholders
- Task 1: Summary of Solar Incentive Programs Offered in Other States
- Task 2: Summary of Solar Development in Other States without Solar Incentive Policies
- Task 3: Analysis of the Costs and Benefits of Massachusetts ("MA") Net Metering and Solar Incentive Policies
- Task 4: Provide a Range of Options to Reach the 1,600 MW Goal
- Task 5: Minimum Bill Survey and Analysis

1 See http://www.mass.gov/eea/energy-utilities-clean-tech/nms-taskforce/.

2 Available documents include upcoming Task Force meeting schedules and agendas, a list of Task Force Members, Consultant Task Reports, consultant presentations, public comments, the Task Force Framing Memorandum, Task Force Ground Rules, and Task Force Scope of Work, past meeting agendas, meeting minutes, and other miscellaneous Task Force-related documents.

3 The consulting team consisted of Peregrine Energy Group, Sustainable Energy Advantage, LLC, Meister Consultants Group, and La Capra Associates.

Each of the consultant tasks has involved ongoing input from the Task Force Members. During Task Force meetings, the consultants presented their findings for all tasks. The presentations were interactive in nature and involved Task Force Member input, questions, and discussion. Task Force Members were encouraged to submit comments and edits to the consultant presentations and summaries, but ultimately, the consultants had final say over whether or not to include these suggestions. The Consultant Task Reports sought to inform Task Force discussion, including the development of the "Task Force Recommendations," however, the short timeframe of both the Task Force and consultant's work limited the ability of Members to fully analyze, query or incorporate certain data into the recommendations. Inclusion of the Consultant Task Reports in the Net Metering and Solar Task Force Report does not constitute the endorsement of the consultant's recommendations and analysis by the Task Force Members.

As the last step in the process of compiling the report to the Legislature, Task Force Members drafted final recommendations in small sub-groups to present to the larger Task Force, which were discussed and refined over the course of the final six meetings. The final recommendations represent a consensus of the Task Force where possible. Where disagreement remained, the final recommendations include a discussion of the various points of view on the topic. Task Force Members were also encouraged to provide individual statements as a supplement to the group's final recommendations, which are provided herein. The "Task Force Recommendations" contained herein represent the only views endorsed by the Task Force and are offered as such following unanimous approval by Task Force Members.[4] This report contains consultant task reports for use as background information, rather than a representation of the recommendations or beliefs of the Task Force.

Key Findings and Recommendations

Following several months of discussion among Task Force Members, a substantive discussion around recommendations was begun at the March 26, 2015 meeting, with the introduction of an initial recommendations framework document drafted by the DOER and the DPU staff. This document was designed to stimulate discussion, identify areas of agreement and disagreement, and help Task Force Members develop consensus on the issues faced. Using the document and discussions from the March 26, 2015, and April 6, 2015 meetings as a template, Task Force Members broke into subgroups to discuss specific issues and draft recommendation statements. These recommendation statements were then used to compile the recommendations section of this report, which immediately follows this section. The recommendations are divided up into the following sections:

1. General Principles
2. Solar Cost/Benefit Study
3. Solar Incentive Program Design
4. Net Metering and Net Metering Caps
5. Geographic Distribution
6. Fair Compensation for Use of the Distribution Grid
7. Treatment of Municipal Light Plants

[4] Christina Fisher, designee of Senator Benjamin Downing, abstained from voting. Neither Representative Brian Dempsey, nor his designee, were present for voting.

8. Further Recommendations

Each section identifies consensus recommendations made by the Task Force Members on specific issues. Where consensus could not be reached, differing positions are summarized by the Members supporting each position.

Task Force Member Individual Statements are included to supplement the group's final recommendations. In the Individual Statements, Task Force Members provide their individual opinions and positions on the final Net Metering and Solar Task Force Report delivered to the Legislature.

Summary of Consultant Task Reports

In their proposal, the consultants agreed to perform six separate tasks, which generally aligned with the Scope of Work approved by the Task Force Members and Request for Quote solicited by DOER. In performing each of these tasks, the consultants prepared individual reports, each of which are provided in the body of the report. The Task Reports included in this report represent the work of the Consultant and while they were intended to inform Task Force discussions, they were not necessarily endorsed or incorporated by Task Force Members in the "Task Force Recommendations." In particular, the final Task 3 Report came very late in the process, leaving the Task Force Members with little ability to clarify the results or question the modeling analysis.

Task 0: Interviews of Task Force Members and Other Stakeholders

In order to better understand the perspectives of Task Force Members and other stakeholders, the consulting team organized five 1.5 hours phone-based focus group sessions. Focus groups sessions included Task Force Members representing similar constituencies. These sessions were conducted for the following Task Force groupings:

- Utilities;
- Utility customers and customer advocates;
- Solar industry representatives;
- Legislators; and
- Non-Task Force stakeholders.

Themes explored during these focus groups included: perspectives on the current solar market model, perspectives on the current net metering approach, long-term goals for the Massachusetts solar market, perspectives on other solar incentive models, and perspectives on the future use of net metering and minimum bill provisions. Participants were provided with the opportunity to provide written comments along with their focus group session comments. Transcripts of these discussions are provided as an addendum to this report in Appendix A.

Task 1: Summary of Solar Incentive Programs Offered in Other States

In order to better understand the range of options available to the Task Force in making its recommendations, the consulting team conducted literature reviews to develop policy summaries that discuss the critical elements of a range of incentive mechanisms, from declining block programs to long-term contract solicitations and utility ownership programs. Policies reviewed under this task include:

- The California Renewable Market Adjusting Tariff (“Re-MAT”), Renewable Auction Mechanism (“RAM”) and declining block programs;
- The New York declining block programs;
- The Rhode Island Renewable Energy Growth program;
- The Delaware Solar Renewable Energy Credit (“SREC”) Solicitation program;
- The Connecticut Zero Emissions Renewable Energy Credit (“ZREC”) program;
- Utility financing, ownership, and long-term contracting programs in New Jersey;
- The Vermont Sustainably Priced Energy for Economic Development (“SPEED”) long-term contracting program; and
- Value of Solar Tariffs.

The policy choices made to develop each of these unique programs represent efforts by policymakers to balance sometimes-conflicting goals of solar market development scale and speed with ratepayer cost impacts. The summaries developed by the consulting team examine critical policy elements, such as program structure, incentive-setting mechanisms, market size, long-term market goals, complimentary incentives and programs, resulting market characteristics, and other key elements.

Task 2: Summary of Solar Development in Other States without Solar Incentive Policies

In the Task Force’s initial meeting, the Members expressed an interest in understanding the relationship between state solar programs and actual deployment of solar, and whether it might be reasonable to expect solar development even in the absence of significant state programs. The purpose of Task 2 was to provide a representative analysis of the level of solar development in states that do not have a state-level incentive program.

The consulting team’s analysis was divided into three components: 1) a review of solar market development in states that do not have net metering; 2) a review of solar market development in states that have similar characteristics to Massachusetts in terms of the economic value of solar production; and 3) a review of recently announced large-scale solar installations in states and utility territories that do not have substantial solar incentives.

The analysis shows that solar market development has been largely dependent on state-level policies in the United States. States that do not offer net metering have had highly limited solar market development compared to Massachusetts. Additionally, state-level targets and incentives have been a major driver of solar market development to date. The analysis also shows that states without robust solar incentives and targets, but adequate solar potential, have seen very limited market growth compared to similar states with solar incentives and binding targets. This suggests that, for the time being, state-level solar policies are critical to future solar market growth in the U.S.

Task 3: Analysis of the Costs and Benefits of MA Net Metering and Solar Incentive Policies

The consultant work on Task 3 set out to calculate the cost and benefits of the current policy and potential future net metering and solar incentive policy options identified in Task 4. However, with the variety of perspectives required for examination by the statute and from the Task Force stakeholders, the analysis represents one approach to a solar cost-benefit analysis, and is not a "Value of Solar" study.

Task Force Members gave input on the policy paths to model (leaning on Task 4 information) and on the assumptions for the modeling. However, the final modeling inputs, analysis, and results represent the independent work of the consultants. Additionally, Task Force Members had little time to digest, understand and analyze the Task 3 report and therefore were largely unable to incorporate these results in the recommendations and individual statements contained herein.

In order to determine the costs and benefits associated with alternatives to Massachusetts' current solar policies, the Task 3 report 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, with existing (and, for SREC-III, forecasted) Solar Alternative Compliance Payment ("SACP") and Solar Credit Clearinghouse Auction ("SCCA") trajectories serving 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 kilowatts, "kW"), and through competitive bidding for the large projects (> 25 kW). 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 solar photovoltaic ("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 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 2,500 MW (or remains at 1,600 MW);
- Whether the aggregate net metering caps under current law remain in place or are removed.

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 directly 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

- Under all scenarios, Massachusetts reaches its current goal of 1,600 MW of solar by 2019.
- All future scenarios examined would be less expensive than the current SREC-I and SREC-II program.
- The choice of policy path affects the costs and benefits, the type of systems that will be built, and the category of participant impacted.

Task 4: Provide a Range of Options to Reach the 1,600 MW Goal

In order to conduct the modeling in Task 3, the Task Force Members first had to select the potential futures, or "policy paths", to be modeled. Utilizing the research conducted in Tasks 1 and 2, stakeholder objectives as expressed in the focus groups conducted in Task 0, and public comment, the consulting team developed an initial set of seven potential policy paths. These paths were discussed at the Task Force meeting on February 12, 2015. After the meeting, additional Task Force feedback on the paths was solicited through a survey, and a narrowed set of three options was presented to the Task Force on March 5, 2015. At that meeting, the Task Force modified the options and selected the set to be modeled.

In selecting these policy paths, the Task Force Members made an explicit distinction between selecting paths for modeling and selecting paths for potential implementation. For the modeling exercise, the Task Force's objective was to choose paths for which the modeling would generate useful information. The selection of a path for modeling is not an indication that a majority, or indeed any, of the Task Force members would like to see that path implemented.

Task 5: Minimum Bill Survey and Analysis

Minimum bill mechanisms have been designed to ensure a minimum customer contribution toward the costs of the distribution system from all ratepayers and to reduce the potential impacts of customer cross-subsidization. Minimum bills differ from other bill mechanisms such as customer charges and demand charges in that they are designed to only impact a limited segment of utility customers, leaving rates and charges for customers who regularly exceed the minimum bill unaltered. The Task 5 report reviews the theory behind the minimum bill mechanism, evaluates the impact of minimum bills in other states, and models the potential impact of a minimum bill on a representative PV system in Massachusetts. Key findings include:

- Residential minimum bills that have been implemented in other states have, to date, been relatively modest, ranging from $1.77 per month in one California jurisdiction to $25 per month for large customers of one Hawaii utility.
- Minimum bills have been implemented in some of the most robust solar markets in the country, suggesting that these mechanisms, at the rates implemented, are not incompatible with PV market growth.

- Cash flow modeling of a Massachusetts residential PV system shows that the impact of a minimum bill policy will vary significantly based on the size of the PV system relative to the annual electric load of a home and the minimum bill level.
- Modeling also indicates that minimum bills could have a greater impact on lower consumption utility customers compared to customers with average consumption assuming both are subject to the same minimum bill.

Summary of Appendices

Additional documents and information produced over the course of six months of meetings, research and analysis, discussion, public comment and negotiation by the Net Metering and Solar Task Force are included in the Appendices. The Appendices are divided into the following sections:

Appendix A: Task Report 0 Summary of Interviews and Written Responses: The complete set of interview summaries and written responses received as part of Task 0.

Appendix B: Task Report 3 Appendices: Detailed information on the key assumptions, results, and modeling parameters used by the consultant for the purposes of analyzing the costs and benefits of Massachusetts net metering and solar incentive policies.

Appendix C: Consultant PowerPoint Presentations: Task 4 power point presentation.

Appendix D: Utility Data Request and Responses: The complete set of responses received in response to the information request made to the utilities on the projection of the total cost for solar generation support programs.

Appendix E: Other Documents: Link to additional documents related to the efforts of the Task Force, including: Public Comments; Task Force Ground Rules; Task Force Framing Document; Task Force Scope; Meeting Agendas; and, Meeting Minutes

Task Force Recommendations

The Task Force Members submit the following recommendations for the Legislature's consideration[5]:

General Principles

The Task Force Members support a policy to maintain the growth of the solar market to 1,600 megawatts (MW) and beyond.

The long-term goal of any policy should be for the renewable energy industry, including solar developers, to be competitive with other sources of energy, taking into account the characteristics of each resource. Policy design should promote the orderly transition to a diverse and self-sustaining solar industry. This will induce investment in Massachusetts, generate new local jobs and sustain existing ones, and contribute to the reduction of greenhouse gas emissions. The Task Force Members also recognize as valuable the maintenance of solar market diversity in Massachusetts in terms of the scale of solar projects, the locations of solar projects, and the range of firm sizes, both local and national, and ensuring ease of market entry, as well as enabling equitable access to solar, where reasonable.

The Task Force Members recognize that there are costs, as well as benefits, for ratepayers associated with net metering and incentive policies. In particular, attention should be paid to the balance of costs and benefits for those who do not own or receive direct economic benefit from solar or other qualifying distributed generation. The issue of cost impacts on participants and non-participants is not a new issue in electricity policy. Accordingly, here as elsewhere, consideration of any policy should include a careful examination of costs and benefits to ensure that the policy is as cost-effective as possible and that ratepayer costs are minimized.

The Task Force Members recognize that the development of solar generation and the industry require an increased understanding of the costs and value of developing and integrating solar on the distribution system, and recommend that work continue to assess this.

Everyone who is connected to the distribution system should contribute their fair share towards their use of it and towards the system benefits included on the distribution company bill for public policy reasons (e.g., low income support and energy efficiency).

The Task Force Members support solar policies that ensure incentives are tied to market signals, are transparent, reduce any subsidies, and achieve solar deployment goals and policy objectives while minimizing ratepayer contributions.

The Task Force Members support implementing a new policy framework as soon as possible, but also recognize the timelines associated with legislative and regulatory processes. The Task Force Members also recognize the potential upcoming changes to federal incentives such as the Investment Tax Credit ("ITC"), and urge legislative action in a timeframe to allow regulatory implementation to occur prior to January 1, 2017, which is the scheduled expiration date of the ITC.

[5] DOER and DPU abstained from any recommendations pertaining to Executive Branch action.

With this understanding, the Task Force Members recommend that any new policy be fully implemented with due notice to the solar industry. To enable smooth, low-cost transition to a new policy structure, visibility about the details of the new structure should be provided several (6-8) months in advance of the policy implementation date.

The establishment of any future solar goal should either be determined by the Legislature or established via a stakeholder/regulatory process led by the Department of Energy Resources ("DOER") and the Department of Public Utilities ("DPU").

While there is disagreement on whether existing net metering facilities should be grandfathered under a new policy framework, Task Force Members agree that existing projects and projects with Statements/Assurances of Qualification that were obtained prior to any new policy framework being adopted shall continue to receive Solar Renewable Energy Certificates ("SRECs") under the current SREC policy frameworks.

Value of Solar/Comprehensive Benefit Cost Study

(Note: DOER and DPU abstained from these recommendations).

Task Force Members support conducting a comprehensive and transparent solar benefit/cost study to determine the value and impact of solar in Massachusetts.

Value of Solar studies evaluate total benefits in two broad categories: a) system benefits, including avoided system costs and b) societal benefits. These studies do not evaluate utility-specific system needs.

An understanding of costs to build and generate solar as well as an understanding of benefits from solar should be very clearly separated in the study.

A Value of Solar study can inform compensation and incentives for solar, but is not determinative.

If undertaken, this study should be spearheaded by DOER and DPU, with a scope to be informed by input from interested stakeholders. The study should be undertaken on a schedule such that it would not delay implementation of a new policy framework.

Solar Incentive Program Design

The Task Force Members support a solar incentive policy framework that supports diversity in the type and geographic locations of solar installations. Forms of support such as grants, rebates, tax credits, and incentives should be considered for specific locations or system types, and would increase the transparency of the costs and benefits of these particular system types. Incentive levels and sources should be differentiated in order to support diverse installation types that provide unique benefits.

In particular, incentive levels should be differentiated in a way that recognizes the differences between small, medium, and large scale solar projects. The Task Force recommends that the size thresholds that determine these categories should either be set by the Legislature or established via a stakeholder/regulatory process led by DOER/DPU.

Additional compensation that is necessary to achieve policy goals, such as landfill, brownfield, low income, community shared solar, and parking canopy development, can be provided by targeted incremental incentive value, separate from the net metering credit.

Consideration should be given to leveraging outside funding sources to provide upfront incentives to solar projects when benefits achieved are outside of the electrical system (i.e., economic development, landfill development, etc.). An example of such outside funding sources would be a refundable tax credit for state residents.

Any new incentive framework for solar should have the following attributes:

a. Promote the orderly transition to a stable, equitable and self-sustaining solar market, in which solar incentive levels are equivalent to those offered in broader renewable programs available in the Commonwealth.
b. Track underlying system costs and revenue streams (i.e., module costs, balance of system costs, installation costs, soft costs, and revenues available from other sources).
c. Rely on market-based mechanisms and/or price signals as much as possible to set incentive levels.
d. Minimize direct and indirect (i.e., administrative and transaction-related) program costs and barriers.
e. Feature a known or easily estimated budget to achieve program goals.
f. Differentiate incentive levels to support diverse installation types that provide unique benefits.
g. Promote investor confidence through long-term incentive revenue certainty and market stability.
h. Be readily adaptable to changing market conditions.

Recommendations Specific to Small Scale Solar Projects

Any incentive policy for small scale solar should be performance-based and should particularly provide open access for small scale distributed solar projects and such projects should not have to participate in competitive solicitations.

The Task Force Members support a continuation of the SREC II incentive program for small solar projects until a new solar policy can become effective. At that time, a replacement such as a carefully designed Declining Block Incentive tariff with adjustments to increase/decrease value based on market growth would be an acceptable form of incentives for small solar.

Recommendations Specific to Large Scale Solar Projects

Large scale distributed solar can bring scale economies to reaching the Commonwealth's overall solar goals at lower cost and therefore should be part of a diverse state-based solar market.

Incentives delivered to owners and developers of large scale distributed solar systems should be limited to an amount necessary to support the economic viability of efficiently developed and financed systems.

In addition to the attributes applicable to any new incentive framework, generally, which are listed above, incentives for large scale distributed solar should have the following attributes:

a. Impose competitive discipline on market participants and create a robust competitive marketplace.
b. Have performance-based incentives (i.e., paid out over time based on demonstrated actual production).
c. Be designed to avoid conflicts with Federal Energy Regulatory Commission jurisdiction over markets for energy and capacity.
d. Support both orderly deal flow and the orderly recovery of the system costs from its beneficiaries (i.e., a regularly available incentive structure to prevent start/stop markets, and regular contributions to the expenses associated with the electric distribution grid).

Incentive Delivery Mechanism for Large Scale Distributed Solar

Position # 1 (Supported by Eric Krathwohl, David Colton, William Stillinger, Fred Zalcman, Janet Besser, Larry Aller (alternate for Geoff Chapin), Lisa Podgurski)

Task Force Members recommend a Declining Block Incentive that can adjust to respond to market conditions. In the view of these parties, it is critical for the Task Force's objectives that the incentive be designed as an "open access" program where incentives are continuously available to market participants. In the view of these Task Force Members, a Declining Block Incentive has the following key advantages:

a. The incentive level is transparent and predictable. While a competitive procurement model also offers the key advantage of providing clarity on future revenues, the declining block model has the advantage of providing transparency on incentive level and availability during early-stage project development.
b. The program is "always on." Incentive funding is available to projects on their development schedule, not on the solicitation schedule.
c. The program budget is fixed. A declining block model locks in the total ratepayer expenditure for the incentive program. It is simply the sum of all capacity blocks multiplied by the associated incentive level.
d. It imposes market discipline and leads to a self-sustaining industry. The program encourages cost-cutting and competition. Low-cost providers gain the greatest market share. And the end-state of the program is a mature market that can sustain itself without incentives.

Position # 2 (Supported by Paul Brennan, Liam Holland, Robert Rio, Charles Harak, Camilo Serna, Amy Rabinowitz)

Task Force Members recommend a Competitive Procurement Model. In the view of these Task Force Members, Competitive Solicitations are one of the most widely used methods for procurement of energy and related products within the utility and power industry. In the view of these Task Force Members, they are repeatedly chosen as the preferred method of procurement due to a number of clear advantages:

a. Open and competitive solicitations result in highly transparent pricing based entirely on the response from the active market.
b. Competition provides assurance that customers pay only what is necessary to support cost-efficient suppliers.
c. The total cost, volume of purchases, and market activity can be readily managed within a solicitation framework.
d. Typical solicitation terms encourage market discipline by requiring suppliers to submit binding proposals and including non-performance penalties.

Net Metering and Net Metering Caps

The Task Force Members note that the discussion around net metering and net metering caps is focused on how solar fits into the net metering construct. The Task Force Members recognize that other renewable energy and clean energy sources are eligible for net metering, but are not making any specific recommendations to the Legislature to change how these sources should be treated with respect to net metering.

Net Metering Compensation

Position # 1 (Supported by Eric Krathwohl, Paul Brennan, Liam Holland, David Colton, Charles Harak, William Stillinger, Fred Zalcman, Janet Besser, Larry Aller (alternate for Geoff Chapin), Lisa Podgurski)

Some Task Force Members propose the following:

Solar generators should receive fair compensation for the value that solar provides to the grid and to the Commonwealth overall through a combination of bill credit value and additional compensation from incentives or other sources.

Fair value should be determined through a comprehensive solar benefit/cost study. This study should quantify the various value streams associated with solar generation. The study should analyze the value of different "categories" of projects:

a. Behind the meter projects
    i. Projects designed to serve no more than 100% of annual load allowing for some reasonable amount of growth such as heat pumps and electric vehicle charging, as well as projects designed to predominately serve behind-the-meter load but may incidentally export.
b. Proximate to load projects
    i. The solar facility is located on and serves a distinct campus of buildings under common ownership. This would include, but not be limited to, municipal facilities, colleges and universities, hospitals, industrial plants, office parks, and retail developments.
    ii. The solar facility is located within and serves a group of market rate and/or low income residential units joined by an association. This would include, but not be limited to, residential condominium associations, apartment buildings/complexes under common management, and homeowners associations.

iii. The solar facility is located within and serves a distinct and contiguous municipal zoning district. This would include, but not be limited to, central business districts, residential subdivisions, urban neighborhoods, community shared solar, and agricultural zones.

c. Projects within the same load zone but not "proximate to load"
   i. This will cover many types of projects that qualify as virtual net metering today.

If a comprehensive solar benefit/cost study reveals significant cross-subsidization, either from or to solar generators, the DPU should be authorized to open a proceeding to investigate the need and how to address it.

Assuming a credit value that returns to the solar generator only the fair value of benefits provided, and correspondingly, utilities receive fair compensation for the services provided to solar generators, caps on net metering should be removed.

Projects in operation or those with Net Metering Cap Allocations that were obtained prior to any new policy framework being adopted shall receive compensation/credit under the current policy framework.

<u>Position # 2</u> (Supported by Robert Rio, Camilo Serna, Amy Rabinowitz)

Task Force Members believe that the cost of net metering to ratepayers needs to be addressed as soon as possible. These Task Force Members recommend a model by which solar generation output is valued at retail generation or Qualifying Facility wholesale rates, because solar production displaces another electricity source. Payments to solar hosts should be based on production that is separately measured by the distribution company. Payments to solar hosts should not include distribution and transmission.

Instead, to the extent that energy and other generation attributes of solar facilities provide benefits to the distribution grid that are known, measureable, and verifiable and that actually reduce utility cost of service to customers, they will be compensated. Compensation for societal or environmental benefits, such as those included in the Renewable Portfolio Standard ("RPS"), should be provided as discussed in the Small and Large Solar Incentive sections.

Task Force Members also recommend that the ability to transfer excess net metering credits be replaced by payments for energy and other generation attributes, as described above, that would be made to the solar host who, in turn, would be free to enjoy or distribute such compensation as it saw fit.

In order for solar to be compensated for any service to the electric distribution grid, the amount paid should be less costly than alternatives, including, for example, distribution investment, energy efficiency, and demand response.

In order to get fair compensation for the distribution system, all net metering customers should be moved to the new compensation as soon as is practical. The specifics on timing of such move can be determined through a DPU proceeding.

<u>Net Metering Caps</u>

Near-term adjustments to existing net metering caps

At the time of this writing, the existing net metering caps have been reached in National Grid's service territory. Some smaller systems are exempt from net metering caps. Updated information on net metering caps can be found at www.massaca.org.

Position # 1 (Supported by Paul Brennan, Eric Krathwohl, David Colton, Charles Harak, William Stillinger, Fred Zalcman, Janet Besser, Larry Aller (alternate for Geoff Chapin), Lisa Podgurski)

The Legislature should raise the net metering caps a limited amount so as to avoid adverse consequences that would otherwise occur to solar development during the pendency of the legislative review and administrative implementation of long-term sustainable solar policies.

Position # 2 (Supported by Robert Rio, Camilo Serna, Amy Rabinowitz)

Task Force Members believe that raising the net metering caps will cause adverse consequences to non-participating ratepayers and is not necessary to continue the growth of solar and therefore should not be adjusted until the overall policy structure is updated and implemented.

Net Metering Caps Over the Long-Term

Position # 1 (Supported by Paul Brennan, Eric Krathwohl, Liam Holland, David Colton, Charles Harak, William Stillinger, Fred Zalcman, Janet Besser, Larry Aller (alternate for Geoff Chapin), Lisa Podgurski)

Caps on net metering can be eliminated over the long-term if certain other actions and measures are taken. Specifically, the Task Force Members believe that caps on net metering are no longer necessary where: 1) All customers, including solar generators, are paying their fair share for grid services; and 2) All customers are receiving the fair value for the services and products they supply to the grid and Commonwealth at large.

To make this determination, a comprehensive and transparent study to identify the benefits and costs of solar to ratepayers, the distribution system, and the Commonwealth as a whole should be completed. Should either a significant net cost or benefit to ratepayers be found, appropriate rate design or financial mechanisms should be implemented.

Position # 2 (Supported by Paul Brennan, Eric Krathwohl, Liam Holland, Robert Rio, Camilo Serna, Amy Rabinowitz)

The ability to increase or remove net metering caps is dependent upon the level of progress towards fair and full compensation by users of the grid for that use and social benefit costs, and non-participant ratepayers costs that are reasonable and justified.

Geographic Distribution

The Task Force Members agree that there should be an equal opportunity for solar development across the state.

Total solar compensation (inclusive of any incentives and net metering credits) that is the same amount across the state will encourage a more even geographic distribution of solar generation across the state.

Encouraging solar generation where it can provide benefits to the distribution system should be explored and evaluated in relation to other public policy objectives. Studies could be performed to investigate and capture empirical data about the value of solar to a company's electric system and customers to provide information about the value of solar generation to electric system operations, investment deferral and other potential values. This information should be made available to solar developers subject to appropriate safeguards.

Fair Compensation for Use of the Distribution Grid[6]

The Task Force Members agree that everyone who is connected to the distribution system should contribute towards their use of it and towards the system benefits charges included on the distribution company bill for public policy reasons (e.g. low income support and energy efficiency).

A fair compensation mechanism should apply to all customers, should be cost based, and should be set in accordance with the customer's use of the distribution system.

The level of any charges associated with a fair compensation mechanism for a group of customers or rate class should take into account customer size and/or other service characteristics in order to develop appropriately sized contributions.

A fair compensation mechanism should be designed appropriately for low income customers consistent with the DPU's established rate design principles.

Specifics of rate design and rate levels should be determined by the DPU in a utility-specific evidentiary proceeding consistent with the DPU's established rate design principles of efficiency, simplicity, continuity, fairness, and earnings stability. These factors, along with transparency and understandability, are important when considering a fair compensation mechanism and in determining rates for all components of service for all customers.

At the discretion of the distribution company and approval by the DPU, a fair compensation mechanism should be considered through a distribution company's base rate case, a revenue neutral rate design proceeding, or the grid modernization filing.

Following any initial setting and implementation, the DPU should and will review the fair compensation mechanism during distribution company rate cases.

Treatment of Municipal Light Plants ("MLPs")

(Eric Krathwohl, David Colton, and Charles Harak abstained from making recommendations on this issue)

The value of SRECs come from the requirement under M.G.L. c. 25A § 11F that retail electricity suppliers purchase SRECs and pass the costs to their customers. This section exempts MLPs and their customers from this requirement while not prohibiting solar facilities owned by MLPs or their customers from

[6] This addresses the Task Force's charge from the Legislature to address a monthly minimum bill.

generating and selling SRECs. This exemption results in Investor Owned Utility ("IOU") customers paying for the SRECs generated by projects located in MLPs.

Given the historical exclusion for MLPs from requirements and regulations imposed upon IOUs, the Task Force Members do not recommend any mandates on MLPs at this time. However, the members do suggest that the Legislature explore the following issues with respect to MLPs:

a. RPS cross-subsidization (i.e., who pays for future SRECs)
b. MLP customer access to solar (e.g., explore opt-in by MLPs to solar policy structure)
c. Clarify that MLPs may allow third-party owned on-site distributed generation transactions without undermining their retail franchise.

Further Recommendations

Although not central to the scope of this Task Force, the Task Force recognizes that there could be opportunities to reduce soft costs associated with project permitting, interconnection timing and process, taxes, and financial risk of project incentive revenue streams that could be addressed.

Permitting

In particular, a process to support a uniform and expedited permitting process for small solar installations across the Commonwealth should be explored. While a single state-wide process may not be possible, state legislation can provide significant value by enabling a standardized and expedited process based on best practices to be shared and put in place by Massachusetts municipalities. Examples of states that have successfully implemented such approaches are Vermont, California, and New York, in which efforts have been particularly focused on small systems, generally 25 kilowatts or below.

Interconnection

Task Force Members recommend that the Technical Standards Review Group , DPU, and DOER continue to ensure that the most efficient interconnection practices possible are being utilized, noting that interconnection processes are complex, yet important as they address safety and reliability issues regarding the electric distribution grid.

Taxes

The Task Force Members note that there has been considerable confusion and/or variable treatment at the municipal level of the appropriate approach to taxing of solar facilities, and accordingly recommend that the Legislature should direct the Department of Revenue to provide clear guidance regarding municipal taxation that will have the salutary effect of assisting municipalities and providing greater consistency and certainty for solar developers and owners.

Additionally, the Task Force Members suggest the possibility of authorizing municipalities to grant local tax credits for solar facilities if that is desired by the municipality.

The Task Force Members observe that solar development could be supported via refinements of off-bill revenue.

Task Force Member Individual Statements

Note: The following section contains statements from individual Task Force Members. These statements reflect their individual viewpoints and were not reviewed or approved by the Task Force.

Associated Industries of Massachusetts, Robert Rio

Associated Industries of Massachusetts (AIM) is the state's largest nonprofit, nonpartisan association of Massachusetts employers. AIM's mission is to promote the well-being of its thousands of members and their employees and the prosperity of the Commonwealth of Massachusetts by improving the economic climate, proactively advocating fair and equitable public policy, and providing relevant, reliable information and excellent services.

As a member of the Net Metering Task Force, we are pleased to offer the following comments for inclusion into the Task Force Report to the Legislature.

The High Cost of Electricity is Hurting Business in the Commonwealth

According to the Energy Information Administration ((EIA) – part of the federal Department of Energy), Massachusetts has the highest or near the highest cost of electricity in the United States, double that of states which compete with us for business.

The impact of this high cost on business competitiveness and the difficulty Massachusetts has attracting and retaining important business is not anecdotal. EMC, a company with deep roots in Massachusetts, recently constructed a data center in North Carolina explaining that the action was precipitated *"Because of the high energy costs in Massachusetts".*

And it is not just large companies concerned about energy costs. In a recent outreach to AIM members, we heard from several businesses concerning the negative impacts these high costs have on their operations. Among the more poignant comments are two from small businesses: *"We have seen a 55% increase in our power costs over the last 2 years. It is hurting our company significantly"* and "*Utilities and insurance are without a doubt our largest financial drains".*

Reducing the Cost of Solar Programs and Electricity Should be the Highest Priority

In recent years, AIM heard several justifications for solar and other "green" programs: they will create jobs or keep money in Massachusetts; lower carbon emissions or allow diversity of our energy mix, andeven lower ratepayer costs. Under scrutiny, however, virtually none of these goals were realized – in fact, they may be at odds with each other. With virtually no coal or oil being used regularly in

Massachusetts, our electric generation supply is much cleaner than ever and much cleaner than virtually all other parts of the United States.

There should be only one goal for any energy program - to reduce the cost of energy in Massachusetts.

With this backdrop the goal for supporting solar and other renewables should also be clear. Renewable energy, including solar procured through the programs that are the subject of this task force, should have demonstrable benefits and be procured at the lowest cost, using a competitive market without preference as to technology. This is not the case now. In data submitted to the Task Force, Eversource (formerly Northeast Utilities) showed that because of our generous subsidies through the SREC and net metering programs, procuring solar power in Massachusetts is more than double the cost of procuring the same power in neighboring states! Lower costs, even with renewable power, is achievable.

Current solar program costs (which include SRECs and net metering) are unsustainable. While lack of natural gas pipeline capacity is a major driver of recent energy increases, solar costs are growing. Unchecked, National Grid and Eversource estimate that the ratepayer impact of the current solar program through 2020 will be over 4 billion dollars; adding 10-15% to the distribution portion of the electric bill. Worse, as steps are taken to reduce the price of natural gas by increasing capacity (See D.P.U. 15-37) and the price of electricity stabilizes, the unchecked growth of solar and other non-bypassable programs will increase and become a much more significant part of a bill, particularly since these programs essentially become a permanent part of rates.

Cross-Subsidization of Solar Programs Penalize Non-participants and Contributes to an Unreliable Electric Grid

AIM shares the goals of the Administration regarding clean energy. However, virtually all the savings (except for wholesale fuel costs) attributable to solar installations are basically a transfer from non-participating ratepayers to those who have solar, increasing costs for those who may not be able to take advantage of solar programs. While the easy answer is to encourage more solar, in fact, the viability of the program depends on this inequity. If everyone took advantage of solar programs, there would be no ratepayers left to pay the cross-subsidy.

This inequity is leading to an unreliable electric grid. As solar programs increase, there are less customers to pay the cost associated with maintaining the distribution and transmission system, which is still required to be ready willing and able to serve the customer when the sun is not shining. Additionally, some customers are not paying their fair share of other social costs which have been embedded in distribution rates over the last several decades, causing a massive shift in who pays for programs which serve low-income customers and support other societal programs. This additional cost then leads other customers to find ways to reduce their use, including self-generating through combined heat and power, a downward spiral that is getting even more pronounced as these technologies become cheaper.

Therefore, as part of the update of the solar program, there must be an acknowledgement that those who are still "connected" to the grid must pay their fair share of maintaining the grid that they in fact rely upon.

A Transparent Solar Program Based on Sound Economic Principles will Bring More Opportunity to the Commonwealth

This report should serve as a guidepost for changes to the solar program as it identified several areas that need attention to make the program more equitable. We urge you to look beyond easy answers. In fact, we urge you to look beyond the concept of net-metering as currently structured to encourage solar development. There may be other cost-effective ways to encourage solar development that do not rely on unfair and costly cross-subsidies.

We also urge you to resist the urge to make any short-term changes to the current program, including raising net-metering caps, until a comprehensive review of the current program can be accomplished and a plan for future growth can be implemented. Within this report there is clear data which shows that the current system is working best for solar developers and investors, at the expense of business trying to build and expand their businesses without the benefit of overly generous cross-subsidies. Changes may result in fewer solar jobs in the shop term. However, the benefits of a well-run sustainable program based on sound economic principles will in the long run be better for our economy and the ratepayers of Massachusetts. And lower electricity costs overall will result in more sustainable job prospects throughout the state.

Paul Brennan, III, Designee of the Attorney General

Market forces coupled with innovative green policies have spurred solar megawatt deployment across the Commonwealth, creating thousands of new jobs. The clean energy sector remains vitally important to our low carbon future. Going forward, we must ensure that our solar and clean energy industries continue to mature and ultimately thrive, independent of the policies and programs that have helped launch their success.

To that end, we must work towards better coordination among the variety of innovative green policies and programs, and the incentive payments, which all aim to benefit electric customers, solar development, and the Commonwealth. We must look to electric ratemaking tools and solar policies and programs that capture those cost effective solar opportunities available for all customers. We must advance these policies and programs wisely and in a transparent manner, ensure that benefits inure to customers, and strive to minimize any impacts and cross-subsidies especially for our most vulnerable low-income customers and businesses. In doing so, we will move the Commonwealth towards a sustainable and balanced solar market.

Any allocation of distribution costs throughout the system must be consistent with established rate design principals as envisioned by the Task Force. Further, we must pay careful attention to any potential adverse impacts on certain low usage customers and energy efficiency market incentives. As we move forward, we should also consider the establishment of alternative rate mechanisms, such as a rate class that would appropriately value the contributions of distributed generation and consider distributed generation's load profile and system use. Such a rate mechanism could take many forms, including a two-part tariff separately measuring consumption and generation, or more complex pricing structures that appropriately take into account imports, exports and demand.

Establishing the next generation of net metering and solar policies and programs must be a stepping stone on the way to creating a more level and consumer-focused playing field for all demand-side resources utilizing the grid. Anticipated modernization of the electric grid in Massachusetts along with a move towards an electricity rate structure that better reflects the cost to serve and value of energy generated by distributed generation will help the Commonwealth move away from an outdated utility-centric service model that only rewards more and more infrastructure investment rather than innovation and efficiency. The work must continue to be done in an open and transparent process, with regular reviews of the various programs and incentives to ensure their continued efficiency. We must continue to seek savings for ratepayers, bring all stakeholders to the table, and strive for balanced solutions.

Eversource Energy, Camilo Serna

Eversource believes clean energy is needed in Massachusetts and has and will continue to be committed to help the State meet its goals in a cost-effective manner. Eversource believes that solar energy policies should balance the following three objectives:

- Minimize customer bill impacts and protect the interests of non-participating customers
- Ensure there is a fair contribution for the use of the distribution system
- Provide incentives that are fair, market-based, transparent and fairly distributed

Eversource has been pleased to contribute to the work of the Net Metering and Solar Task Force and continues to stand ready to support cost-effective solar programs. Eversource wishes to provide comments around five specific areas:

1. Total Solar Costs Impact

Eversource highlighted throughout the entire process its concerns about the current and forecast cost to ratepayers associated with reaching Massachusetts' solar targets and the impact that these costs will have on its customers, especially those that do not participate in the solar programs.

Eversource's analysis indicates that Massachusetts is currently paying for solar at well above market prices. Currently, Massachusetts customers are paying more than 60 cents/kWh for solar electricity. At the same time, wind generation has been purchased for around 8 cents/kWh under long-term contracts and, nearby, Connecticut is supporting new solar projects for less than 25 cents/kWh.

Given the current trajectory, Eversource and National Grid customers will be spending close to $3.8 billion in solar between 2015 and 2020, at a rate of more than $600 million per year, which is clearly unsustainable. Of this, about two thirds of the costs are related to supporting the solar renewable energy credits (SREC) and one third related net metering. Consultant statements support this by indicating that "current combination of SREC policy and net metering framework is providing large margins for a diverse array of project types and participants".

Eversource contends that this level of investment is not warranted and believes there are better mechanisms to achieve similar clean energy goals, at a much lower cost. For example investments in other clean energy resources can reap greater environmental benefits, given those resources greater capacity factors, at a fraction of the cost. In addition, there are significant unintended consequences when investing in solar due to the need for additional generation to back solar power when is not producing, as well as the increased integration challenges and costs faced by distribution companies in order to manage the intermittency associated with solar generation.

2. Current Solar Incentive and Compensation Framework Flaws

Massachusetts' incentive structure for solar relies on two mechanisms: net metering credits and SRECs. Both mechanisms need to be completely revamped in order to meet the State's solar goal in a more cost-effective manner. More specifically, Eversource believes the existing net metering approach is not well designed to support increased deployment of distributed generation and solar in an efficient, cost effective and sustainable manner.

Through net metering, solar customers are avoiding paying for some or all of the distribution services (i.e., resiliency, maintenance of grid), yet receiving even more value from the grid (i.e., reliability, start-up services, ability to transact and monetize solar energy). Further, solar customers are avoiding other non-T&D costs used for other public policy programs such as the renewable and energy efficiency funds, low income programs and many others.

These costs that solar customers are being credited for, even though they are being incurred to operate and maintain the grid for their use, must still be collected by the electric utility company and are increasing the costs to non-solar customer bills. Furthermore, virtual net metering (VNM) has created a significant cross subsidy mechanism and administrative burden. VNM's issues include the transfer of payments from generator to customer accounts that has no relation to actual load reductions.

The issues associated with net metering and VNM are an irrefutable fact highlighted by the consultant when it concluded that "T&D charges avoided by onsite generation and virtual net metering charges are significant in all scenarios and it is understandable that utilities are concerned about the impacts of the current incentive framework".

3. Net Metering Revamp

The Department of Public Utilities' (DPU) long-standing rate design goals are efficiency, simplicity, continuity and fairness. Net metering as it currently stands violates these principles. Proper cost allocation is essential to fair ratemaking and the avoidance of hidden cross-subsidies. In order to ensure that net metering or other mechanisms do not result in cost displacement among customers or impose undue costs on all non-distributed generation ratepayers, regulators must ensure that rates reflect equitably the benefits and costs of distributed generation. Deviations from this policy lead to distorted incentives and diseconomies that are not sustainable over time.

A rate design based on service provided at the customer's delivery point would be more transparent and equitable than that provided under a net metering scheme. Adaptation of separate metering at the delivery point and at the point of production will allow provide greater transparency and explicit evaluation of the costs of providing service and value of generation at these service locations, and help inform the extent to which service characteristics of customers with solar are distinct from other customers. Furthermore, this information will help inform the basis for a separate rate class for customers with solar, or whether cost of service characteristics for certain components of service (e.g., distribution and/or transmission) warrants a separate or identical rate design.

4. Competitive Procurement for Large Scale Solar

SRECs have been very good at supporting the development of solar resources, but Eversource is concerned that this is mostly due to the availability of customer-funded SREC revenues that ultimately far exceeded what was or is necessary to support solar development in the state.

Eversource has been pleased with the results of long-term competitive programs it is running in Connecticut where solar RECs have been procured at 40% less than those in Massachusetts in 2015. A similar, thoughtfully designed program in Massachusetts will provide for transparent pricing, will bring down the cost of incentives and will provide for an orderly market development and evolution.

5. Net metering caps

Eversource believes the topic of net metering caps does not need to be addressed until the overall policy structure is updated, and further believes there should always be a system of checks and balances to ensure costs to ratepayers are reasonable and justified.

Massachusetts can still meet its goal of 1,600 MW for solar within the current cap structure as evidenced by the consultant analysis. There are still more than 250 MW available under caps throughout the state, and many systems are not subject to caps.

Maintaining the current cap will not impede solar development. On the contrary, the number of applications and proposed MWs for interconnection are materially higher than they were last year at this time, when the cap had not been reached. This indicates that there is ample compensation through the SREC program and robust activity under the current regime without expanding net metering caps.

IBEW 103, Lisa Podgurski

Value of Solar /Comprehensive Benefit Cost Study

We would recommend that the legislature consider reconvening the Net Metering Task Force to determine the scope of the Value of Solar Study and choose a consultant selected and approved by the task force. This study will also be integral to determining net metering compensation.

Incentive Delivery Mechanism for Large Scale Distributed Solar

We strongly urge the legislature to implement a Declining Block Incentive that can adjust to and respond to market conditions.

A Declining Block Incentive is transparent and predictable allowing optimal investment conditions within the solar industry. This incentive model will create a self-sustaining market and industry. California has had much success with a similar program and continues to thrive. Massachusetts was number four in the United Sates this past year for solar growth. We want to see that growth in the solar sector continues.

Unlike the Declining Block Incentive, a Competitive Procurement Model (CPM) will only create an unreliable landscape within the market. Investors and developers need to have a level of certainty and transparency when investing in projects early on. Here are some reasons it will not be advantageous to the industry:

- The CPM replaces the value of solar with a price set by competition rather than through a process that more closely reconciles it with the value of solar, which brings it to the market and market based investment returns.
- The CPM reduces the ability to target policy-driven segments of the market, such as low income housing, community solar, carports, rooftops and others while favoring larger scale projects that can simply sell at wholesale and achieve minimum hurdle returns.
- CPM will essentially end the ability for both private and public entities to rationally and in an organized fashion engage in the long term procurement of solar given that developers will not be able to reliably offer pricing to customers until after capacity has been awarded under such a program.
- CPM makes Community Solar almost impossible to reliably deploy considering the long planning and lead times related to the development and marketing of these projects, as well as the higher costs related to the development of these types of projects.

Net Metering Caps

The Net Metering Caps must be lifted immediately. National Grid, one of the largest territories, has hit both of their caps. The solar industry is going to come to a grinding halt. Without the assurance of net metering, investors and developers will not continue to invest money in this state and the solar industry. If that happens, jobs will be lost. The solar market has created over 12,000 jobs. We do not want to see jobs lost because the legislature chose not to raise the caps to advance the solar industry at a time when we are still climbing out of a recession and dealing with a jobs report that did not give us the numbers we anticipated.

Here are some additional points on the potential detriment to the solar industry if the caps are not lifted immediately:

- Critical market segments such as community shared solar, low income housing, landfill and brownfield development and much of the municipal solar market are all dependent on net metering as a means of allocating credits to off-site load. Without such a bill crediting mechanism, these market segments will not be viable.
- The lack of net metering will significantly change the composition of the Massachusetts solar market and limit market diversity.
- Achievement of the commonwealth's solar goals will be significantly delayed. The consultant analysis presumes that exempt (under 25 kw) market and small rooftop behind the meter solar installations can increase fourfold to make up for larger net metering projects that rely on net metering while the Federal ITC for residential is scheduled to go to zero, which stretches credulity.
- The commonwealth's solar goals will be achieved at higher cost as market development shifts away from lower cost installations to smaller rooftop systems.
- The window of opportunity for Massachusetts to leverage the 30% Federal ITC is closing quickly, and if prompt action were not taken to lift the cap, this financial support for solar in Massachusetts would be lost.

Knowing that it could take the legislature some time to sift through this report and form their conclusions and create a policy, it is imperative that immediate action is taken to raise the caps for relief. While speaking with various developers over the past few weeks there has been a common theme and that is panic. They are already seeing projects halted, investors walking away and many are still submitting applications to National Grid hoping and praying other projects in the queue fall apart so theirs can move up in the queue to obtain the net metering benefits. Should they not then they will pull their applications unless the caps are lifted. This is no way to create stability in the market and sustain growth.

“Grandfathering” of Current Incentive Programs and Net Metering

We strongly believe that existing participants in the SREC programs and those that take part in net metering should be “grandfathered” and be able to retain those benefits. The residential community as well as the large-scale solar community invested in their systems based on our existing statute and regulations. Although no promises were made on the value of those net metering credits and we understand that can fluctuate, the basic incentive structure should not be changed on them. They may not have made that investment if they knew ahead of time that they structure may change or completely go away.

<u>Eric Krathwohl – Appointee of Senator Bruce Tarr</u>

<u>Overview</u>

This Task Force member is pleased to see the extent of consensus that has been reached on many issues that are both complex and have important implications for various stakeholders. I hope that the Task Force efforts, informed and supported by extensive work by the consultants, will prove useful to the Legislature and help achieve legislation that establishes a framework to foster the solar industry in the Commonwealth to the goal of 1600 MW of solar facilities installed with continued growth beyond on a basis that is as economic as possible. This statement seeks to provide a general perspective on the process, as well as expanding on positions taken on certain issues. First, there are **significant benefits from solar that are well-acknowledged** and which justify serious consideration to ensure that solar development is properly compensated and is fostered through supportive policies. These benefits to electric customers include: 1. Increased diversity of the resource mix; 2. Significant transmission and distribution cost savings – even netted out after the costs of interconnection of solar; 3. Reduction in the cost of capacity. Also, there are significant other macro-economic benefits to citizens of the Commonwealth, including jobs, tax revenues and emissions reductions from generation resources. Several studies, including the consultants’ detailed cost-benefit analyses provide detailed calculations of these significant economic benefits (showing net present values (“NPV”) exceeding $14B, or about 20 cents/kwh NPV) that result from installation of solar. Accordingly, compensation or economic support to solar can and should be reflected in rates, Solar Renewable Energy Credits and tax credits.

It is acknowledged (and the consultants’ report shows) that electric **customers not participating directly in solar programs will be supporting solar development** through their electric rates on a net basis – even after considering the direct benefits to such customers. That some utility service customers (or taxpayers generally) will be supporting some program that is deemed a public good without receiving direct benefits is by no means unique to solar. While of course, significant efforts should be made to keep the costs of the Commonwealth's solar programs as low as possible while still achieving the desired goals, reduction of cost impacts on non-participants should not compromise sound program design or otherwise undermine the achievement of the goals or fostering of the solar industry. Rather, significant efforts should be made to **democratize solar** to the greatest extent possible, i.e. make solar available to as many electric customers as possible. This can be done through programs that foster projects including community shared solar and solar in low income housing. As the consultants explained, once the caps on net metering are reached, these sorts of projects (and certain efficient large scale installations) become unfeasible. This is an important point when considering net metering caps immediately, but also over the long term. In the same context, **diversity of projects and breadth of participation are important goals** and those are affected by decisions on the framework. Achievement of these goals may well require considerations beyond a simple cost benefit analysis.

Specific Issues Upon Which Consensus Was Not Reached

1. Net Metering Caps. There is some consensus that if the pricing relevant to solar were right, caps would be unnecessary. Not all Task Force Members support immediate lifting of caps. However, there is a serious short term problem where the public and private caps in the National Grid service territories are already filled. It is not a sufficient answer that solar development can proceed in the other half of the state or that rooftop solar will pick up the slack. Simply, solar development should occur where it makes most sense considering efficiency, cost effectiveness and other factors. Such a severe curtailment of the possibilities for development cannot help but have a significant adverse effect on the important solar industry, including jobs in the Commonwealth and other economic benefits. Therefore, I have supported immediate cap relief, to the extent deemed proper.

Nonetheless, as a lawyer very familiar with the **DPU ratemaking process** through handling of over 50 rate cases, I certainly agree with the fundamental principle of every electric customer paying the fair cost for the services received and that such principle is relevant to whether or how much caps are raised. (As discussed below, that concept is also relevant to net metering compensation as well). In the long run, if solar pays its fair share (after full consideration of the benefits solar provides), caps are unnecessary. Those calling for refraining from cap relief now make a mistake to assume that solar costs exceed benefits. That assumption is not only unproven, it is contrary to the consultants' report. Without an open review of a comprehensive study of the benefits and costs of solar, solar development in any area should not be halted for the significant period it will take to perform and review a comprehensive benefit cost study. A thorough review by all interested parties in the context of a hearing before the DPU is entirely appropriate, but should not be a precondition for some limited, interim cap relief.

2. Competitive Solicitations. This Task Force Member recognizes the benefits of competitive solicitations – particularly in terms of reducing costs of projects bid into such solicitations. However, I believe that a better approach for most projects is a declining block incentive ("DBI") mechanism which would also incorporate the salutary benefits of competition. A DBI mechanism will provide several other benefits including a market responsive incentive level, certainty and predictability of price available to solar generators and overall costs of the program. Moreover, without the starts and stops and costs of the competitive solicitation process, the DBI will foster more level rates of development and constant employment. Therefore, I support the policy recommendation of using the DBI. Nevertheless, for the largest projects, competitive solicitation may be appropriate.

3. Net Metering Compensation. As noted above, appropriate compensation must consider benefits, as well as costs, of solar. To ignore the benefits noted on page 1 above, and to limit compensation to solar generators to the "generation" rate as suggested by the utilities and AIM is contrary to the basic ratemaking recognition of cost causation and is inconsistent with the goal of fostering the solar market with its widely recognized benefits. Also, the compensation structure should give appropriate consideration to the various "categories" of solar projects as referenced on pages 5-6 of the Task Force Recommendations. The majority of solar projects will not be utility procurements, so compensation should not be limited to the cost of energy efficiency or other resources procured by the utilities. Not only do the utilities seek to "compare apples and oranges" in urging such a standard, but they seek to impose a framework that simply is not applicable, intrudes on the market and would stifle extensive benefits. Further, it would be a mistake to change the availability of net metering for existing projects. Investment decisions were made in reliance upon state assurances of availability of net-metering (with recognition that the rates could change), so serious damage to credibility of the Massachusetts solar program and market would result if the playing field were moved before a reasonable opportunity to recover investments occurred. Current harm to existing generators and future harm to the potential for investment in solar in Massachusetts would result from changing the rules now. In contrast, future investments made after adoption of a new statutory/regulatory framework could be made subject to a different compensation scheme without such risks.

National Consumer Law Center, Charles Harak

The National Consumer Law Center (NCLC) is a non-profit organization with the mission of advocating on behalf of low-income people on a range of consumer and economic issues. In particular, we seek to ensure that low-income families can afford the basic energy supplies (including electricity) they need to survive. While we actively support energy efficiency programs and renewable technologies that can provide benefits to low-income households, we are always mindful of the potential cost burdens that these households can face if program designs do not carefully balance benefits and costs.

Massachusetts has enjoyed some of the fastest growth in installation of solar photovoltaic (PV) power in the country, as a result of policies consciously adopted to promote PV. On a size-adjusted basis, we've installed more than 10 times the amount of solar PV as Texas, despite that southern state enjoying far more sunshine, and it's now clear that we'll easily meet not only the 1,600 MW goal contained in Section 7 of Ch. 251 of the Acts of 2014, but also that we will have installed 2,500 MW by somewhere around 2023 under any of the solar incentive scenarios considered by the Task Force. The benefits are far-ranging: solar PV is an important tool in helping us meet our greenhouse gas reduction goals; investments in PV keep dollars in the state that would otherwise flow elsewhere to purchase natural gas used in electric generating plants; those who install PV enjoy substantial protection against cost increases in the price of utility-delivered electricity; and PV investments have helped build a vibrant and growing local solar industry that supports good jobs here in the Commonwealth.

But as the industry has matured, it is important to reconsider policies that were developed at a time when it needed substantial assistance to get off the ground. When installed PV capacity was small, providing substantial assistance to PV made sense – and had almost no discernible impact on ratepayers who did not install PV. The current panoply of policies that provide assistance to PV – primarily, the "SREC" (solar renewable energy credit) requirements and allowance of "net metering" – are quite expensive and more generous than almost any other state in the country, including states that are also enjoying rapid growth in solar. In response to a request from DPU Chair Angie O'Connor, Eversource and National Grid provided data showing that the current net metering and SREC I & II policies will result in a shift of over $600 million in costs in 2015 alone, onto that vast majority of ratepayers who have not installed PV[7]. The Task Force consultants have proposed various designs for a new "SREC III" under which the state will reach 2,500 MW of installed capacity by early in the next decade, and at lower cost

[7] Of course, ratepayers also receive benefits from having solar PV added to the system, but those benefits were not quantified in the data responses by Eversource or National Grid.

than the current SREC II regime. NCLC encourages the legislature to ensure that our solar support policies are not more expensive than they need to be, and do not require cross-subsidies from ratepayers who do not install PV to those who do.

Two important and closely related issues with which the Task Force has wrestled are the rules governing net metering, and the idea of establishing minimum bills, each of which we are required to address under Ch. 251, § 7. Current net metering rules compensate a customer who generates electricity at the same rate per kilowatt-hour (kWh) that the customer pays the utility when buying electricity. This arrangement was developed to help accelerate the growth of solar PV and avoid the metering and other problems that would arise if, for example, the customer had to buy all electricity at the company's published tariff rate, but be paid for electricity generated at some different rate. But net metering is not based on any study showing that the price at which a utility sells electricity to a customer should be identical to the price at which the customer sells electricity to the utility – in fact, it would be quite surprising if those prices should be the same. When a customer buys electricity from a utility, the price includes not only the cost of the actual electricity delivered, but a bundle of other costs: the costs of electric meters, stations, distribution poles and lines, and central monitoring/control equipment, and the labor/administrative costs for repair and maintenance of the system, billing, and customer support. When a customer sells electricity to the utility, the only thing directly delivered is the electricity itself.

NCLC readily acknowledges that solar PV can provide a range of other values: PV may somewhat reduce the need for expensive investments in generation, transmission and distribution systems, and unquestionably provides significant environmental benefits. But this does not mean – contrary to the assumption behind net metering – that the price to be paid a solar PV generator is necessarily identical to the price the utility charges a customer purchasing electricity. NCLC recommends that a study of the value of solar PV-generated electricity be conducted. This study may show that PV generators are being overpaid – or underpaid – under the current net metering regime. The price paid to those who generate electricity via PV should be set in accordance with the results of such a study. NCLC believes that the DPU should consider adopting a separate tariff for those who self-generate electricity as this would make it far easier to track the costs and benefits attributable to these customers and get the pricing right.

Because there is the perception among many that the current net metering regime may not fairly compensate utilities for the costs of their infrastructure and distribution systems, Ch. 251, § 7 directs the Task Force to consider minimum bills "as a mechanism to support a reliable distribution system." The reason minimum bills should even be considered is precisely because of this perception that net metering does not fairly compensate utilities for the costs of the distribution system that all customers need, including customers who install PV. The better fix, therefore, is to make sure that the price solar PV customers are paid is right, rather than layering minimum bills on top of a net metering regime that still needs fixing. NCLC strongly opposes minimum bills for two reasons. First, to the extent that minimum bills provide revenues to the utility, the kWh charges will have to be lowered because the company's total revenues are fixed by the DPU. As more revenues come from minimum bills, less can come from the kWh charge. This sends a bad signal in terms of the state's energy policies: that investments in energy efficiency and renewable energy are worth less. Second, as demonstrated below, per customer consumption of electricity in Massachusetts is, on average, lower among elderly, low-income and minority consumers. Imposition of minimum bills – depending on the precise design – are thus most likely to adversely impact the very customers the state should most want to protect. Minimum bills are this bad public policy from either an environmental or low-income perspective.

Massachusetts Household KWH by Poverty 150%, Age of Householder and Race of Householder

Household income at or below 150% of poverty line	Total Site Electricity usage, in kilowatt-hours, 2009	Age of Householder	Total Site Electricity usage, in kilowatt-hours, 2009	Householder's Race	Total Site Electricity usage, in kilowatt-hours, 2009
No	6,056	Less than 65	6,027	White	5,883
Yes	4,222	65 or More	4,522	Black or African/American	4,323
Total	5,686	Total	5,686	Asian	5,177
				Total	5,686

National Consumer Law Center, April 2015
Source: U.S. Energy Information Administration - 2009 Residential Energy Consumption Survey

In order that the work of the Task Force should affirmatively help low-income households, NCLC urges the legislature to make sure that Community Shared Solar (CSS) will remain economically feasible in light of any changes made to current policies, whether through more favorable net metering rules that apply only to CSS or through other policies. Low-income households are extremely unlikely to participate in solar PV except through mechanisms like CSS because they are disproportionately renters (not owners) who have no ability to install PV on their own homes. Even those low-income households who do own their homes generally cannot afford the up-front capital payments or monthly lease payments that would be required.

NCLC is pleased that we have been able to participate in the Task Force. Many people have devoted a tremendous amount of time and thought to this effort, which should help guide the legislature as it considers changes to current policies.

National Grid, Amy Rabinowitz

National Grid is a strong supporter of solar energy, and sees great opportunities to make solar successful in Massachusetts while lowering costs for customers. Today, with the current net metering caps and solar carve-out program, we project that the cost of providing net metering and solar incentives for 1600 megawatts (MW) from 2014 to 2020 is almost $2 billion for National Grid customers, and more than $6 billion for customers of investor-owned utilities across the state over the life of the programs. Massachusetts pays more for solar output than any other state, with the current compensation ranging from $450-$600 per megawatt-hour, which is considerably more than it needs to be to meet our solar goals. Current solar policies will add about 1.5 cents to every kilowatt-hour used for nearly the next decade. The net metering approach currently in use requires our customers without solar to shoulder an inordinate share of these costs, while enabling customers with solar to by-pass paying towards our electric distribution system which they use 24/7, whether their solar unit is generating or not. Massachusetts should transition as soon as possible to a long-term, sustainable approach that is competitive, efficient, and fair.

Net Metering Caps and Costs:

There is no need to adjust the current net metering caps. Only National Grid has reached its net metering caps; elsewhere, there is still approximately 250 MW of net metering capacity available. National Grid reached its net metering caps in March of 2015, and continues to receive significant numbers of applications, a greater volume of both applications and proposed MW than last year at this time. In addition, applications for residential and small solar systems, which are not capped, nearly tripled, with 3,075 applications (representing 18 MW) received already in 2015 compared to the same time period last year.

There are several problems with net metering as in place today in Massachusetts. First, it overpays customer-generators because they receive credit for their energy at the retail rate, plus credits for distribution and transmission. These latter two are services that net metering customers do not provide; instead, they rely on National Grid and the electric system 24/7, for example, exporting electricity while the sun shines, importing electricity when it does not, and relying on us to administer the distribution of benefits to others, such as by allocating “virtual net metering credits,” where they use the distribution system and the utility's administrative services for free. Second, net metering shifts the costs of these net metering credits, less any revenue received for their excess energy, onto customers who do not net meter. National Grid's customers bore $34 million of costs associated with net metering in 2014, but this cross-subsidy will reach $64 million in 2015 and continue to grow each year. Between 2014 and 2020, we estimate that National Grid's paying customers will see net metering impact their rates by more than $600 million even without raising the net metering caps.

Alternative Policies:

A new framework needs to replace net metering and SRECs. Net metering, alleged by some to be "rough justice" compensation for the benefits of solar, is based on an unproven hypothesis that solar is providing services to the electric system, and any services that it provides are of equal value to retail rates. In addition, SRECs are a separate incentive payment that is meant to compensate generators for the environmental and other renewable energy attribute benefits of solar energy. Today, the SREC payments are too high because they are driven by administratively-determined formulas and price supports. As a result, they do not enable us to seek lower costs from the solar industry.

Net metering, and particularly "virtual net metering," needs to be addressed as soon as possible. Payments to solar hosts should be based on the energy that they produce and any other system benefits to the distribution grid that are known, measured, and verified to actually reduce system costs for all customers. These credits should not include distribution and transmission rates, nor societal benefits, nor unproven services to the system. The best framework would provide solar developers with long-term payments that would encourage low-cost financing of their projects, and compensate them for any services they provide that are less costly than alternatives. This should be done without creating artificial "energy savings" from virtual net metering that are paid for on the backs of other customers.

Incentives for Solar Through Competitive Bidding:

National Grid is routinely required by state regulators to use open and competitive bidding in order to get the best prices for customers. The Commonwealth uses open and competitive bidding for its purchases. Other generators in New England bid into a regional market to sell their electricity. Open and competitive bidding, with a maximum or "ceiling price," is the best method for the Commonwealth to have procurement for solar energy, renewable attributes and related products because they: 1) create transparent prices from an active market; 2) ensure that customers pay only what is necessary; 3) allow for the management of total expenses, and volume of purchases; and 4) ensure "serious bids" through binding proposals, and non-performance penalties.

Instead of contracts, tariff payments can provide secure and simple funding for solar hosts, and competitive bidding should lower costs paid by all customers. In Rhode Island, this construct has resulted in dramatically lower prices. While the cost of developing solar has rapidly declined across the country and worldwide, Massachusetts' policies have kept the prices artificially high. The Commonwealth should advance policies that push the solar industry from a protected market into a competitive one, to reduce their costs to customers.

Comments on the Consultants' Report:

While we appreciate the hard work of the consultants, we have a number of issues with the final version of the consultants' report. In early drafts, National Grid recommended changes to remove errors and bias, which were not adopted (e.g., competitive bidding was characterized as disruptive to the development of a stable industry with steady job growth, and can also result in "speculative bidding"). Competitive bidding is relied upon by businesses and governments because it is proven to reduce costs, which is clearly a benefit for purchasers, or in this case, paying customers.

Review of the modeling and scenarios presented the most serious challenge, and Task Force members were given very limited time to assess the final version. While National Grid cannot endorse the consultant's recommendations and analysis, we plan to continue to verify and assess the models presented. Our initial review suggests mischaracterization of system costs as benefits, the omission of the cost of capital as a cost, and no consideration of the costs of economic and job losses from overly expensive solar programs. Also, we disagree with the assumptions about the benefits of avoided distribution and transmission costs, which should be analyzed, not assumed, using system-specific information. However, the modeling showed that, in all scenarios, non-participating ratepayers pick up the tab, with a benefit cost ratio of less than one.

Finally, despite our requests, the report does not offer an "apples-to-apples" comparison of the total payments made for solar output by other states operating solar incentive programs. It gathers and presents useful information, but it is a mix of numbers and characterizations that are not comparable. It is another lost opportunity. A simple price analysis could have shown, in a transparent manner, how much Massachusetts pays for solar programs compared to other states.

Conclusion:

Along with the Net Metering Task Force report, the Legislature and the Administration have more information to review in reforming the laws and regulations for the Commonwealth's solar programs. Policy makers must examine the benefits and costs for all Massachusetts residents, especially those who cannot directly benefit from solar ownership. National Grid acknowledges the environmental benefits and energy supply diversity associated with solar development. However, as evidenced by the experiences in other states, there are opportunities to achieve those results at far lower costs that ensure greater benefits for everyone in the Commonwealth.

New England Clean Energy Council (NECEC), Janet Besser

INTRODUCTION

NECEC commends the Net Metering and Solar Task Force Chairs and members for their diligence and collaboration in this effort. The topic of net metering and solar incentive policy is complex and stakeholders hold strong views. The quality and tone of the discussion has been positive and took place in an open and transparent process. The work of the Task Force has laid a foundation for the next steps needed to ensure a robust solar industry in Massachusetts that will continue to create jobs and attract investment, secure and diversify our energy supply and reduce the environmental impacts of energy use and production.

The Task Force deliberations took place in a broader context of concern about high electricity costs in Massachusetts and across the region. The Baker Administration and policymakers generally are looking for ways to reduce energy costs for customers, businesses and industries. NECEC shares the goal of making energy more affordable for customers now and over the long term. Costs, however, cannot be viewed in isolation or only in the short term. The costs of solar and other renewable energy resources constitute a very small portion of customers' electricity rates.[8] Dollars spent on solar are also an investment in the Commonwealth's energy and economic infrastructure that stays in Massachusetts. This investment is earning a positive return in jobs (12,000),[9] investment ($2.37 billion),[10] and energy, peak load and greenhouse gas (GHG) reductions. Solar energy is clearly a critical and valuable component of an energy platter that will satisfy our appetite for electricity.

That said, the Task Force was charged with reviewing "the long-term viability of net metering and develop[ing] recommendations on incentives and programs to support the deployment of 1,600 megawatts ("MW") of solar generation facilities in the Commonwealth." Implicit in this charge was consideration of actions that could reduce the costs of solar programs in Massachusetts and ensure that those costs are allocated fairly, while achieving the 1600+ MW of solar. This would further enhance the value of solar for the Commonwealth at large.

[8] Renewables/other charge is not even visible in graphs from "Analysis of Costs and Benefits – Update and Preliminary Results Draft (041515)," slide 27, presented at April 16, 2015 Task Force Meeting.
[9] Massachusetts Clean Energy Industry Report, 2014.
[10] Investment 2010-2014, SEIA.

PRESERVE AND ADVANCE SOLAR IN MASSACHUSETTS

Immediate Term Action Needed

NECEC's immediate action priority is to raise net metering caps now and through the end of 2016 in order to prevent further disruption of successful solar industry projects in Massachusetts, an industry that is delivering economic, energy and environmental benefits to the Commonwealth's citizens, businesses and industry. The caps have been reached in National Grid's service territory and will be reached in other service territories before a new solar policy framework can be implemented. The Task Force recommendations support "a policy to maintain the growth of the solar market to 1600 MW and beyond" and state that a "[p]olicy design should promote the orderly transition to a diverse and self-sustaining solar industry." One of the first steps needed in this transition is an increase in the current net metering caps now. A majority of the voting Task Force members recommend that "[t]he Legislature should raise the net metering caps … to avoid adverse consequences that would otherwise occur to solar development during the pendency of the legislative review and administrative implementation of long-term sustainable solar policies." Acting now can avoid the loss of jobs, investment, tax revenue and federal incentives, and substantial energy and environmental benefits. Acting now will also enable solar development to contribute to achievement of the Commonwealth's GHG reduction requirements. While a long-term policy framework to support the orderly development of solar is essential, the Legislature should take this vital interim step and address the net metering caps immediately so that solar development and the jobs and investment it brings to the Commonwealth are not disrupted.

Action Needed for the Long-Term Solution

NECEC's priority for the long term is establishment of a "sustainable" policy framework – one built on sound economics and designed to achieve energy and environmental policy objectives efficiently and cost-effectively. A long-term sustainable framework rests on fair compensation to solar customer/generators for the value they provide to ratepayers, the distribution grid and the Commonwealth as a whole and fair compensation to distribution companies for the service they provide. With fair compensation both ways, caps on net metering can be eliminated. The Task Force recommendations make this point: "Specifically, [a majority of] the Task Force Members believe that caps on net metering are no longer necessary where: 1) All customers, including solar generators, are paying their fair share for grid services; and 2) All customers are receiving the fair value for the services and products they supply to the grid and Commonwealth at large."

To establish fair compensation for solar a comprehensive and transparent benefit/cost analysis or "value of solar" study should be undertaken, which identifies the broad range of benefits and beneficiaries, as well as the costs associated with solar development over the long term. The Task Force supports conducting such a study in a timely manner, recommends that it be led by DOER and the DPU, and that it be used to inform appropriate compensation for solar.

To determine fair compensation for use of the distribution grid, a fully adjudicated rate case, revenue neutral rate design case, or equivalent data and information in the distribution companies' grid modernization plans should be filed. Proposed rates should be consistent with long established ratemaking principles and take into account public policy objectives, including but not limited to pursuit of all cost-effective energy efficiency, renewable energy, demand response/reduction, greenhouse gas (GHG) reduction, system efficiency, and reductions in electricity price levels and volatility. NECEC notes that grid modernization and time varying rates are additional tools to advance these objectives and enable DER integration in a cost-effective and efficient manner to capture its benefits for all customers.

ENSURING A SMOOTH TRANSITION

Continued growth of the solar market in the Commonwealth requires policy and regulatory certainty. Developers and investors will not bring their business to Massachusetts if they are not confident that the deals they strike and commitments they make will be honored. While it is appropriate for the solar policy framework to evolve as the solar industry matures, program and compensation mechanism changes must apply prospectively. The majority of the Task Force recognizes that It would be very disruptive to require existing net metering facilities to transition to a new framework and recommends that "[p]rojects in operation or those with Net Metering Cap Allocations that were obtained prior to any new policy framework being adopted shall receive compensation/credit under the current policy framework." Existing net metering customers should be allowed to transition to a new framework and could be encouraged to do so. A smooth transition to a new solar policy framework also requires sufficient notice to the market, which the Task Force recognized, stating, "To enable smooth, low-cost transition to a new policy structure, visibility about the details of the new structure should be provided several (6-8) months in advance of the policy implementation date."

NEXT STEPS IN 2015

NECEC looks forward to working with the DPU, DOER and the Legislature on next steps to ensure a self-sustaining solar industry that will continue to provide benefits to the Commonwealth cost-effectively.

NECEC believes that the best path forward is legislation this year that does three things:

- Provides net metering cap relief for the period of time required to review and make any necessary and appropriate adjustments to how solar is compensated through net metering;
- Directs the DOER and DPU to conduct a transparent and comprehensive solar benefit-cost study to provide the foundation for fair compensation to solar and any adjustments above; and
- Instructs the DOER to transition the solar incentive program to a more efficient incentive delivery mechanism.

Next Step Living (Geoff Chapin/Larry Aller) Individual Statement

There is strong consensus on the Task Force that solar is important for Massachusetts, and that solar growth to 1600MW and beyond should be actively supported. In developing the policy and further goals for solar in the Commonwealth, it is important to consider several factors:

1) Over 8,300 MW of generation will be decommissioned in the region over the next five years
2) The region's share of generation from natural gas has more than doubled to close to 40%
3) Shortage of natural gas supply has caused massive incremental costs to MA ratepayers. For example, **winter rates caused over $3 Billion in extra costs in just three months** this winter.
4) Additional gas supply would cost residents additional billions in infrastructure costs

We face the decision about how to evolve the region's energy mix during this next five years and beyond: Should we increase demand for natural gas by installing more gas generation when supply shortages are already causing billions in extra costs in just a few months, and spending additional billions funded by Massachusetts residents is being considered just to meet current gas demand? Or should solar and other sources be used and grown further to diversify our electric supply to provide lower and more predictable overall costs? If solar is to be utilized, Massachusetts will need to go well beyond 1,600MW just to maintain natural gas's *current* share of the generation mix.

In order to achieve state energy and solar goals, two issues are absolutely critical: Addressing the net metering caps immediately, and grandfathering current net metering policy for existing solar projects.

Immediate action to address the net metering caps is needed to preserve jobs and enable the Commonwealth's solar goals to be achieved cost-effectively. This action cannot wait for the overall process by the Legislature to review and establish long-term solar policy. The net metering caps are preventing solar projects from being planned and developed in the over 170 communities in National

Grid territory right now, and more caps will be hit between today and the implementation of the full long term policy. A majority of the Task Force members support action here.

The actions of the Legislature have created over 12,000 jobs as part of a strong and vibrant solar industry that is helping achieve a low cost and clean energy future for the Commonwealth. Without immediate action on the caps, many of these jobs will be lost over the next year and a half. If nothing is done, the long-term policy will be implemented, the Commonwealth will ask for companies and workers to achieve those goals, and few will remain to answer the call. These jobs will then have to be replaced at much greater cost, if at all, and Massachusetts will also be losing the opportunity for hundreds of millions in federal funding between now and when the federal ITC is set to expire at the end of 2016.

In addition to these considerations, solar investment should be continued and accelerated in the short term because **solar delivers clear, significant, and well-documented net benefits to the Commonwealth overall**. Multiple in-depth studies in ME, NY, CT, VT, MN, MS, and recently by the Acadia Center in MA show that solar provides significant net benefits to the electric system, and to the community overall – any claims that solar in Massachusetts is using grid services while being subsidized by other ratepayers are unsubstantiated.

Grandfathering current net metering policy for existing projects is absolutely necessary for both new and existing solar in Massachusetts. If this does not happen, practically no residents or investors will be willing to invest in solar in the Commonwealth, and many existing solar projects will face default or risk of default. Over 20,000 residents and investors have invested over $2B in solar in Massachusetts based on the existing policy structure for net metering. If they fear that such investments can be fundamentally destabilized by state policy changes at some unknown point in the future, they simply will not invest. Massachusetts will lose the jobs and societal benefits it has worked so hard to create through a strong and vibrant solar ecosystem, and will be at risk for billions in extra costs from natural gas and other generation to make up the overall and summer peak generation that solar would otherwise provide. The majority of the Task Force supports this grandfathering, and it should be an immediate action of the Legislature to provide confidence to financial investors that supply the capital necessary for solar projects to happen.

<u>Approach for effective and complete solar benefit/cost analysis :</u> Any long-term policy should be based on a full and complete understanding of all the long term benefits and costs of integrating solar into our energy system – at a grid level and at a societal level. Components to consider include: Avoided costs for energy, transmission, distribution, generation and reserve capacity, NG pipeline capacity, and CO_2

and other pollutant costs; fuel price and marginal market price reduction; economic development and other environmental and social value; and solar integration costs and grid services costs. There should be a broad and inclusive stakeholder process with opportunity to review, discuss and refine the components and technical details of such analysis. The team led by Karl Rabago and Richard Perez has deep experience doing this in Austin, Minnesota, Maine, and elsewhere, and can provide a legislative briefing on approach and considerations in evaluating the complete set of benefits and costs.

Community shared solar and Low income access as policy priorities : One of the primary principles of the Task Force consensus is that equitable access to solar, where feasible, is an important goal. Community shared solar and access to solar by low-income communities are foundational pieces of enabling this equitable access, and should be supported with policy structure and incentives as necessary to enable these emerging segments to offer the ability to participate in solar to the eight in ten residents who do not have a good roof for established solar offerings.

Another consideration to highlight is that given the limited amount of time, the Task Force was unable to have an in-depth consideration of issues related to low income access to solar, and how solar can be leveraged to proactively address energy affordability concerns in low income communities

Alignment of utility compensation with Massachusetts solar goals: While time limits prevented in-depth discussion of this topic on the Task Force, this is highly important for achieving Massachusetts' solar goals cost effectively. Options that would clearly align utility financial interests with the state's solar goals should be explored further. Options could include enabling the utilities to earn a return on investments in solar integration and grid storage, and performance incentives for achieving solar goals.

Risks of Competitive solicitation: While the goals of competitive solicitation are good ones, the real-world functioning of this approach often does not match the theoretical positives of delivering solar capacity cost-effectively that we are all trying to achieve. For example, the actual result of these systems is often *higher* costs and *lower* installed capacity, as few companies can afford to participate, undeliverable bids are made, and program delivery deadlines are missed due to uncontrollable issues such as delayed interconnection from the utility, often resulting in forfeit of the project deposit. Given these risks, a competitive solicitation should not be used, as the same positives and goals can be achieved by the market-adjusting incentive for large-scale solar described by several members of the Task Force in the Recommendations.

<u>Minimum monthly contribution</u>: We share the concerns of several other Task Force members regarding the risks of a minimum monthly contribution, including regressive impacts, negative impacts on energy efficiency policy and goals, and other political risks, while better than fixed fees or customer charges. Other options achieve the goal of fair payment for use of the grid with less risk and should be considered.

In closing, our sincere thanks for the opportunity to participate in this Task Force and help the Commonwealth achieve its energy goals.

<u>Solar Energy Business Association of New England (SEBANE), William Stillinger</u>

I am the representative for SEBANE, the Solar Energy Business Association of New England. This statement reflects the positions of the membership of SEBANE, a trade association whose members comprise both small and large-scale solar installers, project developers, equipment suppliers, consultants, and other related professionals in the solar industry. SEBANE's mission is straightforward: to promote the use of solar energy and the development of the solar energy industry in the region. Our primary policy focus has been in Massachusetts.

Our positions throughout the MA Net Metering and Solar Task Force (NMSTF) process have been guided by three principles:

- to ensure a stable and self-sustaining market for solar energy in the Commonwealth,
- to promote equal access to the benefits of solar energy for individuals, organizations, and communities, and
- to support development of utility rate structures whereby all customers pay equitably for their use of the electric distribution system.

The Net Metering and Solar Task Force

While some general issues have found consensus agreement in arriving at the Task Force's recommendations, in many instances the parties could do no better than to "agree to disagree" over several key issues.

1. Chief among the unresolved issues is actively dealing with the reality of having hit the caps (the artificially-imposed limits on solar capacity installations) in a large portion of the state; bringing to a halt medium and large project solar development in over 170 Massachusetts towns. It will be difficult to restore the economic momentum lost (including job losses) if the caps are not lifted quickly by the

legislature. The opportunity for Massachusetts to leverage the current 30 percent federal income tax credit (scheduled to expire at the end of 2016) will also be lost. And the achievement of the Commonwealth's goals for solar development and greenhouse gas reductions will be put further out of reach. Important classes of solar project hosts such as low-income housing organizations, municipal and community shared solar plans, use of landfill and brownfield space for clean energy are put on hold. **The caps must be raised by legislation enacted this year** in order allow the solar industry to transition to a long-term net metering and solar incentive policy that captures the interests of all stakeholders.

2. Legislation enacted this year should authorize an effort to be led by the DOER and the DPU to undertake an open and comprehensive solar benefit/cost study, so that policy makers are informed as they balance the often competing interests of the many stakeholders (including ratepayers who do not participate in solar programs, those who do, the utilities, society in general). With the holistic results of such a study in hand, one can see and evaluate the directions and degrees of cross-subsidies that may exist under the framework of net metering. This study procedure is described more fully below.

3. Net energy metering is of vital practical importance to the successful operation of solar and other distributed generating resources. The comprehensive benefit/cost study will thus be the basis for determining fair compensation for the various stakeholders, putting to rest unsubstantiated claims that solar development is doing economic harm, and properly dealing with any economic imbalances that may be found and substantiated.

4. The other solar incentive mechanism of importance that the Task Force could not agree to was the appropriate incentive mechanism to replace the current SREC system. The apparent choices were a periodic competitive procurement program, or an adjustable declining block mechanism. SEBANE strongly supports adopting the adjustable declining block mechanism, for reasons that are listed in the Task Force Recommendations Report.

5. At the outset SEBANE believed the Task Force's activities were to be focused on improving future solar policy, and that all the effort and investment that built the hundreds of MWs of existing solar facilities in the state would generally not be materially affected by changes to the policy. Surprisingly and sadly, the Task Force could not reach agreement on this important treatment of existing solar project investments. Tampering with the terms of existing project arrangements signals developers that they face increased future financial uncertainty, needlessly raising project costs.

The Analysis Performed So Far

The consultants' work has been extensive, complex, and far-reaching. In our opinion, after all of it no clear policy path with regard to solar incentives emerges from their analysis. This is not meant to denigrate the effort; only to say that the consultants' data can now best be used to provide a basis for further study of the differing perspectives that need to be balanced in setting long-term solar policy. Even the data that the utilities provided on their costs in administering solar programs might be useful in a future holistic analysis. But the data-gathering and work that was undertaken faced such time pressures that the consultants could not allow for a full variety of stakeholders to participate in the gathering of study assumptions and discussion of results. Task Force members themselves did not have enough to absorb the consultants' work.

Further Work to be Done

Presumably the legislature now has many of the major issues to be resolved laid out in (if not resolved by) the Task Force's report, so that they can prescribe and authorize the path forward. SEBANE believes parallel regulatory activities need to be initiated while the legislature sets the parameters of the next solar policy. In order to be widely accepted, solar electricity policy must proceed from a thorough and open benefit/cost analysis of solar energy as a distributed generation resource, interconnected and integrated with the grid. This evaluation (led by the DOER and the DPU) must be conducted in a transparent, open environment (all stakeholders engaged), so that it is consistently performed from multiple perspectives. Further, the analysis needs to be more than studying a snapshot in time. For proper comparison purposes the attributes should be evaluated over a consistent long-term (e.g. 20 years) net present value horizon, capturing most of the useful life of solar and other distributed generation facilities) to get all the disparate costs and benefits on a comparable footing. Regulators and legislators will then have the information they need to begin making informed and thoughtful policy decisions. Only by taking this whole systems view can policy makers balance the interests of society overall, ratepayers, the electric distribution companies, solar project owners, etc. in shaping our future direction.

A Final Word

It has been an honor to participate in the work of the Task Force. Its establishment last summer by the legislature was a major step toward opening up the public dialogue around solar policy in the state. In addition to our own constituents, SEBANE and other Task Force members have been mindful to work with and include an even broader solar community in the deliberations of the Task Force. If nothing more, this openness can be counted as a positive accomplishment. Now we look forward to working with the legislature and the DPU and DOER to enable solar energy to continue to efficiently bring its economic, social, and environment benefits to the Commonwealth.

Solar Energy Industries Association, Fred Zalcman

While the report of the Net Metering Task Force (NMTF) reveals many areas where stakeholders continue to express a diversity of perspectives, one conclusion stands out for the robust consensus it has drawn: Massachusetts wants solar. From the legislature to its constituents, from utilities to communities to businesses, we find only unanimity in the belief that Massachusetts can and should continue to ensure that solar is a growing part of our energy mix. Indeed, this broad position is the one that the NMTF chose as the very first principle in its report. The question is not if, but how.

There are two distinct policies under consideration: net metering, or the way that solar electricity is compensated for the benefits it provides to the grid; and SRECs, or the mechanism for delivering the additional incentives needed to make solar projects viable. Together, these policies are delivering benefits to the Commonwealth that far exceed the total costs to consumers, as shown by the NMTF consultants' report.[11] Based on numerous studies conducted by utility commissions across the country, SEIA's position is that net metering is fair compensation for the benefits it provides to the grid, and should not be altered. However, SEIA recognizes that reviewing net metering and incentive programs is a prudent and necessary action with the maturation of the solar industry in the Commonwealth. Implementation of the consensus of the NMTF – that solar should continue in Massachusetts, and that we should capitalize on the foundation and momentum we have built – depends on the thoughtful and careful management of any transition.

In order for the NMTF to be true to its most fundamental position, near-term action to address the net metering cap constraint is urgently needed. That said, SEIA fervently supports a transition to a sustainable net metering and solar incentive program and believes that a formulation that is in the long-term interests of all stakeholders is within sight.

SEIA believes that the best path forward is legislation this year that does three things:

1) Provides net metering cap relief for the period of time required to review and make any necessary and appropriate adjustments to ensure proper compensation to solar electricity;

[11] Consultant's 4/27/15 presentation of Task 3 results, Slide 20, available for download at < http://www.mass.gov/eea/docs/doer/renewables/analysis-of-costs-and-benefits-final-results-4-27-15.pdf>

2) Directs the DOER and DPU to conduct a transparent and comprehensive solar benefit-cost study to definitively determine the benefits or costs to ratepayers occurring under current rate designs and with respect to the major categories of solar development; and

3) Instructs the DOER to transition the solar incentive program from the SREC model to a more efficient incentive delivery mechanism.

With regard to Point #1, the consequences of a failure to provide near-term relief from the net metering caps are profound:

- Critical market segments that depend on the bill crediting mechanism enabled by net metering, such as community shared solar, low-income housing, landfill and brownfield development, local government projects, and customers who cannot install solar on their own property are no longer able to participate in the market;
- The window of opportunity for Massachusetts to leverage the 30% federal Investment Tax Credit (ITC) will close, resulting in the loss of a major outside revenue source in support of the Commonwealth's solar goals;
- The net metering cap constraint will shrink the Massachusetts solar economy as each of the utility and sector caps is hit in succession;
- The composition of projects will change significantly resulting in a loss of Massachusetts' rich diversity of project activity across market segments, customer classes, and system sizes; and
- Achievement of the Commonwealth's solar goals – both in terms of MWs and self-sustainability – will be delayed, and the total cost to achieve those goals will rise.

Already, members of the legislature are hearing from local officials, businesses, and residents who want to participate in solar projects in National Grid service territory, but that these projects cannot advance without net metering cap relief. Some members of the NMTF argue that "Maintaining the current caps will not impede solar development." Residents and local governments in the 171 cities and towns in the National Grid service territory would challenge that claim. The current net metering caps *are* impeding solar development, today. There are already hundreds of millions of dollars and thousands of construction jobs at risk. Supporting solar means addressing that constraint quickly.

Point #2 is a critical first step to determine if any potential adjustment to the way that solar is compensated through net metering is necessary. At its core, the claim some stakeholders make that net metering is unfair or unsustainable is rooted in a belief about the relative costs and benefits of distributed solar generation. It seems prudent that any change to the existing net metering framework – the framework, again, that has delivered significant, positive, and popular results – would only be made on the basis of a formal benefit-cost analysis that includes robust participation from multiple stakeholder perspectives, with a process for developing a record on how to properly value distributed solar generation, in a forum that recognizes and protects the interests of all parties.

The NMTF consultant report affirms that the Massachusetts' solar program has yielded benefits far exceeding the costs, and will continue to do so by a wide margin under most plausible future frameworks. However, it is important to highlight that the NMTF consultant report does not determine the relative costs and benefits of the current NEM policies in isolation but rather gives a general sense of the magnitude of costs and benefits of NEM and incentive policies combined. The NMTF consultant process is also not a sufficient substitute for the rigor required as the basis for making fundamental rate design reforms. As the NMTF report acknowledges, the process provided only limited opportunity to understand and provide feedback on the methodology and assumptions underlying the cost and benefit categories; in short, there was wholly insufficient opportunity for engagement by technical experts on key modeling and methodology assumptions that is the hallmark of the ratemaking process. Some stakeholders contend that net metering should be changed because it involves a cross-subsidy. Any such claim must be subject to a full and fair benefit-cost calculation to test that premise, such as that used in several other jurisdictions as a step towards making compensatory policy. SEIA recognizes the need to avoid the repetitive cycle of serial net metering cap increases and point #2 above proposes a path in that direction.

On point #3, SEIA recognizes consensus among NMTF members that the SREC program, while highly successful in stimulating the first phase of the Massachusetts solar market, can be – and ought to be – improved. Significant ratepayer savings can be captured by transitioning to an incentive delivery model that is more efficient – and therefore lower-cost – than the SREC program. SEIA believes that the legislature can instruct DOER to initiate this transition immediately and complete it on a faster timeline than any transition in the net metering program. Here, as with the net metering policy, we highlight that any program change should occur only after due notice to the industry and its customers.

Finally, it is critical that any change to the net metering or incentive framework apply prospectively, and not to projects in service, under construction, or into which significant development resources have been invested. As long as electricity is a regulated industry, investors will assess political and regulatory risk when making decisions about how much capital to invest, and at what price. To maintain the Commonwealth's ability to attract capital, existing investments must be held harmless in any transition.

In closing, I want to thank you, on behalf of my company, the Association, and personally, for the opportunity to serve on the NMTF. I'll return to the point with which I opened: Massachusetts wants solar, and there is no disagreement about that. We respectfully suggest that the task before the legislature now is to make both near-term and longer-term policy that shepherds the hard-won momentum in the local solar industry, along with the jobs, economic growth, and pride that it has stimulated. We look forward to continuing to work with the DPU, the DOER, legislators, members of the NMTF and other stakeholders on that process.

Consultant Task Reports

Note: The following sections are the work of the consulting team hired to perform analysis intended to inform the Task Force. While Task Force Members had input into the work performed, the resulting reports do not reflect the views of the Task Force Members and were not necessarily endorsed or incorporated by the Task Force into its recommendations.

Task 0. Task Force and Stakeholder Focus Groups

In order to better understand the perspectives of Task Force members and other stakeholders, the consulting team organized five 1.5 hours phone-based focus group sessions. Focus groups sessions included Task Force members representing similar constituencies. These sessions were conducted for the following Task Force groupings:

- Utilities;
- Utility customers and customer advocates;
- Solar industry representatives; and,
- Legislators.

A fifth focus group was conducted for non-Task Force stakeholders.

Themes explored during these focus groups included: perspectives on the current solar market model, perspectives on the current net metering approach, long-term goals for the Massachusetts solar market, perspectives on other solar incentive models, and perspectives on the future use of net metering and minimum bill provisions. Participants were provided with the opportunity to provide written comments along with their focus group session comments.

Transcripts of these discussions are provided in Appendix A of this report. During the sessions, individual Task Force members and other focus group participants highlighted a number of goals and key themes. Some of these are provided in the table below. Critically, these goals and themes were not unanimously expressed by all focus group participants and represent a cross section of Task Force opinions and priorities.

Focus Group Goals and Themes	
Ensure policy transparency and minimize complexity	Ensure fairness to those who have made past commitments
Minimize market disruption	Support steady industry growth
Minimize ratepayer impact	Support market-based approaches
Support PV siting where most needed	Transition to sustainable market that does not require incentives
Encourage supplier diversity	Encourage low-cost financing
Encourage participant diversity	Prioritize competitive market structures
Ensure cost effectiveness	Protect low-income ratepayers
Maximize solar PV installation growth	Minimize cost-shifting between participants and non-participants

Massachusetts Net Metering and Solar Task Force

Task 1 - Solar Incentive Policy Summaries

PEREGRINE ENERGY GROUP

Sustainable Energy Advantage, LLC

MEISTER CONSULTANTS GROUP

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Contents

1 Executive Summary

The Massachusetts Net Metering Task Force is addressing many of the critical issues related to solar market development, including incentive programs and net metering structures, which are currently being discussed in a number of other. A wide range of incentive types have been developed to promote solar market growth, with no U.S. states having identical solar policies. The Task Force has an opportunity to learn key lessons from the development and implementation of solar incentive programs in other states. Literature reviews were conducted to develop policy summaries that discuss the critical elements of a range of incentive mechanisms, from declining block programs to long-term contract solicitations and utility ownership programs. Policies reviewed under this task include:

- The California Renewable Market Adjusting Tariff (Re-MAT), Renewable Auction Mechanism (RAM) and declining block programs;
- The New York declining block programs;
- The Rhode Island Renewable Energy Growth program;
- The Delaware Solar Renewable Energy Credit (SREC) Solicitation program;
- The Connecticut Zero Emissions Renewable Energy Credit (ZREC) program;
- Utility financing, ownership, and long-term contracting programs in New Jersey;
- The Vermont Sustainably Priced Energy for Economic Development (SPEED) long-term contracting program; and
- Value of Solar Tariffs.

The policy choices made to develop each of these unique programs represent efforts by policymakers to balance sometimes-conflicting goals of solar market development scale and speed with ratepayer cost impacts. Summaries have been developed that examine critical policy elements, such as program structure, incentive-setting mechanisms, market size, long-term market goals, complimentary incentives and programs, resulting market characteristics, and other key elements.

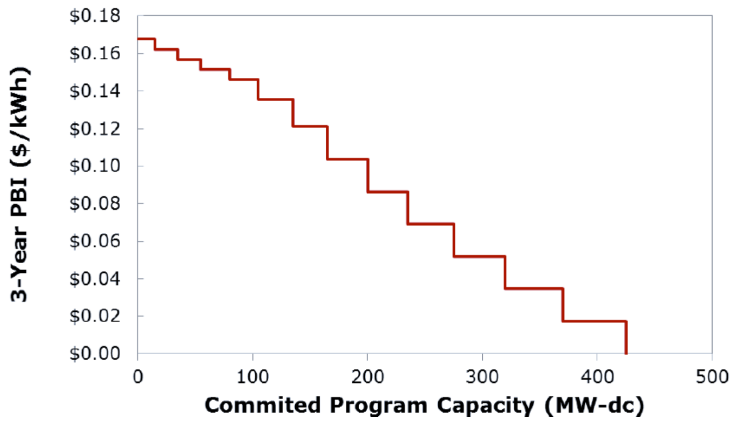
1.1 Policy Types and Key Findings

Policies examined in this report section fall into five broad incentive mechanism types: declining block incentives (DBIs), adjusting block incentives (ABIs), competitive solicitations, value of solar tariffs, and other incentive price setting mechanisms. Descriptions of each of these policies are provided below along with key considerations related to each incentive mechanism.

1.1.1 Declining Block Incentives

Declining block incentive programs have been implemented in both California and New York. This incentive mechanism type establishes a fixed, volume-based incentive schedule whereby incentives are provided at higher levels during the early phases of the program and lower levels in later phases. Once a block of incentives has been fully reserved, the program transitions to a lower incentive tier. This process continues until the total program volume has been reserved and the incentive level has been reduced to zero. Figure 1 illustrates this mechanism and shows the incentive block structure for one New York region.

Figure 1. Proposed Large MW Block Program Incentives for the ConEdison Territory (NYSERDA, 2014)



Block #	PBI ($/W)	Block Volume (MW-dc)
1	$0.63	15
2	$0.61	20
3	$0.59	20
4	$0.57	25
5	$0.55	25
6	$0.51	30
7	$0.46	30
8	$0.39	35
9	$0.33	35
10	$0.26	40
11	$0.20	45
12	$0.13	50
13	$0.07	55

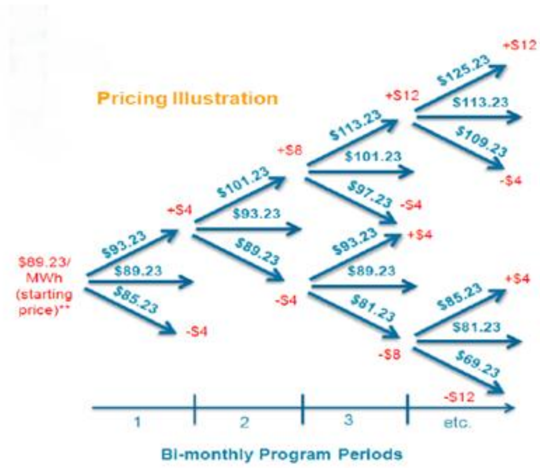
These programs have a predefined fixed budget and also result in a known quantity of solar being developed in advance of the start of the program. A fundamental component of DBIs is that they do not have a defined program timeline, meaning that the rate of solar PV installations under a DBI program will be unknown to policy makers. Declining block incentives are an open-access incentive type, meaning that incentives are distributed on a first-come, first-served basis. They can also be designed to either provide upfront rebates or performance based incentives (PBIs), which pay generators based on the power they produce over time.

The limited number of jurisdictions that have implemented DBIs have achieved market transitions that created self-sustaining solar markets which no longer rely on state-based incentives. These programs also have the advantage of providing market participants with incentive price transparency and can be designed to provide real-time information to market participants about incentive levels and application volumes. Despite these advantages, these programs have, to date, relied on predefined incentive reduction schedules, meaning they may not have the potential to adequately adjust to outside market impacts that could impact solar market growth such as unexpected increases in installed costs or changes to federal incentives. DBIs also have the potential to lead to uneven solar market activity if incentive levels decline more quickly than solar installation costs, making new installations unattractive to potential project owners.

1.1.2 Market Volume Adjustment Mechanisms (CA Re-MAT)

California has implemented a unique solar policy mechanism under its Renewable Market Adjusting Tariff (Re-MAT) program. This program provides solar incentives for a fixed volume of solar capacity through regular bi-monthly incentive offerings. Incentive levels adjust, up or down, in subsequent offerings based on the volume of incentive reserved during the previous incentive period. If the previous period's offering was significantly over-subscribed, incentives in the next offering are lowered. If the previous offering was significantly under-subscribed, the incentive level is raised. Figure 2 below shows this mechanism as implemented in one of the California utility territories.

Figure 2. Re-MAT Adjustment Mechanism



This program type provides an open-access, first-come, first served incentive offering. Because the programs have a fixed volume of capacity that is offered on a fixed schedule, policy makers can define the rate of solar market development as part of the program's design. This incentive type has the advantage of being responsive to outside market influences such as changes to federal tax incentives, making it potentially better able to support solar market stability. Like the DBI programs discussed above, this market mechanism provides near-term incentive price transparency for market participants, but unlike the declining block programs, market volume adjustment mechanisms are not designed to explicitly transition the solar market away from state-based solar incentives. Experience with this incentive model has been limited to date as it has only been implemented by three California utilities.

1.1.3 Competitive Solicitations (RI, VT, CT, CA, DE, NJ)

Competitive solicitations have been used by a number of jurisdictions to award solar PV incentives. Competitive solicitation programs in Rhode Island, Vermont, Connecticut, California, Delaware and New Jersey are profiled in this report. Under this program mode, a competitive process such as a solicitation or auction is used to award incentives, typically using a price-based selection criteria. Regular solicitations are conducted on a pre-determined schedule to create market activity over time. By relying on a competitive process, these incentive mechanisms award incentives to the lowest-cost projects within a market, potentially leading to lower overall policy costs relative to other incentive program mechanisms. These programs are not open access, requiring project developers to win an incentive allocation through a competitive process in advance of developing a project. Market activity for this program type will be defined by the volume and frequency of solicitations, providing policymakers with flexibility to define market activity.

Competitive solicitations have typically been used to provide solar incentives for larger-scale PV systems, as the time and expense of developing pricing proposals for smaller PV systems has been perceived by policy makers as a potential deterrent to residential market activity. These incentive program types may also result in high contract failure rates if programs are not carefully designed to prevent project proponents from submitting low-cost speculative bids. Additionally, infrequent or a limited volume solicitations may result in a small number of project developers receiving incentive awards, potentially reducing market competition over time.

1.1.4 Other Forms of Standard Offer Performance-Based Incentives

In addition to the incentive price-setting mechanisms discussed above, states have also used both administratively-set and competitively-derived mechanisms to determine PV incentive rates. Administratively-set pricing involves conducting cost-based modeling along with a public stakeholder process to determine an incentive level. This mechanism is currently being used as part of the Rhode Island Renewable Energy Growth program and was formerly used in the Vermont SPEED program. This price setting strategy allows policy makers target particular policy goals such as quickly growing the market or rewarding only the lowest cost solar projects. Calibrating pricing to meet these goals may be challenging and pricing incentives incorrectly can lead to unintended market dynamics.

Competitively-derived pricing has been used in Connecticut to establish incentive levels for smaller systems. Under this program, small system incentive levels are set as a function of incentive prices awarded to larger projects in the state's competitive solicitation program. This methodology has the advantage of ensuring that incentive prices are indexed to current market prices. Establishing the appropriate price adder requires careful consideration, as setting the pricing either too high or too low may result in market growth that is either too rapid or too slow.

1.1.5 Value-of-Solar Tariffs (VOSTs)

Value-of-Solar Tariffs are a relatively new incentive type that is intended to eliminate cross-subsidies between participating and non-participating net metering customers. In a VOST, solar generators are provided a per kWh incentive based on the market value of their production. This value is developed through an administrative process and can include elements such as:

- The wholesale value of the generated power,
- The value of avoided transmission and distribution investments,
- Avoided environmental compliance costs, and
- Other societal benefits.

In theory, VOSTs, if properly set should be cost-neutral from the perspective of all utility customers. These rates, however may not be sufficient to support solar market development. To date, Minnesota and Austin, Texas are the first jurisdictions to establish VOST rates.

1.2 Solar Incentive Levels in Other States

Each of the above-listed program types uses different mechanism to incentivize solar market development. Given the unique nature of each state's solar market, including the cost of developing and installing a project, the risks associated with different incentive types, and the availability and value of ancillary incentives, directly comparing incentive levels between states can be challenging. Despite this, reviewing incentive pricing levels in other states may provide Task Force members with critical context that can be used to support the development of recommendations regarding future solar market incentives in Massachusetts. The following table lists current incentive levels for the programs examined in this report chapter. Where applicable, ranges have been provided to indicate incentive levels for programs that provide multiple incentive pricing tiers. Further information regarding the specifics of each incentive program is provided in the following section.

Table 1. Current Solar Incentive Levels in Profiled States

State	Incentive	Incentive Type	Incentive Range
California	California Solar Initiative	Declining Block Incentive, Upfront Rebate or Performance Based Incentive	$0.20 per Watt rebate or $0.03/kWh PBI (non-residential)
	Renewable Market Adjusting Tariff (Re-MAT)	Market Volume Adjustment Mechanism, Performance Based Incentive	$57.23 – 77.23 per MWh PBI (10-20 years)
	Renewable Auction Mechanism	Competitive Solicitation, Performance Based Incentive	N/A
New York	Megawatt Block Program	Declining Block Incentive, Upfront Rebate or Performance Based Incentive	$0.80-0.30 per watt rebate
Rhode Island	Renewable Energy Growth Program	Competitive Solicitation/Administratively Set Price, Performance Based Incentive	$0.1640-.04135 per kWh PBI (15-20 years)
Delaware	Delmarva Power SREC Solicitation Program	Competitive Solicitation	$34.36 - $300 per MWh PBI (7-years + 13 years at $35 per MWh)
Connecticut	ZREC Program	Competitive Solicitation/Competitively Derived Pricing	$60.48 – $81.59 per MWh PBI (15 years)
Vermont	SPEED Program	Competitive Solicitation	$0.1187 to $0.1420/3kWh PBI (25 years)

2 Solar Incentive Policies in Other States

The following sections provide profiles of solar incentive polices in other states. For each program reviewed, a brief description of the incentive structure is provided along with information about key interactions with other state polices and critical observations about state-level solar market dynamics.

2.1 California: California Solar Initiative Declining Block Program, Re-MAT Tariff and Renewable Auction Mechanism Program

2.1.1 Introduction

California's solar market is the largest in the United States and is supported by three major incentive policies for different system sizes. Larger solar projects between 3-20 MW can participate in the Renewable Auction Mechanism (RAM), which requires investor owned utilities to procure 1,229MW of renewables via biennial reverse auctions. Smaller solar projects have historically benefited from a capacity-based, upfront payment incentive or a performance-based incentive (PBI) through the California Solar Initiative (CSI). The value of these cash incentives is based on a declining block structure tied to the overall installed capacity in each of the state's utility territories. Finally, systems 3MW and smaller are eligible for the California Renewable Market Adjusting Tariff (Re-MAT), which provides a 10-20 year standard offer contract based on $/MWh rate set by an innovative solicitation volume adjustment mechanism. These three programs are the focus of this policy profile.

California has a renewable portfolio standard (RPS) which requires 33 percent of each investor owned utility's retail sales to come from renewable or alternative sources by 2020. There is currently no solar carve out to the RPS, however the programs discussed in this section serve to support utility RPS obligations. California has a regulated electricity market, which is managed primarily by the California Independent System Operator (ISO). The California ISO contracts with Load Serving Entities (LSEs), and operates a day-ahead and real-time market.

California has had incentive support for solar since 1998 and California's incentive policies have continued to evolve since their inception. In 2006, Senate Bill 1 established Go Solar California, which funded and established California's existing incentive programs and shifted the market towards performance-based incentives. Administered by the California Public Utilities Commission (CPUC), Go Solar California has a total of $2.8 billion to disperse from 2007 to 2016 and has a target of 3,000MW of installed capacity by 2016.

Similarly, California's net metering policy has also changed as the solar market has continued to grow. In 2008, California allowed limited virtual net metering--or the distribution of net metering credits to multiple off-site locations. In 2013, the CPUC decided to extend the existing net metering program until July 1, 2017 or until individual utility program caps are reached after which distributed generators will receive a new tariff. There is an ongoing discussion on new policies and rate design at the CPUC related to this and other solar market issues.

2.1.2 Policy Description

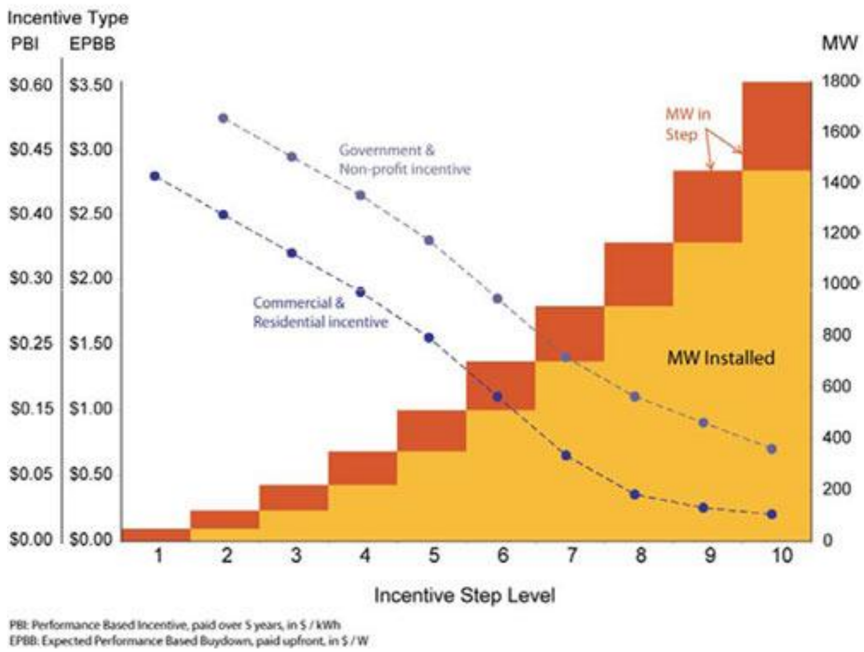
2.1.2.1 Declining Block Program

California developed two declining block incentive programs as part of the California Solar Initiative (CSI) to support smaller scale systems. The Expected Performance Based Buydown Program (EPBB) is an upfront incentive payment for

PV systems 30 kW and smaller. Projects 30 kW and larger are eligible for the Performance Based Incentive (PBI) program which provides $/kWh payments based on system output over five years. Smaller systems can choose to opt-in to the PBI program. The incentive amount a system receives is based on a declining 10-step schedule, which is determined by the installed MWs in the program for each utility territory. Non-profits, which are not able to take advantage of federal tax benefits, receive a separate, more generous incentive.

Figure 3 below shows the incentive rates and MW block sizes for the program (Go Solar California, 2015).

Figure 3. CSI Block and Price Diagram



As of January 2015, funds for the program have been nearly fully allocated, with both Southern California Edison (SCE) and Pacific Gas & Electric (PG&E) having completed their allocations and San Diego Gas & Electric (SDG&E) having only 5 MW of program capacity remaining. Since the expiration of the SCE and PG&E incentives, the PV market has continued to grow in those territories without access to the declining block programs. Even without state-funded incentives, California PV system owners still benefit from net metering and federal tax incentives. In particular, California electricity rates typically include inclining volumetric pricing, which can result in high net metering power values that can be highly beneficial for PV system economics.

2.1.2.2 Re-MAT Program

The Renewable Market Adjusting Tariff (Re-MAT) is a standard offer program that provides a PBI for distributed generators under 3MW. California's three largest IOUs (SCE, SDG&E and PG&E) conduct a solicitation every two months for long-term renewable energy contracts of 10, 15 or 20 years. Contracts are for both power and renewable energy attributes. Participating PV system owners are able to select contract lengths at the time of their application. The program solicits contracts from three renewable energy project types: as-available peaking, as-available non-peaking and baseload. These project categories correspond to renewable energy technologies such as solar, wind and biomass respectively. The program offers a fixed capacity in each solicitation and adjusts offer pricing for future solicitations based on whether the prior solicitation was over or under subscribed. The contract rate for each technology type adjusts upward or downward in increments of $4, $8, or $12 based on previous auction volumes. For instance, if a solicitation is significantly undersubscribed, the next solicitation price will increase by $4. If the next solicitation is again significantly undersubscribed, prices in the next round will increase by $8. After three rounds of significant undersubscription, the price will rise by $12. Figure 4 below illustrates the program's price setting methodology while Table 2 illustrates how price increases and decreases are determined based on solicitation volumes (Pacific Gas and Electric, 2013).

Figure 4- Re-MAT Adjustment Mechanism

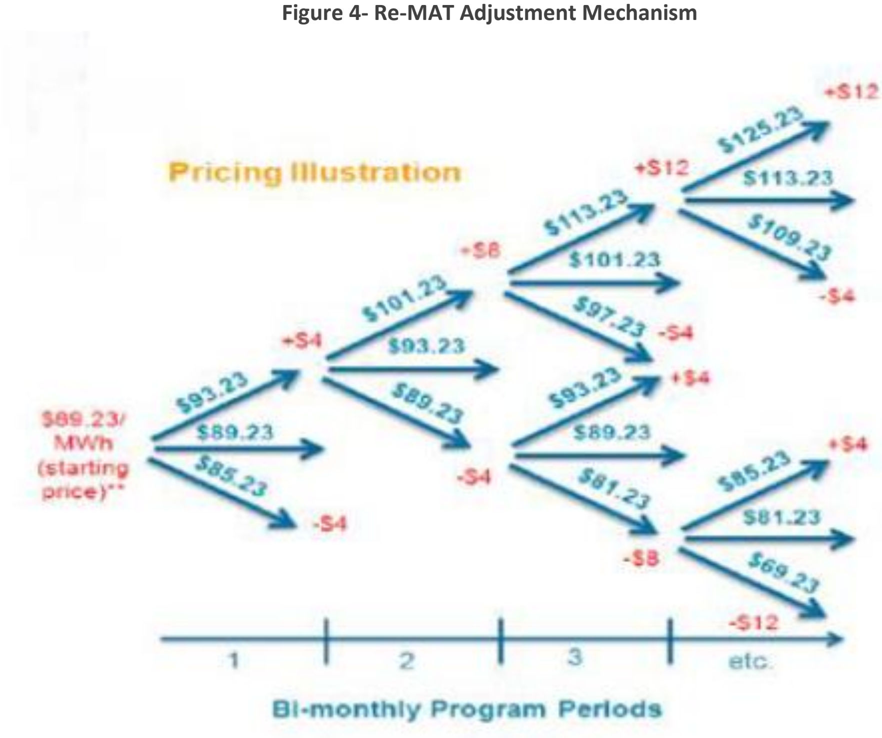


Table 2. Re-MAT Price Adjustment Mechanism

Subscription for Program Period MWs	Bi-monthly Period Price Adjustment
< 20% (0.0-0.9 MW)	Price Increase
20-99% (1.0-4.9 MW)	No adjustment
>=100% (5.0+ MW)	Price Decrease

The initial tariff level was based on the highest executed contract received by each investor owned utility in the renewable auction process (see discussion of RAM below). Table 3 below shows the historical pricing for the Re-MAT solicitation program for as-available peaking (i.e., solar PV) projects in each of the participating utility territories. Pricing does not include multipliers that are available for delivery of power during peak demand periods. PV systems with Re-MAT contracts can receive an additional 15 percent of their contracted power price for delivering power during critical periods (PG&E, 2015). The first solicitation round opened in October 2013 while the most recent round opened in January of 2015.

Table 3- Re-MAT Prices Rounds 1-8

Utility	Round 1	Round2	Round 3	Round 4	Round 5	Round 6	Round 7	Round 8
PG&E	$89.23	$85.23	$77.23	$65.23	$53.23	$57.23	$57.23	$57.23
Southern California Edison	$89.23	$85.23	$77.23	$77.23	$77.23	$81.23	$81.23	$77.23
San Diego Gas & Electric	$89.23	$89.23	$89.23	$89.23	N/A – segment fully subscribed	N/A – segment fully subscribed	N/A – segment fully subscribed	N/A – segment fully subscribed

As the table indicates, incentive prices have moved sharply down in the PG&E territory since the beginning of the program and have increased slightly during the last several solicitation rounds. In the SCE territory, the contract price initially declined, but has fluctuated near $80 per MWh during much of the program. SDG&E, which had a smaller overall solicitation volume, was fully subscribed after the fourth program round.

2.1.2.3 Renewable Auction Mechanism (RAM)

The CPUC required California's three largest IOUs to procure 1,229 MW of distributed generation to comply with RPS targets. Under the Renewable Auction Mechanism (RAM) program, five auctions occurred biennially between November 2011 and June 2014. A sixth auction was recently approved by California regulators and will include unused capacity from contracts awarded under previous solicitations as well as 75 MW of new capacity. Any generator qualified under California's RPS between 3 and 20 MW is eligible to bid into the auction. Eligible technologies include:

- Photovoltaics
- Solar thermal electric
- Wind
- Certain biomass resources
- Municipal solid waste conversion (Incineration ineligible)
- Geothermal electric
- Certain hydroelectric facilities
- Ocean wave, thermal and tidal energy
- Fuel cells using renewable fuels
- Landfill gas

Bids are selected by the IOUs based on project viability and bid price. Information on bid price is considered confidential and no data has been published on winning bid prices. Solar PV systems have been the majority of projects entering the RAM solicitations and more than 80 percent of the capacity awarded through the program has gone to solar PV systems (Hunt, 2014), (Public Utilities Commission of California, 2014), (San Diego Gas and Electric, 2014).

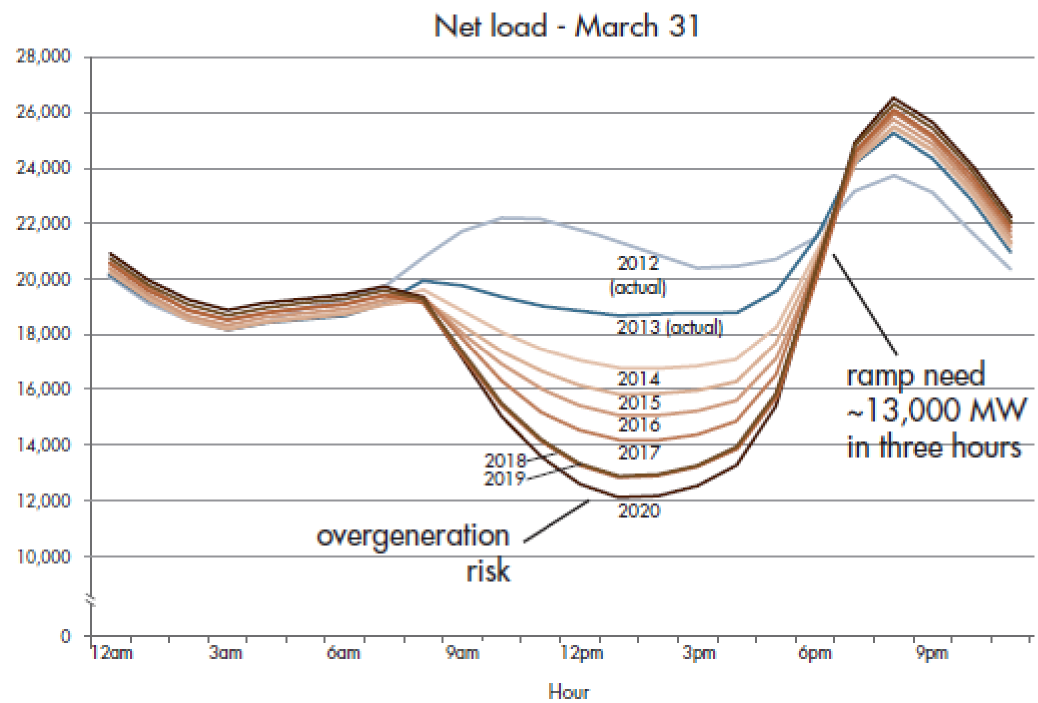
2.1.3 Key Interactions

As described above, California's solar programs are closely interconnected. The RAM, Re-MAT, and the California Solar Initiative are intended to support meeting state-wide RPS targets. The initial rate for the Re-MAT program was determined based on the results of the latest reverse auction held through the RAM process. Solar systems cannot benefit from both cash-based CSI rebates and the Re-MAT program. Additionally, many customer-sited systems participating in the CSI program benefit from net metering, which can be a substantial benefit given California's inclining block electricity rate structure. High net metering values have likely contributed significantly to the continued growth of the state's residential solar market since the end of the CSI program.

2.1.4 Impact and Observations:

California ranks first in the nation for installed PV capacity, and over half of the state's current installed capacity came online in 2013 (2,756MW of solar installations). Even though the declining block incentives have either been fully exhausted or have reached their enrollment caps, distributed solar continues to grow in California. Average installation costs have also continued to decline, falling 6 percent over the last year. (Solar Electric Industries Association, 2015). Existing installations and expected solar market growth in California has required the grid operator to consider future operating paradigms that are substantially different from historical demand patterns. Known in the industry as the "Duck Curve," the California ISO has developed a forecast under likely expected solar PV market penetrations in which the net power requirements on the grid drop considerably during hours of peak sunshine as utility customers generate more of their own power. Stakeholders in the state are actively engaged in exploring how flexible grid resources can be deployed to manage the energy supply and demand paradigms (California ISO, 2015).

Figure 5. The Cal-ISO Duck Curve Load Projections



As a large state with a substantial renewable energy RPS commitment, California has implemented a range of PV incentive programs that have created a diverse market. Creating incentive programs within distinct utility territories with different incentive pricing levels has allowed California's solar market to accommodate geographic differences in solar resources and local solar market conditions. As was seen in both the Re-MAT and CSI initiatives, the pricing and market development rates have been different in each utility territory allowing these state sub-markets to develop without a single region of the state receiving a disproportionate amount of solar incentives. This approach may be a viable option in Massachusetts where differences in real estate costs, PV installation costs and retail electricity prices could potentially create geographic imbalances in solar market development under a single incentive structure.

Both the Re-MAT and CSI declining block programs are innovative incentive setting mechanisms that overcome some of the challenges associated with typical standard offer and rebate-based programs. By establishing clear program criteria and adjusting incentive levels based on market conditions, these programs have limited ratepayer risk of over-subsidization. Additionally, the declining block incentive framework was structured to move the state's distributed solar market away from subsidies in a market-responsive fashion. Additionally, the fixed program budget and defined MW program target provides significant transparency into program costs. This mechanism has been adopted by New York as part of that state's latest incentive program iteration. One notable feature of the Re-MAT program its ability to increase incentive prices in response to changing market conditions. This policy feature is likely to make Re-MAT-like mechanisms more responsive to changes outside the control of state and utility program administrators such as changes to federal incentive policies or increases in global PV system component costs. Finally, the RAM program has shown that, at least in the California market, large scale solar PV systems can effectively compete against other renewable energy generators.

As with all programs that require centralized program managers to award incentives, some proportion of projects that are awarded incentives will not be constructed. This can result in programs not meeting overall market capacity goals and can frustrate developers with viable projects that were not awarded contracts. Both the Re-MAT and RAM programs have bid deposit mechanisms that are intended to prevent speculative bidding (PG&E, 2015). While these mechanisms are in place to limit potential contract failures, several of the California utilities routinely discount the expected production of renewable energy systems they have under contract but which have not yet been completed as part of their RPS obligation forecasts because of expected project failure rates.

The suite of incentive programs implemented in California over the past several years has resulted in steady market growth and the development of a sustainable PV industry in the state. The unique incentive rate setting mechanisms pioneered in California may be worth considering in the Massachusetts context as they provide market-responsive incentive pricing with standard offer, open-access incentives.

2.2 New York Megawatt Block Incentive Program

2.2.1 Introduction

In comparison to other East Coast states such as New Jersey and Massachusetts, New York has historically had a relatively small solar market. In 2012 Governor Cuomo launched the NY-SUN initiative, a $1 billion program to drive the development of 3 GW of solar PV by 2023. A continuation and expansion of previous state programs, the NY-SUN initiative fits within the framework of New York's RPS policy, which has a current goal of supplying 30 percent of the state's power from renewable sources by 2015. The state RPS is implemented through a two-tiered system with a Main Tier for utility-scale systems and a Customer-sited Tier (CST) for distributed installations. NYSERDA centrally procures the RPS Main Tier through regular solicitations for long-term contracts. NYSERDA implements several programs as part of the CST including programs for fuel cells, anaerobic digesters, small wind installations and solar PV. NYSERDA's solar PV programs, which have been in place since 2003, are now operated under the umbrella of the state-wide NY-SUN initiative. The state's current solar program offerings include a declining block incentive program called the Megawatt Block program. In early 2015, this program will expand to include larger-scale solar projects over 200 kW, which were previously supported by a competitive solicitation process. Funds for the program are paid for via RPS charges on ratepayers.

In 2010, the New York RPS target was expanded from 25 percent by 2013 to 30 percent by 2020. The Customer-sited Tier was also expanded from 2 percent to 8.44 percent. The New York Public Service Commission (PSC) recently raised the state net metering cap from 3 percent to 6 percent of 2005 peak demand after concerns that the existing cap would not enable the market to reach current goals. The PSC also commissioned a study on net metering impacts and a future value-based tariff.

New York has had retail electric competition since the 1990s, and the New York Independent System Operator (NYISO) serves as the transmission system operator for the state. The NYISO also operates capacity and ancillary service markets. The state has six investor owned electric distribution companies (EDCs) in addition to the Long Island Power Authority (LIPA), a public-power provider serving Long Island that has been recently rebranded as PSE&G Long Island. The territories of the investor owned EDCs have traditionally been under the jurisdiction of NYSERDA programs while the former LIPA territory has historically developed and implemented its own renewable energy policies. This has recently changed with NYSERDA now supporting renewable energy programs in the former LIPA territory.

2.2.2 Policy Description

New York's small-scale Megawatt Block program is an incentive program that provides upfront payments in the form of rebates calculated as a dollar per watt incentive. The program's incentive rate declines as MWs of capacity are enrolled in the program on a predetermined schedule. The current program provides incentives for PV systems up to 200kW. In recognition of the differing economics of PV systems across the state, NYSERDA has defined separate incentive levels and declining block schedules for the upstate region, ConEdison's territory and Long Island. Within each regional territory, a separate incentive with a distinct declining block schedule has been defined for residential and non-residential systems. The incentive is made available to installers approved by NY-SUN who then pass the savings on to consumers. PV systems in the program must serve less than 110 percent of on-site load. Non-residential systems receive a larger incentive for the first 50 kW of capacity and receive a smaller incentive for the remainder up to 200 kW. The step schedules for each utility territory are provided in Table 4 and Table 5 below along with the total MW expected from the program for each territory.[12] In each table, the current incentive block as of January 2015 is highlighted.

Table 4- Residential Program Tiers for Long Island, Con Edison and Upstate NY (NYSERDA, 2015)

	Long Island		ConEdison		Upstate	
BLOCK	MW	$/WATT	MW	$/WATT	MW	$/WATT
1	37	$0.50	14	$1.00	40	$1.00
2	15	$0.40	6	$0.90	15	$0.90
3	**20**	**$0.30**	**9**	**$0.80**	**19**	**$0.80**
4	50	$0.20	12	$0.70	22	$0.70
5			15	$0.60	24	$0.60
6			18	$0.50	31	$0.50
7			38	$0.40	70	$0.40
8			70	$0.30	75	$0.30
9			120	$0.20	148	$0.20
Total	**122**	**$40.5 MM**	**302**	**$113.2 MM**	**444**	**$194.1 MM**

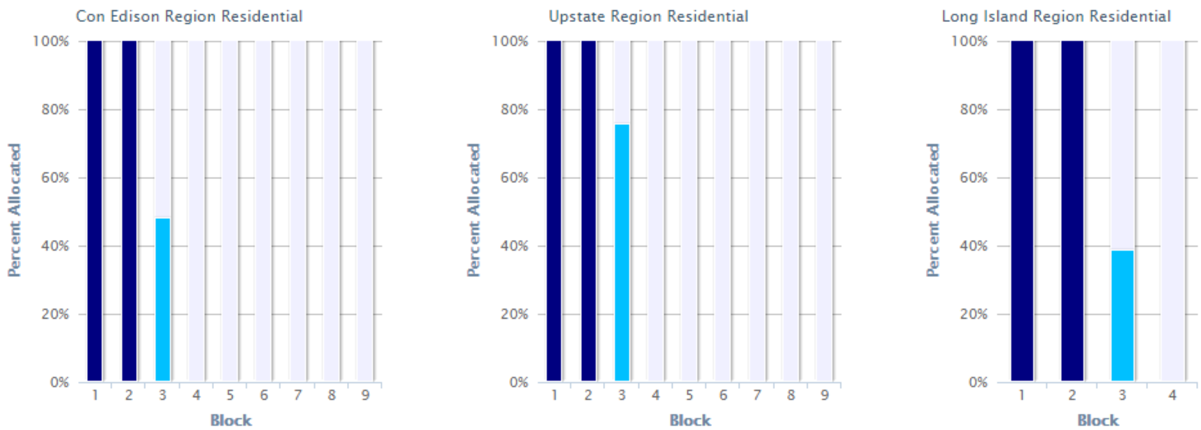
Table 5 - Non-residential Program Tiers for Long Island, Con Edison and Upstate NY (NYSERDA, 2015)

	Long Island			ConEdison			Upstate		
BLOCK	MW	0-50kW $/WATT	50-200kW $/WATT	MW	0-50kW $/WATT	50-200kW $/WATT	MW	0-50kW $/WATT	50-200kW $/WATT
1	7	$0.50	$0.50	6	$1.00	$0.60	35	$1.00	$0.60
2	**6**	**$0.45**	**$0.43**	**4**	**$0.90**	**$0.55**	8	$0.90	$0.55
3	7	$0.40	$0.36	6	$0.80	$0.50	10	$0.80	$0.50
4	9	$0.35	$0.30	8	$0.70	$0.45	**12**	**$0.70**	**$0.45**
5	15	$0.25	$0.23	10	$0.60	$0.40	18	$0.60	$0.40
6	14	$0.15	$0.15	15	$0.50	$0.35	23	$0.50	$0.35
7				35	$0.40	$0.30	28	$0.40	$0.30
8				45	$0.30	$0.25	77	$0.30	$0.25
9				73	$0.20	$0.20	95	$0.20	$0.20
10				101	$0.15	$0.15	145	$0.15	$0.15
Total	**58**			**303**			**451**		

NYSERDA maintains a website that provides real-time data on incentive step levels and provides data on the current volume of capacity that has been reserved. This allows solar stakeholders to have an up-to-date view of when incentive levels could decrease. Figure 6 below shows the online dashboard developed by NYSERDA for the program.

[12] Long Island has traditionally had a more robust solar market with lower installed costs. Additionally, electricity rates in Long Island are generally higher than those in many other parts of the state. The program incentive levels reflect these factors.

Figure 6. NYSERDA MW Block Program Dashboard (NYSERDA, 2015)



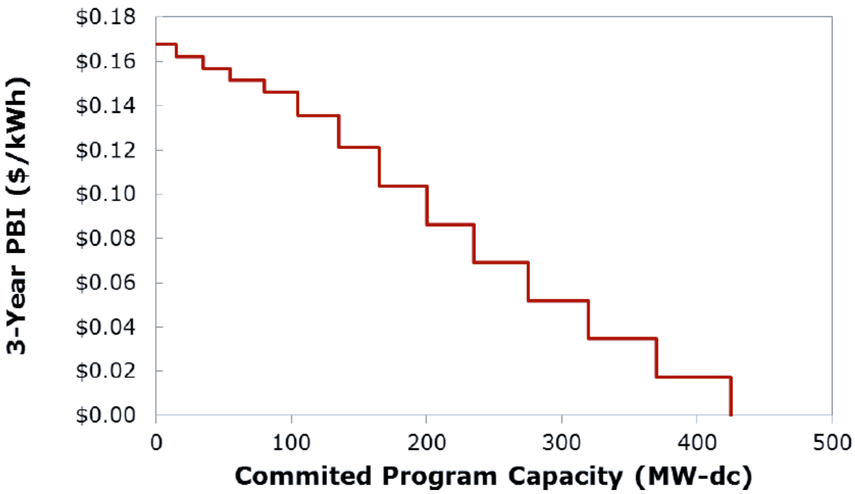
In addition to the small scale Megawatt Block Incentive Program, NYSERDA is in the process of developing a similar program for larger systems (customer-sited systems greater than 200kW). Like the program for smaller systems, this program will have a defined schedule of incentives that decline over time based on total volume installed. Unlike the program for smaller systems, the new program will provide incentives as a hybrid of a performance based incentive (PBI) and an upfront payment. The total maximum incentive will be based on the current block dollar per watt incentive level. This capacity-based incentive level will be used to calculate a maximum potential system incentive and associated $/kWh performance based incentive. System developers will be provided with 25 percent of the maximum incentive upon commercial operations of the system and then will be provided three annual payments that will be based on the systems actual production multiplied by 75% of the maximum system performance based incentive. Table 6 below illustrates a hypothetical 500kW system receiving a $0.63/kW block incentive. This table shows an ideal circumstance under which the PV system produces its estimated annual production. In the event that the system produces less than the expected production, the system owner's annual production-based compensation would be lower than the maximum available incentive.

Table 6. Illustrative Example of Incentive Calculation Under the Proposed NYSERDA Large System MW Block Program (NYSERDA, 2015)

Parameter	Value	Calculation
System Size	500kW	
Annual Production	586,920	(500 kW) X (13.4% Capacity Factor) X (8760 hours per year)
Maximum Incentive Amount	$315,000	(Total System Size) X ($0.63/kW Incentive)
Three year per kWh Incentive Amount	$0.179	(Maximum Incentive)/(Annual Production X 3 Years)
Upfront Payment at Commercial Operations	$78,750	25% X Maximum Incentive Amount = (.25) X ($315,000)
Year One Performance Payment	$78,750	75% X Three Year kWh Incentive X Annual Production = (0.75) X (0.179) X (58,6920)
Year Two Performance Payment	$78,750	(75%) X (Three Year kWh Incentive) X (Annual Production) = (0.75) X (0.179) X (58,6920)
Year Three Performance Payment	$78,750	(75%) X (Three Year kWh Incentive) X (Annual Production) = (0.75) X (0.179) X (58,6920)
Total Incentive	**$315,000**	Upfront Payment + Year One Payment + Year Two Payment + Year Three Payment

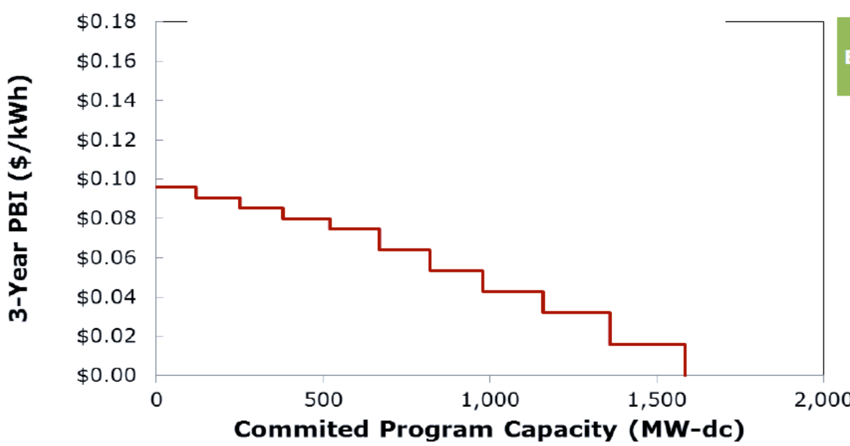
The current proposed large-scale Megawatt Block Incentive Program also provides 20 percent incentive value adders for locating PV systems in strategically critical locations as defined by the local electric distribution utility. This added incentive is intended to improve the economics of systems in geographic areas where solar PV has the greatest value to the grid. Figure 7 and Figure 8 show the current proposed incentive rates, block volumes and associated $/kWh incentives for the ConEdison territories and the remainder of the state. The remainder of the state incentive program has been geographically divided into a western region, with higher early incentives, and a non-western region.

Figure 7. Proposed Large MW Block Program Incentives for the ConEdison Territory (NYSERDA, 2014)



Block #	PBI ($/W)	Block Volume (MW-dc)
1	$0.63	15
2	$0.61	20
3	$0.59	20
4	$0.57	25
5	$0.55	25
6	$0.51	30
7	$0.46	30
8	$0.39	35
9	$0.33	35
10	$0.26	40
11	$0.20	45
12	$0.13	50
13	$0.07	55

Figure 8. Prosed Large MW Block Incentive Levels for non-ConEdison New York Regions (NYSERDA, 2014)



Block	PBI ($/W) ROS*	PBI ($/W) ROS-W*	Block Volume (MW-dc)
1	$0.36	$0.40	120
2	$0.34	$0.39	130
3	$0.32	$0.36	130
4	$0.30	$0.34	140
5	$0.28	$0.29	150
6	$0.24	$0.26	150
7	$0.20	$0.20	160
8	$0.16	$0.16	180
9	$0.12	$0.12	200
10	$0.06	$0.06	225

As currently proposed, the large system Megawatt Block Incentive Program would support 340 MW in the ConEdison territory at a total cost of $125 million. The estimated budget for the remainder of the state is $300 million and is expected to support 1,235 MW (NYSERDA, 2014).

2.2.3 Key Interactions

Megawatt Block Incentive Program participants assist with the achievement of the Customer-sited Tier of the New York RPS. Solar Renewable Energy Credits (SRECs) are not available in New York, therefore system owners receive these rebates in lieu of an SREC-based incentive. New York State also offers a 25 percent residential solar tax credit of up to $5,000, a sales tax exemption, and has loans available for solar systems through NYSERDA. Jurisdictions in New York also have the option to offer a property tax exemption for solar in an effort to reduce soft costs. Systems taking advantage of the Megawatt Block Incentive Program can also benefit from net metering in New York State. In New York, excess generation is credited at the full retail rate with annual excess generation credited at avoided cost rates. New York does allow remote net metering under which individual customers can allocate net metering credits to other accounts they are responsible for (NY PSC, 2011).

2.2.4 Impact and Observations

In designing the Megawatt Block Incentive Programs, NYSERDA sought to "provide certainty and transparency to the industry regarding incentive levels" and to provide incentives that account for differences in regional solar installed costs. The program was also designed with the intent of driving the state towards a self-sustaining market that was not reliant on state incentives (NYSERDA, 2014). The MW Block program is a relatively new incentive program with the small scale program launched in August 2014 and the large-scale program expected to be launched in early 2015. The early stages of the small-scale program have seen robust uptake in several regions. For instance the Long Island residential program tranche has already allocated 64 MW of the program's expected 122 MW, reducing the incentive level from $0.50 per watt to $0.30 per watt. Despite this early success, it is too early to evaluate how the market has responded to this program compared to previous NYSERDA offerings.

As a standard offer program with open access for approved installers, the NYSERDA Megawatt Block Incentive Program provides the benefits of an open-market program that does not require regularly scheduled solicitations. In theory, this market feature should reduce individual installation cost as project developers will not need to enter competitive solicitations that may require installers to develop multiple projects in order to win a single contract. This program feature will provide certainty and transparency to developers and should promote long-term industry growth. Counter to that benefit, the Megawatt Block Incentive Program has set a fixed incentive schedule, meaning that, in the event of changes from external market factors, such as major increases in global solar component costs or the expiration of federal tax benefits, the rigid structure of the Megawatt Block Incentive Program could create market contractions. In the event of such an occurrence, policymakers may feel significant pressure to revise incentive levels in order to prevent industry job losses. The pending reduction in the federal Investment Tax Credit could present a major challenge to declining block programs.

In designing the large-scale Megawatt Block Incentive Program, NYSERDA has established geographically distinct incentives for different state regions as well as bonus incentives for installations located in utility-identified regions where installations have the greatest value to the grid. This model may be of interest to Massachusetts policy makers as several stakeholders in the Massachusetts Net Metering Task Force process have suggested that location-based incentives that promote grid benefits be considered. As further details about the final design of the large-scale Megawatt Block Incentive Program become available, the effectiveness of this approach could be further evaluated. One additional potential consideration with this approach are potential equity concerns related to differentiated program incentives. Solar incentives are paid for by all electricity ratepayers yet only a sub-segment of ratepayers will have properties that allow them to take advantage of solar incentives. These incentive distributional effects may be further concentrated if added incentives are preferentially distributed to ratepayers in geographically defined areas.

The New York Megawatt Block Incentive Program has a fixed budget and predefined step-down schedule. This means that program administrators know the full cost of the incentive program at inception. This provides greater transparency compared to SREC market-based mechanisms in which annual compliance costs can be estimated, but not fully known in advance. While the overall cost of the program can be known in advance, with a fixed budget and schedule, but no fixed timeline, estimating annual program costs will depend on market response to incentive levels.

As a program with limited available data, project success and failure rates are unavailable at this time. That said, NYSERDA has proposed an enrollment mechanism for the large-scale program that is intended to prevent developers from reserving incentives and not moving forward with projects. This includes a reservation security deposit of up to 15 percent of the total estimated incentive or $25/kW, whichever is greater. Additionally, installers will have 18 months to install projects once incentives have been reserved (with the ability to apply for a 6 month extension if certain criteria are met).

The New York Megawatt Block Incentive Programs build off the model pioneered in California under the California Solar Initiative. In that state, the steadily declining incentives lead to a stable, unsubsidized residential solar market that has continued to grow over time. The New York declining block programs may repeat this success, however it remains to been seen whether this model will prove resilient in the likely event that major reductions occur to federal solar investment tax incentives. Regardless, the New York Megawatt Block Incentive Program has established a transparent incentive framework with standard offer incentives and a fixed program budget that could serve as a potential model for consideration by the Massachusetts Net Metering Task Force.

2.3 Rhode Island Renewable Energy Growth Program

2.3.1 Introduction

Rhode Island's Renewable Energy Growth (REG) Program offers 20-year utility tariffs[13] to qualifying solar, wind, anaerobic digestion and hydroelectric projects through a competitive process. The program is administered by the Office of Energy Resources (OER) and the Distributed Generation Board and is effectively an extension of the Distributed Generation Standard Contracts (DG SC) Pilot Program, which operated from 2011 to 2014. Maximum contract rates (referred to as "ceiling prices") are approved annually by the Public Utilities Commission (PUC). National Grid, the state's sole investor-owned utility, manages the competitive solicitations and enters long-term tariff agreements with successful bidders. The REG Program's objective is to successfully develop an incremental 160 MW of distributed generation in Rhode Island by 2019 (RI REF, 2015).

Rhode Island operates a competitive retail electric market, which was established through the Rhode Island Utility Restructuring Act of 1996. National Grid provides distribution service to the vast majority of the state's customer load. Retail customer access to competitive markets began in 1997, with National Grid assigned as the provider of Standard Offer service for customers electing not to switch their generation service.

Rhode Island offers a supportive policy environment for renewable energy, particularly for small on-site and distributed generation projects. The state has established a Renewable Energy Standard (RES), a long-term contracting standard for 90 MW of RES-eligible renewables as well as offshore wind supply, net metering, a Renewable Energy Fund which administers grants and loans, a DG Standard Contracts Program and the current REG Program. The RES was enabled in 2004 and originally required load-serving entities to supply 16 percent of retail sales with qualified *New* (14 percent) and *Existing* (2 percent) renewable energy resources[14]. Rhode Island's net metering program enables generators up to 5 MW to offset retail electric bills. Generators must be "reasonably designed" to provide up to 100 percent of a customer's annual electricity consumption (up to 125 percent for any individual billing cycle), so deliberately oversized projects are excluded. Net excess generation is credited at the utility's avoided cost. Multiple meters on a single, or adjacent, property may be aggregated, but virtual net metering is not offered – except to facilities owned by, or owned and operated on behalf of, municipalities or other public entities. There is an aggregate net metering capacity limit of 3 percent of peak load for Block Island Power Company and Pascoag Utility District, but this limit was removed for National Grid, which serves as distribution utility for the majority of load in the state. The Rhode Island Renewable Energy Fund[15] (REF) is a public benefits fund created by the 1996 restructuring legislation which offers grants and loans to a wide range of renewable projects. The REF currently supports four program areas: small solar, commercial development, feasibility studies, and early-stage commercialization. Small solar is supported primarily through a block grant program (currently offering grants of $1.15 per watt to a maximum of $10,000) (RE Growth Program Public Review Meeting, 2015).

The REG Program, which is just beginning in 2015, was developed in accordance with RIGL § 39-26.6-4 (a) (1) and the applicable provisions of RIGL § 39-26.2-4 and 39-26.2-5. It succeeds and replaces the Distributed Generation Standard Contracts Pilot Program, which had been in place since 2011 and offered up to 40 MW of 15-year power purchase agreements with National Grid through a similar competitive process. Both programs were developed in response to

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[13] A host-owned solar projects < 10 kW has the option to elect a 15-year tariff.

[14] In a 2014 determination of resource inadequacy, the PUC delayed the 2015 *new* RES target increase by one year and called for the overall *new* target to truncate at 12.5 percent rather than 14 percent.

[15] The REF was created under the Office of Energy Resources and is administered by the RI Commerce Corporation.

increasing pressure to attract the potential for renewable energy job and economic development to Rhode Island. The RES – while successful at meeting its goals to date – has largely resulted in procurement from out of state generators. Recognizing Rhode Island's limited land area and resource potential to support large-scale projects, policymakers turned their focus to distributed generation. The DG SC Program has successfully encouraged grid-connected projects between 50 kW and 3 MW. The REG program will expand the reach of this policy to include residential customers, streamline the contracting process by replacing Power Purchase Agreements (PPAs) with tariffs, and grow Rhode Island's distributed generation mandate to a total of 200 MW by 2019 – a substantial sum for a small state (RE Growth Program Public Review Meeting, 2015). It is designed to do so in a manner that is not additive to the net metering incentive, as discussed further below. As of January 2015, the DG SC program has concluded with 39.07 MW currently under contract, most of which is solar PV. Sixteen projects are operating and the remainder is under development. The REG Program commences in 2015, with a first-year contracting target of 25 MW (RI REF, 2015).

2.3.2 Policy Description

The REG Program offers a long-term, fixed price tariff between National Grid and qualifying renewable energy projects which is implemented as a performance-based incentive. The tariff approach replaces the use of contracts under the DG Standard Contract program. Host-owned solar projects less than 10kW may elect either a 15- or 20-year tariff. All other projects receive a 20-year tariff. Pricing is fixed and flat for the duration of the agreement. For solar projects up to 250 kW, fixed tariff pricing is approved by the PUC on an annual basis – there is no price bidding for these projects, and program MW are awarded on a first-come, first-served basis (H.7727 The Distributed Generation Growth Program, 2015).

All other projects must bid in response to one of up to three competitive solicitations offered annually. Awards are made based on price, assuming all other eligibility criteria are met. For successful projects, tariff pricing is "as-bid" and is paid by National Grid for all production. Once a contract is awarded, projects have 24 months (solar and wind) to achieve commercial operations.[16] A performance guarantee deposit is required to maintain each project's position in the program during this time. For projects less than 1 MW, a security of $15/REC (for total estimated REC production) must be received within 5 days after a project is awarded a place in the program through a Certificate of Eligibility. For projects of 1 MW or greater, a security of $25/REC is required. The exceptions to this rule are solar projects up to 250kW, for which no security deposit is required. National Grid is authorized to grant one 6-month extension at no cost for non-residential projects for unforeseen delays. A second 6-month extension (for a total of 12 months) may be granted if the project provides an additional security deposit of 50 percent of the original performance guarantee.

The DG SC Program was implemented using PPAs. The process of securing PUC approvals and administration also placed a burden on National Grid personnel. A cornerstone of the new REG Program is its implementation through utility tariffs. From the National Grid perspective, use of a tariff insulates the commitments from impacting the company's financial statements (an issue with PPAs) and places the transaction under PUC jurisdiction (power contracts falling under FERC jurisdiction). Policymakers, utilities and project developers hope that this will streamline the process while still satisfying financial institutions. Policymaker objectives with respect to project type have also evolved. The DG SC Program accepted only projects greater than or equal to 50 kW and interconnected on the utility's side of the meter. By comparison, the REG program allows residential participation, including a legislated target of 3 MW in the first program year. All projects under the REG program are required to have a generation (net) meter, which is interconnected on the utility's side of the host customer service meter.

[16] 36 months for anaerobic digesters or 48 months for hydroelectric.

The programmatic goal of 160 MW is divided into annual targets, and then further divided into segments by technology and project size. For example, the 2015 REG program will offer tariff to up to 25 MW of projects, allocated as follows:

Table 7. Allocation of 2015 Renewable Energy Growth Program MW

Technology & Eligible Class	kW Allocations
Small Solar I – Host Owned	3,000 kW* DC
Small Solar I – Third Party Owned/Financed	
Small Solar II	
Medium Solar	4,000 kW DC
Commercial Solar	5,500 kW DC
Large Solar	6,000 kW DC
Wind I	5,000 kW DC
Wind II	
Anaerobic Digestion I	1,500 kW DC
Anaerobic Digestion II	
Small Scale Hydropower I	
Small Scale Hydropower II	
Total	25,000 kW
***The REG statute requires a minimum of 3 MW be allocated to the small solar class during the 2015, 2016, 2017 and 2018 program years.*	

Annual program targets for the remaining program years are as follows: 50 MW in each of 2016 through 2018, and the greater of 15 or all of the remaining MW in 2019. In addition, any remaining (un-contracted or unsuccessful) MWs from the DG Standard Contracts Pilot Program will be added to the 2019 REG target (Tariff Advice Filing for Renewable Energy Growth Program and Solicitation and Enrollment Process Rules, 2014).

Competitively bid tariff rates are subject to a cap, which is referred to as a ceiling price. Ceiling prices are set administratively (by the PUC), based on recommendations developed by the OER and DG Board through a public research- and stakeholder comment-driven process. Independent research and stakeholder data submittals are combined in a consultant analysis which analyzes the levelized contract price required to enable projects to cover their costs and achieve a market-based, risk-adjusted rate of return. Ceiling prices are approved for each technology and size category. For example, the recommended 2015 REG ceiling prices are as follows:

Table 8. Recommended 2015 REG Ceiling Prices

Technology	Ceiling Prices (¢/kWh)
Small Solar I – Host Owned (15 Year Tariff)	41.35
Small Solar I – Host Owned (20 Year Tariff)	37.75
Small Solar I – Third Party Owned/Financed	32.95
Small Solar II	29.80
Medium Solar	24.40
Commercial Solar	20.95
Large Solar	16.70
Wind I	22.75
Wind II	22.35
Anaerobic Digestion I	20.60
Anaerobic Digestion II	20.60
Small Scale Hydropower I	21.35
Small Scale Hydropower II	21.10

Table 9 provides a summary of historic ceiling prices, established during the DG Standard Contracts Program.

Table 9. Historic Ceiling Prices*, DG Standard Contracts Program 2012-2014

Technology Class	2014		2013		2012	
	Size	¢/kWh	Size	¢/kWh	Size	¢/kWh
Small Solar			50-100 kW	29.95	10-150 kW	33.35
Medium Solar	50-200 kW	27.10	101-250 kW	28.80		
Commercial	201-500 kW	27.30	251-499 kW	28.40	151-500 kW	31.60
Large Solar	501-3000 kW	23.50	> 500 kW	24.95	501-1000 kW	28.95
Wind	1.0-1.5 MW	17.50	1.0-1.5 MW	14.80	N/A	13.35
Hydro	50 kW-1.0 MW	17.90	400-500kW	17.90		
Anaerobic Digestion	50 kW-1.0 MW	18.55	0.5-1.0 MW	18.55		

* *Including ITC (Solar, Wind) or PTC (Hydro, AD); without Bonus Depreciation*

The combination of ceiling prices and competitive solicitations has yielded declining contract prices over time. Figure 9 demonstrates the decline in DG Standard Contract Ceiling Prices between 2012 and 2014, and includes the recommended REG Ceiling Prices for 2015.

Figure 9. Ceiling Price Decline, 2012 - 2015

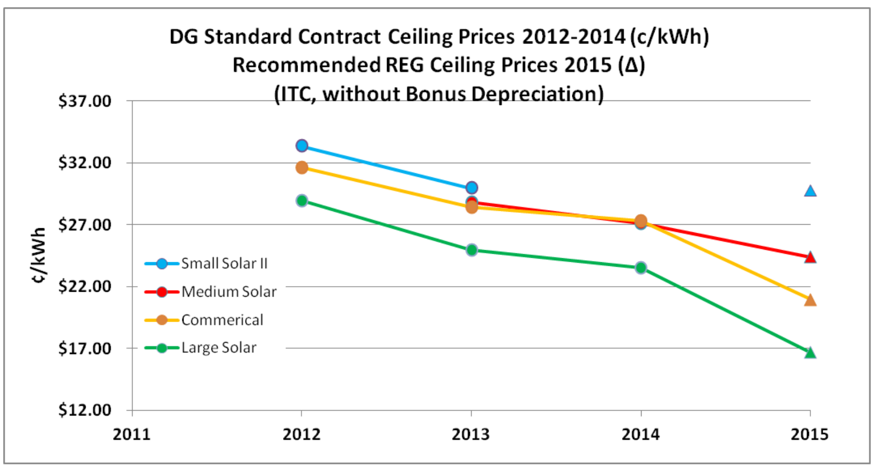
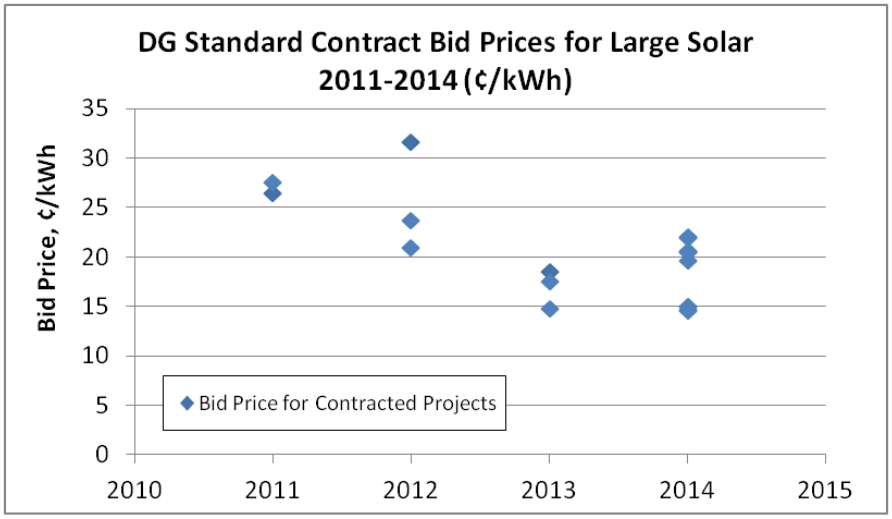


Figure 10 demonstrates the range, and overall decline, in the bid prices of large solar projects selected for DG Standard Contracts between 2011 and 2014. As can be seen, prices have at times been well below the ceiling prices, although in 2014 this trend leveled off (anecdotally, prices in 2013 were reportedly at unsustainable/unprofitable levels).

Figure 10: Bid Prices of Large Solar Projects Selected for Standard Contracts, 2011 - 2015



As demonstrated by the data in Table 8 and Table 9, and the trends in Figure 9 and Figure 10, the ceiling price construct provides policymakers with a mechanism to benchmark price caps to market conditions and make course corrections over time. Through this process, Rhode Island hopes to support its dual objectives of supporting renewable energy development at a just and reasonable cost to ratepayers.

2.3.3 Key Interactions

All projects participating in the REG Program (and the DG Standard Contracts Program before it) must be qualified as Rhode Island RES *New* resources. For all non-residential customers, both DG Standard Contracts and REG Tariffs convey all energy, capacity and renewable energy certificates (RECs) to National Grid. By statute, residential customers retain all energy and capacity for self supply, selling only RECs.[17] In all cases, National Grid owns all RECs, which it may apply towards its RES compliance obligation or liquidate into the regional market.

During the initial DG SC Pilot Program, project owners were compensated by National Grid through a PPA for all output. DG SC generators were not eligible to be net metering generators. For the REG Program, projects operating under the non-residential tariff may elect to be compensated either directly (e.g. by check) or through bill credits which resemble a form of net metering. Bill credits are provided for the lesser of the project's output or the customer's use during the billing period. Bill credits are calculated at the full value of the per kWh delivery and commodity charges applicable to their current service rate. This amount is then deducted from the full REG tariff (PBI[18]) rate, with the remaining balance (if any) paid by check. If the bill credit in a given month exceeds the PBI, the customer will receive the full amount of the bill credit (which will not exceed the total of the per kWh delivery service and standard offer charges). In other words, the customer benefits from the greater of the PBI and net metered value, but the PBI and net metering credit are not additive. Projects electing the bill credit approach must comply with all other requirements of the net metering program – including the limitation of project installed capacity to no more than 100% of the customer's three-year historic average load. All residential projects are compensated under the bill credit mechanism described above and must therefore comply with all net metering requirements. For both residential and non-residential projects, those eligible may revert to the net metering program at the conclusion of their REG tariff. Small solar projects must elect

[17] Energy and capacity are deemed to be consumed on-site, and are not available for sale to the utility.
[18] Performance-based incentive.

either the REG Program or the REF Grant Program. These are important attributes of the REG Program and unique interactions between a PBI and Net Metering Credit (RE Growth Program Public Review Meeting, 2015).

Finally, the DG SC and REG Programs also take into account the interaction between ceiling prices and federal renewable energy policy. During each year's ceiling price evaluation process, the OER and DG Board consider the federal incentives likely to be available during the following program year (for which ceiling prices are being set). When federal incentives are uncertain, the OER and DG Board may submit more than one set of ceiling prices to the PUC – reflecting, for example, pricing options with and without the Investment Tax Credit (ITC).

2.3.4 Impacts and Observations

The DG Standard Contracts Pilot Program achieved some success in attracting at least an initial burst of attention to the potential for solar development activity in Rhode Island. During the 2012 and 2013 program years, new access to utility long-term contracts, federal incentives, and robust ceiling prices spurred activity among solar developers. During this period, both smaller in-state developers and much larger regional and national developers began to establish project pipelines and submit bids to National Grid. For the larger solar categories, 2012 and 2013 solicitations were over-subscribed, and contract prices declined rapidly. Wind and anaerobic digesters have not followed this trend, receiving serious attention from only one developer each throughout the program.

The diversity of solar market participants was temporary. During 2014, market participation decreased significantly. This was likely due to a combination of factors, including: reduced margins driven by price competition (and based on the authors' anecdotal conversations with various market participants over the course of the last several years, potentially speculative bidding), the limited amount of program MWs, siting and permitting challenges, high or uncertain property taxes, and a greater volume of opportunities in other state markets in the region. Developers may be able to justify an unsustainable margin in order to complete an initial project and establish a market foothold, but - by definition - a viable business cannot be built in this manner. To this end, the bidding activity and price declines of 2012 and 2013 may have been (at least in part) symptoms of exuberance among less experienced developers. The degree of project attrition over time will help to determine the extent to which this may have been the case. The 2014 solicitations had less participation than in 2013 and were generally undersubscribed. National Grid observed that the allocations in 2013 along with the allowed ceiling prices drove high interest in limited class sizes in 2013. In 2014, there was a decline in several solar class ceiling prices while the amount allocated in some classes and flexibility was increased. The 2014 solicitations were ultimately less competitive than in prior years (a higher percentage of projects that applied were awarded contracts) while the price in some classes and overall still declined. By the end of 2014, the larger regional players appeared[19] to exit the market. Because the annual target MWs were allocated by technology and by size, the program as a whole fell short of its targets on numerous occasions when one or more categories was undersubscribed. This is a side-effect, and possibly a short-coming, of integrating specific inflexible diversity targets

During the first two program years (2011[20] and 2012), 16 projects totaling 15.12 MW executed Standard Contracts with National Grid. Since then, twelve (12) of these projects have become operational and four (4) projects totaling 2.15 MW (25 percent of projects and 14.21 percent of MWs) have terminated their contracts. As of the December 2014 program end date, the DG Standard Contracts Program includes 46 active contracts totaling 39.07 MW, which consist of 41 solar,

[19] Some market participants have speculated - although we cannot confirm this - that developers may have decided to wait for the REG program with its larger size, lower transaction costs, and hoped-for greater margins.

[20] The program initiated in 2011, which was a partial year – with one enrollment period offered in the fall.

1 anaerobic digester, and 4 wind projects. No contracts were awarded to small scale hydropower. Due to the challenges presented by renewable energy permitting, financing and construction, it is reasonable to expect additional attrition. It is too early to assess an attrition rate for the remainder of active projects. Again, any MW not constructed under the Standard Contracts program will be rolled into the final 2019 solicitation under the REG Program (Renewable Energy Growth Program, 2014).

Procurement structure also has an influence on the program. While common in many markets, periodic procurements tend to foster episodic bursts in market activity rather than foster a fluid market. It is challenging to realize permanent job growth in a market that limits the development of stable project pipelines. This may lead to frustration for project hosts and developers alike since the project development process requires ample lead time and sufficient certainty in increasing demand over time to justify continued investment. Rhode Island's small size, and the pilot nature of the DG Standard Contract program, preclude over-interpretation of the programs' impact on in-state jobs (the prospect for job growth in Rhode Island may be closely linked with the level of activity in its larger neighbors). Compared to the Connecticut ZREC program with its once per year procurements, the more frequent procurements in Rhode Island's programs provide for a steadier stream of activity in support of job creation.

Overall, the Rhode Island DG SC and REG programs hold the potential to offer considerable benefits to developers through long-term, fixed price contracts for energy, capacity and RECs with a creditworthy utility. This should provide the market and revenue certainty necessary to encourage continued market investment and attract financing at reasonable costs reflective of minimized revenue risk. In addition, the REG Program's future relationship to net metering is clearly spelled out in National Grid tariffs, and distributed generation will be supported in a manner that is well-matched to distributed loads. This approach is designed to avoid over-subsidization through separate net metering and solar incentive programs.

As described, however, the program faces some challenges. Like other competitive procurement programs, competition can be eroded at times by some degree of aggressive or speculative bidding, and the ensuing project attrition (Wiser, O'Connell, Bolinger, Grace, & Pletka, January, 2006). While Rhode Island's small market size is undeniably a factor, these dynamics create tension in a program designed to achieve a diversity of participants, technologies and project sizes. Due to its much larger size and the current robustness and diversity of participants, Massachusetts may be able to adopt aspects of the Rhode Island program that generate certainty and developer investment without impairing the state's ability to achieve its goals for a range of market segments.

2.4 Delaware SREC Solicitation Program

2.4.1 Introduction

Delaware first implemented a state-wide renewable portfolio standard in 2005. This legislation has been revised on several occasions. Under the current policy, 25 percent of the state's electricity must be sourced from renewable energy sources in the PJM region by 2026. Unlike most other RPS states which place their RPS obligation on load-serving entities, in Delaware this obligation is placed on the state's distribution providers (Delmarva, DEC, and DEMEC).[21] As part of the state's RPS program, distribution utilities are required to source a specific portion of their renewable obligation from in-state solar installations. Utilities can fulfill this obligation either through owning their own generation or by purchasing and retiring Solar Renewable Energy Credits (SRECs). Both DMWEC and DEC have pursued a strategy of fulfilling their solar RPS requirements through self-generation. Delmarva has taken a portfolio approach to meeting its annual SREC obligations. This includes procuring SRECs through various brokerages, purchases from individually negotiated long-term contracts as well as the implementation of the SREC Solicitation Program (Delmarva Power, 2014).[22] The SREC Solicitation Program is implemented in cooperation with the Delaware Sustainable Energy Utility (SEU), a state-sponsored entity charged with developing and implementing energy efficiency and renewable energy programs and policies in Delaware.

Delaware has a restructured electricity market and is part of the 13-state PJM regional transmission organization (RTO). Delmarva power is the state's only investor owned utility (IOU), serving roughly 60 percent of Delaware's load. The Delaware Electric Co-operative (DEC) provides distribution services in the state's two southern-most counties and accounts for about 20 percent of Delaware's total load. Additionally, the state has a nine municipal utilities which are served by the Delaware Municipal Electric Co-operative (DEMEC). The SREC Solicitation Program was originally approved by the Public Services Commission in 2011 and has held annual solicitations in 2012, 2013 and 2014. Originally launched as a pilot, the solicitation program has evolved over time, with each annual solicitation having different program parameters. The overall goals of the solicitation program are to provide long-term SREC contracts to system owners, ensuring incentive price certainty while also creating a competitive landscape to limit ratepayer costs and ensure only the most cost-effective solar PV systems receive incentives.

[21] Municipal electricity providers and rural co-operatives are given an option to opt-out of the RPS if they develop and implement comparable renewable energy programs.

2.4.2 Policy Description

The SREC Solicitation Program has undergone a series of changes with each annual iteration of the program. The program offers long-term contracts to PV system owners for SRECs. Contacts awarded under the solicitation program have typically had a step-down feature, with SREC prices for the first period of the contract (i.e. seven years in the most recent solicitation) awarded to system owners at the as-bid contract price and the second phase of the contract (i.e. years 8-20 in the latest program solicitation) at a pre-determined fixed rate. For the 2014 solicitation, this fixed rate was set at $35 per SREC. In the 2012 and 2013 solicitations, this price was $50 per SREC. Delmarva has not indicated a specific annual target for the percentage of its total SREC obligation it intends to procure through this program, although roughly 30 percent of its 2014 obligation was satisfied through SRECs procured through the program (Delmarva Power, 2014).[23]

Delmarva and its contracted program administrator[24] hold annual solicitations in which system owners bid an initial contract price for SRECs.[25] Contracts are awarded to lowest bidders first until the full volume of available credits is procured. In an effort to promote the growth of a diverse solar market that is accessible to a range of market participants, the program is divided into different solicitation tranches based on system size. The number of tranches and the relative volume of SRECs procured in each tranche has changed over the course of the annual solicitations. Additionally, the program includes tranches for both existing systems that do not currently have long-term SREC contacts, as well as new systems.[26] Table 10 shows the total number of annual SRECs procured in the 2014 solicitation (SRECDelaware, 2014).

Table 10. 2014 Delmarv Power SREC Solicitation Program Tranches

New Systems (systems with final interconnection approval after April 12th, 2013)		
Tier	**Nameplate Rating - (DC at STC)**	Annual SRECs in Tier
N-1	Less than or equal to 30 kW	3,800 Pool*
N-2	Greater than 30 kW but less than or equal to 200 kW	1,600
N-3	Greater than 200 kW but less than or equal to 2 MW	1,600
Existing Systems (systems with final interconnection approval before April 12, 2013)		
Tier	Nameplate Rating - (DC at STC)	SRECs in Tier
E-1	Less than or equal to 30 kW	3,800 Pool*
E-2	Greater than 30 kW but less than or equal to 2 MW	3,800 Pool*
* Systems in the N-1, E-1 and E-2 tiers compete for the same pool of SRECs		

For the 2014 solicitation, the two tiers for existing systems (E-1 and E-2) and the tier for smaller systems (N-1) each competed for the same pool of 3,800 annual SRECs.[27] In order to limit speculative bidding, bidders are required to provide a bid deposit of $100 per kW in order to enter the solicitation. Bid deposits are returned to solicitation entrants that are not awarded contracts or when winning bidders finish construction of their PV system. Additionally, the

[24] For the first two solicitations, the Delaware Sustainable Energy Utility (SEU) and SRECTrade jointly administrated the program. Since 2014, InClime has administered the program along with the SEU.

[25] Under the Delaware solar incentive model, system owners qualify for net metering as well as SREC-related incentives.

[26] New systems can include systems that have already reached commercial operations since the last auction or systems that are planned to begin operations within twelve months.

[27] In August 2014, the Delaware SEU launched an upfront payment program for smaller PV systems which was intended as an alternative to the SREC solicitation program.

program applies penalties to winning bidders if the delivered volume of SRECs is substantially below the SREC volume bid by the system owner in any given year.

Table 11 below shows the range of prices bid for winning bidders as part of the 2014 solicitation. As mentioned previously, winning bidders are granted a 20-year SREC contract for the first seven years at the price bid into the auction. The remaining years of the contract are at $35 per MWh. Of note, the rules of the Delaware SREC program provide multipliers for systems that use Delaware-manufactured materials and/or use Delaware sourced labor, meaning that the actual value per MWh of generation for winning bidders may up to 20 percent higher than the values shown below.[28]

Table 11. Winning Bid Pricing for the 2014 Delmarva SREC Solicitation

Tier	Low Bid	High Bid	Weighted Average Bid Price
N1, E1, E2 Pool	$0.00	$300.00	$53.44
N2 (New systems >30kW to <=200kW)	$34.46	$141.23	$88.84
N3 (New systems >200kW to <=2 MW)	$98.73	$98.73	$98.73

Prices in the three annual solicitations have generally declined over time. Table 12 and Table 13 below show weighted average winning bid prices for the 2013 and 2012 solicitations respectively. Tier sizes, contract lengths and other parameters have all changed over the course of the solicitations making direct year-over-year comparisons difficult. In the first solicitation year, smaller system sizes were awarded contracts at an administratively-set contract price with winning bidders selected through lottery. Administratively set prices are show in Table 13 for reference.

Table 12. 2013 Delmarva SREC Solicitation Prices

Tier	Weighted Avg. Bid Price
N1 (New systems <= 30kW)	$46.48
N2 (New systems >30kW to <=200kW)	$86.60
N3 (New systems >200kW to <=2 MW)	$51.13
E1 (Existing systems <= 30kW)	$34.59
E2 (Existing systems (>30kW to <= 2MW)	$39.29

Table 13. 2012 Delmarva SREC Solicitation Prices

Tier	Weighted Avg. Bid Price
Tier 1 (Administratively set, up to 50kW)	$260
Tier 2A (Administratively set, 50 to 250kW)	$240

[28] Systems using Delaware-sourced parts receive 1.1 SRECs per MWh of generation. Similarly, systems using Delaware labor receive 1.1 SRECs per MWh of generation. Systems qualifying as using both Delaware-sourced parts and Delaware labor generate 1.2 SRECs per MWh.

Tier 2B (Competitive, 250 to 500kW)	$131.13
Tier 3, (Competitive, 500 to 2,000kW)	$154.35

As the three tables show, bid prices generally declined between the 2012 and 2013 solicitations, however no obvious trend in pricing is evident between the 2013 and 2014 solicitations. This may be, in part due to the lowered later year SREC values provided to winning bidders in the 2014 solicitation.

2.4.3 Key Interactions:

Contracts awarded under the SREC Solicitation Program are one of several incentives available to Delaware PV system owners. As an alternative to the SREC Solicitation Program, the Delaware SEU recently launched an upfront payment program for smaller systems under which system owners agree to sign over all SRECs generated by their systems for a 20-year period. System owners taking part in this program cannot be awarded long-term SREC contracts under the SREC Solicitation Program.

In addition to benefitting from revenues from SREC sales, Delaware PV systems also take advantage of net metering. In the Delmarva territory, net metered systems have a 2 MW limit and qualify for full-retail rate compensation for power exported to the grid. Delaware net metering rules also allow for meter aggregation and community solar models (Delaware PSC, 2011). Table 14 below lists the average residential, commercial and industrial retail electricity rates for Delaware as of October 2014 (U.S. Energy Information Administration, 2015).

Table 14.Delmarva Power Retail Electricity Prices

Rate Type	Average Rates
Residential	14.72 cents/kWh
Commercial	10.32 cents/kWh
Industrial	7.68 cents/kWh

2.4.4 Impact and Observations

Compared to states with more aggressive solar RPS carve-outs, such as New Jersey, the Delaware renewable portfolio standard has established relatively modest near term solar energy targets. The RPS schedule requires incremental annual capacity addition in the 20 to 30 MW range each year between 2010 and 2025. These limited increasing incremental annual SREC targets, as well as Delmarva Power's existing bi-lateral SREC contracts[29] and a state-wide SREC oversupply, have limited total volumes procured under the SREC solicitation program over its first three years. In fact, the first year of the program saw the highest volume of SRECs procured, with 20-year contracts for 11,472 (estimated 8.6 MW) total SRECs/year awarded under the solicitation. The 2013 solicitation awarded long-contracts for 7,000 SRECs/year (approximately 5.2 MW) while the 2014 solicitation awarded contracts for 6,600 SRECs/year (approximately 5.0 MW). Given Delmarva's efforts to procure limited volumes of new SREC contracts every year in order to satisfy its expected obligations, and the state's relatively steady annual SREC RPS requirement, the Delaware solar market is unlikely to see major year-over-year growth in the coming years.

The SREC Solicitation program has been designed to promote market diversity. With multiple solicitation tiers for different system sizes, the program has ensured that a range of system types can participate in the program. This market diversity has increased the total number of systems installed in the state compared to a program that would support only larger systems, likely increasing total employment related to the program. Given the limited volume of SRECs

[29] Delmarva has existing bi-lateral SREC contacts with generators in the state that were signed before the creation of the SREC Solicitation Program.

procured in each annual solicitation and the even smaller number procured in each tier, market interest in some tiers for some solicitations has been limited to only a few proposed projects. The SREC Solicitation Program has driven market competition with SREC contract prices declining between the first and second solicitations. One potential concern for small solicitations is that limited participation can result in winning bidders receiving higher contact prices than would be available in a more competitive program.

A full ratepayer impact analysis is beyond the scope of this policy summary, and, given the portfolio approach taken by Delmarva, comparing the ratepayer costs related to the SREC Solicitation Program to other SRECs acquired in their compliance efforts is challenging. In its 2014 RPS compliance filing, Delmarva reported acquiring 37,214 SRECs in order to meet its RPS obligation. The reported weighted average price for these SRECs was $141.55. SRECs retired in 2014 procured during the 2012 pilot solicitation had an average reported price of $213.26 while SRECs procured during the 2013 solicitation had an average price of $45.17. SRECs procured through brokerage transactions by Delmarva for the 2014 compliance year had an average price of $62.46 suggesting that SRECs procured through the 2013 solicitation were below spot market prices during the compliance year while those from the 2012 solicitation were above spot market prices (Delmarva Power, 2014).

Total Delmarva costs related to all SRECs retired in 2014 were $5.6 million. Distributed across Delmarva's 2014 load, SREC compliance costs are less than 0.08 cents per kWh. Included in this compliance cost are $296,779 in administrative fees associated with the implementation of the SREC solicitation program. These cost are roughly 5 percent of Delmarva's total SREC compliance cost (Delmarva Power, 2014).

The Delmarva SREC Solicitation Program has promoted some market stability by procuring SRECs based on the company's expected future SREC compliance needs. This is in contrast to other RPS-based state solar incentive models where market supply and demand may become imbalanced leading to periods of over- and under-supply. Delaware's approach of placing the RPS obligation on the distribution utilities instead of its electricity suppliers also decreases the potential for boom-bust cycles as the distribution utility is able implement a compliance strategy that takes into account future obligations. While the program's annual solicitations have been relatively small, these were each tailored to the company's expected compliance needs based on the legislatively established RPS schedule.

2.5 Connecticut ZREC Program

2.5.1 Introduction

Like Massachusetts, Connecticut has a Renewable Portfolio Standard (RPS) that is assessed as a percent of total load served on all electricity providers (including competitive retail suppliers) for each of three classes. Connecticut's Class I is comparable to the Massachusetts' Class I, with some material eligibility differences. Compliance is demonstrated by the purchase and retirement of Renewable Energy Credits (RECs). Connecticut's RPS ramps up to 20 percent by 2020 for Class I RECs, which includes production from biomass (with some emissions restrictions), small hydroelectric, wind, tidal, and solar photovoltaic plants, generally without a vintage threshold. There is an Alternative Compliance Payment (ACP) of $55/MWh which serves as a price cap.

The Class I obligation has typically been served by out-of-state generation, and mostly by legacy biomass and landfill gas generators due to the lack of a vintage requirement. The Connecticut Zero-Emissions Renewable Energy Credit, or ZREC, program is a long-term contracting program for Class I RECs designed to incentivize the development of distributed generation resources in the state (CT PURA, 2011). It is worth clarifying that while all RECs generated under the ZREC program are used to offset Class I REC obligations, the ZREC program is not a specific carve-out of the Class-I market, as with the Mass. SREC market. The ZREC program was introduced as a part of suite of programs through Public Act 11-80, passed in July 2011 (State of Connecticut, 2011). Given the lack of in-state wind potential, the main focus of the programs was solar and fuel cell projects. These programs complement recent long-term contracting efforts that have selected new, regional wind resources to contribute to the state's Class I REC supply.

In Connecticut, there are only two Electric Distribution Companies (EDCs) – Connecticut Light and Power (CL&P) and United Illuminating Company (UI). These companies carry about one-third of the RPS obligation, with the rest being borne by competitive retail suppliers. The Connecticut Public Utilities Regulatory Authority (CT PURA), formerly known as the DPUC, administers the LREC/ZREC program and only has the authority to direct EDCs to participate in long-term contracting programs. Thus, UI and CL&P carry the full burden of the state's goals for distributed generation.

2.5.2 Policy Details

The ZREC program was established in conjunction with the Low-Emissions Renewable Energy Credit, or LREC, Program in 2011 pursuant to Sections 107, 108 and 110 of Public Act No. 11-80 (State of Connecticut, 2011). Implementation has occurred under the auspices of the CT PURA. The intention of this program is to incentivize the development of distributed generation in the state of Connecticut. The ZREC program is open to wind, solar and small hydroelectric projects up to 1 MW, while the LREC program is open to all of the above, along with natural gas fuel cells, landfill gas, and biomass gasification units up to 2 MW. Both programs offer 15-year fixed price contracts with the state's electric distribution companies (EDCs) for RECs, all of which are Class-I eligible (CT PURA, 2011).

The ZREC program is operated on a fixed-budget basis, with the two EDCS offering $8 million of new contracts once per year for six years, beginning in 2012. The LREC program has an additional $4 million of annual contract budget. It is important to note that this budget reflects the single-year contracted amount. Thus, at its peak, the ZREC program would cost $48 million per year (See Figure 11 for illustration of expense schedule). The total program budget is divided between the EDCs based on their respective share of total load served – 80 percent for CL&P and 20 percent for UI. The ZREC program (and its budget) is also divided by size categories.

Figure 11. LREC/ZREC Program Expenses Illustration
(The Connecticut Light and Power Company and the United Illuminating Company, 2011)

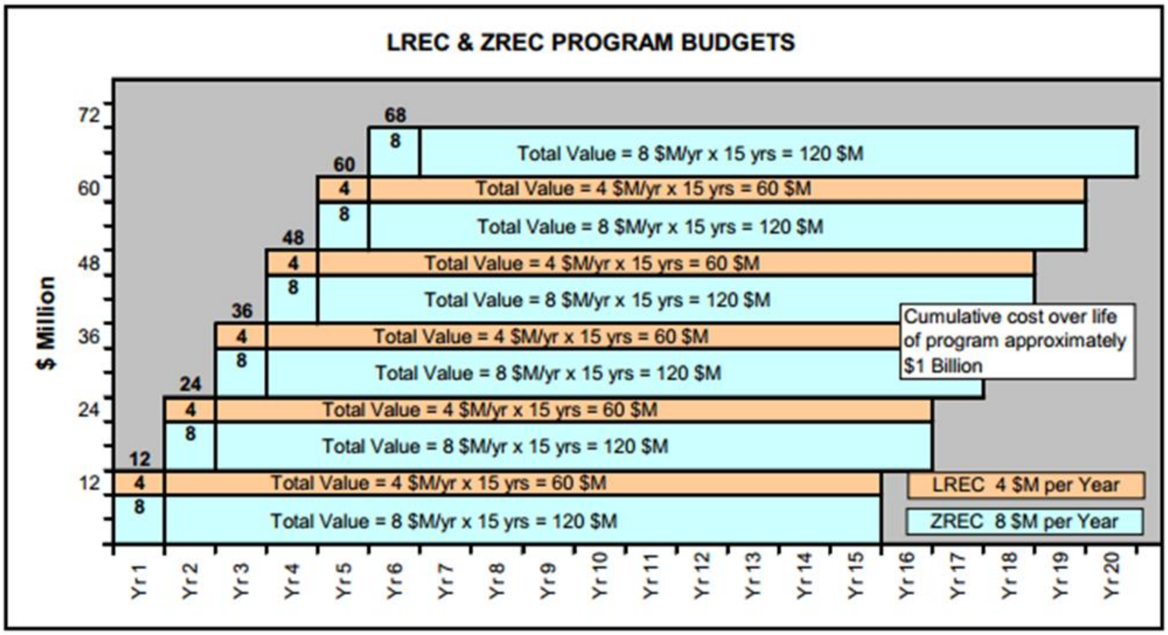


Table 15. Project Size Definitions and Annual Contract Budget

ZREC Project Category	Capacity Range	Total Solicitation Budget (UI & CL&P)	
		UI	CL&P
Small	0-100 kW AC	$0.533 M	$2.133 M
Medium	100-250 kW AC	$0.533 M	$2.133 M
Large	250-1000 kW AC	$0.533 M	$2.133 M

Each year, the EDCs offer a single, simultaneous solicitation for projects in their territory. The solicitation is limited to the Medium and Large ZREC categories, which are selected on a least-cost basis. Bids are evaluated for each EDC separately, and projects are awarded contracts as-bid until the full budget is exhausted or there are no more applications. The only exception to the least-cost provision is for projects including technologies researched, developed or manufactured in-state. These projects are assessed at a cost 10 percent below their actual bid price. The Small ZREC program is administered as a fixed price tariff program with a competitively-derived price set at 110 percent of the weighted average bid price of selected Medium ZREC projects. These projects are selected on a rolling admissions basis, with tie-breaking procedures in place for rounds in which the program is oversubscribed on the first day.

The price cap for all sectors of the ZREC program is $350/REC in Round 1 and decreasing by round over time. Each year, CT PURA may lower the program cost cap by 3-7 percent according to multiple factors including actual bid prices from the previous year and expected changes in installed costs (The Connecticut Light and Power Company and the United Illuminating Company, 2011). Across all sectors, projects will be notified if and when their bid has been selected, at which point the applicant must execute a contract with the applicable company and submit the required performance assurance. This deposit is equal to a percentage of the maximum annual quantity of ZRECs multiplied by the contract price. This percentage is 20 percent for Large ZREC projects, 10 percent for Medium, and 5 percent for the Small ZREC category (The Connecticut Light and Power Company and the United Illuminating Company, 2011). Projects may also opt to terminate their application at this time, in which case a contract will be offered to the next projects (or projects) in the queue for which budget is available. In any year where the full budget is not utilized, the EDC may be directed to hold an additional solicitation, and/or shift budget between size categories to ensure that the program's funds are fully utilized. Excess budget may also be rolled into future years' solicitations.

Once a project's contract is executed, it has until its contracted Delivery Term Start Date plus a 12-month grace period to reach commercial operation. This provides a roughly two-year development window. Regardless of the project's actual online date, its 15-year contract term will begin on the Delivery Term Start Date. The relatively long development window has both benefits and drawbacks, as it gives projects an appropriate amount of time to reach commercial operation, but does not regularly clear out undeveloped projects. This results in long delays in budget reconciliation and capacity recycling into future rounds.

Rounds 1 and 2 both attracted sufficient bids such that the full budget could be allocated for each market segment in a single solicitation. In each round, minor adjustments were made to shift budget between sectors such that surpluses could be pooled to accommodate an additional project or projects. All of these adjustments require PURA approval. Any remaining budget surpluses are rolled into the following year's solicitation. Round 3 was the first round in which a program sector was undersubscribed due to front-end attrition of projects. In this case, an additional solicitation was held to fully contract the budgeted amount.

Table 16. Total and Accepted Number of Bids by EDC and Round

Program Category	EDC	Round 1		Round 2		Round 3	
		Total	Accepted	Total	Accepted	Total	Accepted
Large ZREC	CL&P	140	21	52	19	78	32
	UI	22	6	12	4	8	8
	Total	**162**	**27**	**64**	**23**	**86**	**40**
Medium ZREC	CL&P	113	47	157	70	113	95
	UI	37	13	35	24	50*	27*
	Total	**150**	**60**	**192**	**94**	**163**	**122**
Small ZREC**	CL&P	484	214	460	277	N/A	N/A
	UI	107	31	108	51	N/A	N/A
	Total	**591**	**245**	**568**	**328**	N/A	N/A

**After receiving insufficient interest in the first solicitation, UI was directed by CT PURA to re-open the Medium ZREC solicitation to additional bids. This total reflects the additional applications received during that process.*

*** CL&P's "accepted" numbers represent projects with executed contracts. UIs are noted as "Selected". May not be consistent.*

Table 17. Total and Accepted Capacity (MW) of Bids by EDC and Round

Program Category	EDC	Round 1		Round 2		Round 3	
		Total	Accepted	Total	Accepted	Total	Accepted
Large ZREC	CL&P	94.3	12.2	34.2	12.2	65.3	27.6
	UI	12.1	2.6	7.2	2.4	5.9	5.9
	Total	**106.4**	**14.8**	**39.4**	**14.6**	**75.0**	**32.7**
Medium ZREC	CL&P	21.5	8.8	30.2	14.2	24.5	18.1
	UI	7.1	2.5	6.4	4.4	9.7*	5.1*
	Total	**28.6**	**11.3**	**36.6**	**18.6**	**30.4**	**24.0**
Small ZREC	CL&P	22.0	9.2	23.3	13.4	N/A	N/A
	UI	6.7	2.3	6.2	2.9	N/A	N/A
	Total	**28.7**	**11.5**	**29.5**	**16.1**	N/A	N/A

**After receiving insufficient interest in the first solicitation, UI was directed by CT PURA to re-open the Medium ZREC solicitation to additional bids. This total reflects the additional capacity contracted during that process.*

The program has been successful in attracting bids at prices below those for SRECs on the spot market in neighboring Massachusetts. The results of each solicitation to date are summarized in the table below. This data presents only the average bid price for selected projects. Though individual bid prices are protected, it is clear that the range of bid prices has narrowed considerably over time. In Round 1, the average price of selected bids came in $30-40/MWh less than the average price of all bids. By Round 3, this gap dropped to $0-10. This could signal developers generally providing more competitive bid prices or the more expensive developers falling out of the market.

Table 18. Weighted Average Prices of Selected Bids for ZREC Program (Calculated Tariff Price for Small ZREC Category)

Program Category	EDC	Round 1	Round 2	Round 3
Large ZREC	CL&P Weighted Average	$101.36	$76.63	$59.35
	UI Weighted Average	$117.27	$90.43	$65.76
	Total Weighted Average	**$104.13**	**$78.87**	**$60.48**
Medium ZREC	CL&P Weighted Average	$149.29	$93.65	$73.61
	UI Weighted Average	$135.36	$102.31	$76.40
	Total Weighted Average	**$146.23**	**$95.70**	**$74.22**
Small ZREC	CL&P Calculated Price	$164.22	$103.01	$80.97
	UI Calculated Price	$148.89	$112.54	$84.04
	Average Calculated Price	**$161.15**	**$104.92**	**$81.59**

2.5.3 Key Interactions

The ZREC program differs from some renewables contracting programs in that the EDCs are only contracting the RECs associated with production, and that energy and capacity are not included in the transaction. As a result, ZREC premiums are directly dependent on the current and projected value of electricity and capacity in Connecticut, as well as the availability of virtual net metering for larger projects. Projects are able to get financing based on host-owned expected returns (based on expected savings versus retail rates) and third-party-owned projects, based on PPA sales to the host. The degree to which there is risk associated the future retail rate changes is comparable to the situation in the Massachusetts SREC market; and like that market, developers may hedge that risk through fixed price PPAs with project hosts. The ZREC market also interacts (to a limited extent) with the LREC market and the broader Class I Renewable Energy Credit market. Although solar is eligible to participate in both of these markets, the price of RECs in both is well below that of ZRECs and is likely to stay that way for the duration of the program. In theory, if the program was extended to the point at which solar reached parity with LREC or other Class I resources, LREC and ZREC prices would converge at a level below Class I prices, reflecting the financing benefits of a long-term contract, and solar projects up to 2 MW would have access to this mechanisms through LRECs.

Net metering is available to RPS Class I Renewable Energy Sources with a generating capacity of 2 MW or smaller in Connecticut. Any net excess generation is credited at the Electric Distribution Company's avoided wholesale power cost at the end of twelve months. RECs associated with the net metered facilities are retained by the customer. Unlike Massachusetts, Connecticut does not have an aggregated net metering cap. Currently, virtual net metering is only available to municipal, state and agricultural customer hosts. A virtual net metering facility must be a RPS Class I facility with a generating capacity of 3 MW or smaller or a RPS Class III facility (primarily combined-heat and power systems). Excess generation is credited at the sum of (i) the generation service component and (ii) the transmission and distribution components at a declining schedule[30]. The virtual net metering program has an annual statewide cap of $10 million virtual net metering credits (apportioned to each of the state's Electric Distribution Companies based on consumer loads). Each customer class (i.e. agricultural, municipal and state) must not receive more than 40% of the total virtual net metering budget available for each company. Connecticut currently does not authorize community-shared solar installations, although a community-shared clean energy facility pilot was proposed in the 2015 legislative session.

2.5.4 Impacts and Observations

To date, there have been three rounds of solicitations under the ZREC program. The program has attracted a large number of bids across all sectors. To date, almost all of the ZREC bids (both offered and selected) have been solar photovoltaic projects.[31] Selected bids are diverse in terms of project size, with projects falling across the range of eligibility for each category.

Reviewing the list of participating project developers, the Connecticut ZREC market appears very similar to the Massachusetts market with a mix of local and national developers. The detailed bid data for Round 3 has not been released yet, so it is premature to speculate on trends over time, but it appears that a healthy level of diversity is present in the market. Similarly, anecdotal evidence suggests that both municipalities and private houses are engaging in offtake agreements. This data is not published, making it difficult to speculate on how this has changed over time.

In total, between 400 and 450 MW of solar is expected to be contracted and built through the ZREC program, with all projects online by 2019. This results in a peak installation rate of roughly 100 MW/year from 2015-2017. Broken down by sector, the ZREC program should support roughly 125 MW of small solar (<100 kW), 150 MW of medium projects (100-250 kW) and 160 MW of large projects (>250 kW). Contracted capacity in the 2015 and 2016 solicitations is expected to continue to increase as bid prices fall, with a contraction in 2017 after the expiration of the ITC. This volatility is one of the side effects of a fixed-budget program, and could be disruptive to developers attempting to ride out an already difficult time in the market.

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[30] 80% of transmission and distribution charges in the first year of commercial operation; 60% in the second year; and 40% in the third year.

[31] Four small hydro projects were selected in Round 2 and two were selected in Round 3. In Round 1, three small hydro projects and two wind projects bid into the solicitation and were not selected. The industry as a whole expects these technologies to play little if any role in future solicitations.

What is not reflected in any of the tables above is the rate of success for executing contracts with selected projects, and the additional fallout of projects for which contracts have been executed. There have been substantial front-end withdrawals across all sectors, detailed in Table 19 below. It is interesting to note that while front-end attrition for Large ZREC projects dropped significantly following the first round, they have stayed relatively constant for Medium projects and jumped substantially from Round 1 to Round 2 for small projects. Broadly speaking, however, roughly 35 percent of the ultimately contracted capacity dropped out pre-commitment over the course of the first three rounds for CL&P, with this figure dropping in successive rounds from 68 percent to 26 percent to 19 percent. The first round appears to be an outlier – anecdotal evidence suggests that a number of developers jumped in without fully understanding net metering rules or other constraints and pulled out as they learned their projects would not be financially viable; the next two rounds may be more indicative. This dynamic suggests that some speculative bidding has taken place, or perhaps more accurately, that the single procurement per year cycle forces submission of some bids that are insufficiently vetted. However, it also suggests that the performance assurance requirements are somewhat effective in shaking out untenable projects from the program early, clearing space for projects willing to provide performance assurance.

Table 19. Front-End Attrition Rates for CL&P ZREC Solicitations[32]

Event	Category	# Bid/ Applied	MW	Withdrawn After Selected	MW	# Fully Executed	MW
Year 1 RFP	Large ZREC	140	94.3	22	16.7	21	12.2
	Medium ZREC	113	21.5	13	2.4	47	8.8
	Small ZREC	484	22.0	33	1.5	214	9.2
Year 2 RFP	Large ZREC	52	34.2	4	3.2	19	12.3
	Medium ZREC	157	30.2	13	2.5	70	14.2
	Small ZREC	460	23.3	85	4.6	277	13.4
Year 3 RFP	Large ZREC	78	65.3	7	5.8	32	27.6
	Medium ZREC	113	21.5	14	2.7	95	18.1

To further examine the issue of speculative bidding, it is important to look at a number of other factors. First, the early rounds of the program have been plagued by long delays and high attrition rates among projects with executed contracts. The table below summarizes terminations and in-service delays for Connecticut Light and Power, which carries 80 percent of the program obligation. Round 1 saw roughly 25 percent of Medium and Large projects ultimately terminate their contracts, with four projects still not yet online. So far, attrition rates are much lower for Round 2, but with the majority of projects still not operational, the number of terminations here is likely to increase, perhaps substantially.

Table 20. LREC/ZREC Solicitation Performance – CL&P Contracts from Rounds 1 and 2[33]

Event	Category	Applied		Fully Executed		Active		Terminated		In-Service		Pending	
		#	MW	#	MW	#	MW	#	MW	#	MW	#	MW
Round 1	Large ZREC	140	94.3	21	12.2	13	8.2	8	4.0	12	6.3	1	1.9
	Medium ZREC	113	21.5	47	8.8	31	5.4	16	3.4	30	5.0	1	0.4
	Small ZREC	484	22.0	214	9.2	180	7.6	34	1.6	115	3.5	65	4.1

[32] Data summary provided by Northeast Utilities January 27, 2015.
[33] Data summary provided by Northeast Utilities January 27, 2015.

Round 2	Large ZREC	52	34.2	19	12.3	18	11.4	1	0.9	3	1.4	15	10
	Medium ZREC	157	30.2	70	14.2	68	13.8	2	0.4	25	4.7	43	9.1
	Small ZREC	460	23.3	277	13.4	275	13.3	2	0.1	35	0.6	240	12.7

To estimate the number of ultimately successful projects, one can apply an assumed rate of success to the pending projects listed in the table above. In Table 21 below, we estimate a total attrition rate assuming that that the historical attrition rates serve as a proxy for the attrition from the pending capacity.[34] This calculation is made and applied by round and sector.

Table 21. Assumed Total Capacity Reaching Commercial Operation: CL&P Rounds 1 and 2[35]

Event	Category	Fully Executed		Projects Currently Operating		Assumed to Reach Comm. Operation		Assumed % Reaching Comm. Operation	
		#	MW	#	MW	#	MW	#	MW
Round 1	Large ZREC	21	12.2	12	6.3	13	7.5	60%	61%
	Medium ZREC	47	8.8	30	5.0	31	5.2	65%	60%
	Small ZREC	214	9.2	115	3.5	165	6.3	77%	69%
Round 2	Large ZREC	19	12.3	3	1.4	14	7.5	75%	61%
	Medium ZREC	70	14.2	25	4.7	65	13.1	93%	92%
	Small ZREC	277	13.4	35	0.6	262	11.5	95%	86%

Clearly, the attrition rates in Round 2 are well below those in Round 1 for most categories. However, using the methodology described above, one could expect more than 1/3 of the total capacity entering into Large ZREC contracts to fail to reach completion. To address the overall project attrition issue, CT PURA recently revised the program rules to discourage speculative bidding and encourage voluntary self-policing of the project pipeline. These changes move up the timeline for performance assurance delivery, require an affidavit from the land-owner acknowledging an agreement with a single project (to prevent multiple bids per site), and provide a 20 percent performance assurance refund for projects that voluntarily terminate before the required in-service date.

To help understand whether the reported weighted average price of selected bids is indicative of successful project prices, or whether speculative bidding causes disproportionate dropout of lowest bids, we examined the weighted average bid price for projects that have not yet dropped out compared to the average across the full pool of executed contracts. If speculative bidding was a pervasive problem that distorts the reliability of selected price data, one would expect that the weighted average price of completed projects would be higher than the weighted average across all selected projects. Table 22 below provides this comparison for the CL&P bids and contracts awarded in the first two rounds of the program.

[34] Percent attrition for pending projects equals the quantity of terminations divided by the sum of terminations and operating projects (i.e., projects that have reached a definitive end-point).
[35] Data summary provided by Northeast Utilities January 27, 2015.

Table 22. Weighted Average Bid Prices for All, Selected and Completed CL&P Projects[36]

Event	Category	Weighted Average BID price/REC	Weighted Average Price/ REC for all selected projects	Weighted Average Price/REC for 'active' projects[37]
Year 1 RFP	Large ZREC	$138.03	$101.36	$104.13
	Medium ZREC	$179.85	$149.29	$146.83
	Small ZREC	$164.22	$164.22	$164.22
Year 2 RFP	Large ZREC	$87.86	$76.63	$83.49
	Medium ZREC	$106.75	$93.65	$88.85
	Small ZREC	$103.01	$103.01	$103.01

The current snapshot data above – which is incomplete, since additional attrition is expected - reveals that for Large ZREC projects, the weighted average price of completed projects is, in fact, higher than that of the full selected bid pool. For the Medium ZREC category, the opposite is true. A possible explanation for this is that while some speculative bidding may be taking place among larger projects, the diversity of sites and associated challenges for medium projects creates an environment in which bid price is not the primary driver of project success or failure. This metric will be worth watching as the pending projects move to either completion or termination, to get a more complete picture of the true prices yielded by the program.

Based on participation (both in number and prices of bids) in Round 3, it appears the race to the bottom has slowed considerably, though it is unclear if this is a result of the program maturing or of the new rules propagated by CT PURA. In general, the level of competition is dropping noticeably from round to round. While it is difficult to draw definitive conclusions, this could be due to either saturation of good solar sites (i.e. independent of the incentive mechanism) or competitors leaving the market (perhaps due to the insufficient margins, a direct result of the incentive mechanism). It is worth highlighting that Round 3 is the first round in which additional solicitations were required for any category, a significant departure from the oversubscription of the previous two rounds. Looking ahead, there are three additional procurements planned for 2015, 2016 and 2017. It is likely that attrition from early rounds of the program will shift additional budget into these procurements, and that an additional year (or more) of solicitations may be required to fully spend the committed funds. This budget shift may also help to offset the higher bid prices expected in 2017 following the expected loss of ITC and preserve a smoother annual installed capacity trend.

It is our expectation that regardless of the availability of the ITC, ZRECs will continue to be priced well above Class I RECs. Whether EDCs choose to retire ZRECs to meet their own Class I REC obligations or resell them into the market, the companies are allowed to recover the full costs of the program from distribution ratepayers. While the RECs are purchased at above-market prices, the program does promote the development of in-state resources, which is largely absent from the broader Class I market. With this comes in-state jobs and other indirect economic benefits, reliability benefits, and fuel diversity for Connecticut ratepayers. The competitive procurement approach seeks to achieve this suite of benefits at the lowest possible cost to ratepayers. The fixed income stream provides more certainty to projects trying to secure financing, and ultimately driving a lower cost of capital and lower total development cost. This is why, at the surface, the ZREC program appears to drive development at a cost well below that of market-based programs like the Massachusetts SREC markets.

[36] Data summary provided by Northeast Utilities January 27, 2015.
[37] Active projects are competed and pending.

It is unclear whether the attrition that has occurred in the market to date has been at the bottom of the cost stack, such that the weighted average bid cost represents an artificially low program cost, but we expect the EDCs to release analysis of this issue in the near future. There are likely some less obvious economic impacts associated with the competitive procurement approach particularly one with infrequent solicitations. In contrast to procurement mandates, such as RPS tiers or standard offers, which allow for a relatively steady stream of sales, design, financing and installation workflow that is conducive to establishing long-term jobs, episodic procurements represent bursts of activity that are difficult to staff for, often leading to short-term jobs and greater use of mobile labor.

2.5.5 Summary Observations and Lessons Learned

In its first three rounds of procurements, the ZREC program has successfully contracted for the full budgeted amount for both EDCs (although Round 3 required a second solicitation in some categories), almost all of which has been for solar PV projects. Similarly, the Small ZREC procurement has been heavily oversubscribed at the fixed price in both of the first two rounds. All of these contracts have come at rates well below spot prices for SRECs in Massachusetts. However, there are additional complexities.

First, the ZREC program contracts project RECs for 15 years, compared to the 10-year eligibility of an SREC II project. Thus, the EDCs are paying above-market rates for Class I RECs for an additional five years. It is also not clear that the market can actually support robust development at the prices that have been offered to date. The single procurement per year fosters an environment of speculative bidding, with developers hoping the economics pencil out before the development window closes. Low commitment hurdles and collateral requirements do little to prevent this behavior. While the EDCs argue that the single procurement is necessary to control the administrative costs of the program, the market has already seen long delays and high attrition rates from projects selected in the first two rounds. Municipalities have also countered the administrative cost claims with complaints that the current system often results in a great deal of effort being put into projects that are ultimately not selected and shelved for another year (if ever revived). The state has promulgated rules to help limit attrition and reduce termination lag time, but it remains to be seen how effective this will be. It seems very unlikely that the measures will address the issues raised by municipalities.

Ultimately, the shortfalls of Connecticut's ZREC program could potentially be avoided in Massachusetts if addressed from the beginning. As a larger market, there should be more opportunities in Massachusetts for more regular solicitations, and requiring higher development hurdles for bidders is simply a matter of policy design. If done correctly, it is reasonable to believe that enacting a program similar to the LREC/ZREC program in Massachusetts could achieve similar levels of development at a lower cost to ratepayers and with greater certainty for developers than the SREC market structure currently offers.

2.6 New Jersey Electric Distribution Company Contracting, Direct Ownership and Financing Programs

2.6.1 Introduction

New Jersey has consistently had one of the most robust state solar markets in the United States. This market growth has been driven by a succession of policies over the past several years, from a series of rebate programs in the latter part of the last decade to the current solar carve-out in the state's renewable portfolio standard (RPS). The current state-wide renewable goal is 17.88 percent by 2021 while the current RPS requires 4.1 percent to the state's retail electricity to come from in-state solar by 2028 (Assembly, New Jersey State and General, 2012).[38] This compliance obligation, and the annual schedule to reach it, have changed on several occasions over the past years through legislative action in response to greater than anticipated solar market growth causing SREC market price volatility.

As with several other East-coast states with large solar markets, New Jersey has a deregulated energy market and participates in the PJM Regional Transmission Organization. The state has four investor owned utilities, Public Service Electric & Gas (PSE&G), Rockland Electric Company (RECO), Jersey Central Power & Light (JCP&L) and Atlantic City Electric (ACE). Of these, PSE&G is the largest electric distribution company in the state, supplying a little over 50 percent of the state's load in 2012 (State of New Jersey, Board of Public Utilities, 2009).

Unlike the Massachusetts SREC market, the New Jersey market obligation is legislatively fixed and does not include an SREC price floor. This has, in part, contributed to significant market volatility (in terms of both the pace of development and SREC price) and SREC incentive price uncertainty for project owners. During the state's transition from a rebate-based market to an SREC solar incentive market model, the New Jersey Board of Public Utilities (NJBPU) convened a stakeholder process to explore programmatic methods for supporting solar financing within the SREC market model. At the time, there was concern that an SREC market model without predictable cash flows from SREC sales would hinder market development as project developers would be unable to secure adequate financing. In response to these concerns, three utility-sponsored programs were developed to ensure some portion of New Jersey solar installations would benefit from long-term SREC price certainty. (State of New Jersey, Board of Public Utilities, 2009) These are:

- The PSE&G Solar4All initiative
- The PSE&G solar financing initiatives
- The ACE, RECO and JCP&L long-term solar contracting programs

These ancillary programs are the focus of this policy brief.

2.6.2 Policy Description

2.6.2.1 Solar4All Program

The Solar4All program is a direct utility solar ownership program implemented by PSE&G. This initiative was originally approved in July 2009 and allows PSE&G to procure 80 MW of solar on brownfields, grayfields, and urban enterprise zones. The program also authorized installation of PV on company-owned utility poles (State of New Jersey, Board of Public Utilities, 2009). The second iteration of Solar 4All was approved by the New Jersey Board of Public Utilities in May

[38] New Jersey has defined a solar goal for 2028 but currently only has an established state-wide RPS goal for 2021. The state's 2021 solar goal is 3.47%

of 2013. This phase of the program is focused on utility ownership of PV systems on underutilized land such as brownfields and landfills as well as implementation of pilot tranches of utility-owned PV designed for electricity system resiliency, underutilized government facilities and parking lot applications. Table 23 below shows the expected total MW of PV installed and owned by PSE&G in the Solar4All Extension program.

Table 23. PSE&G Solar4All

Market Segment	Total Solar4All Extension MW
Landfills and Brownfields	42 MW
Underutilized Government Facilities	1 MW
Grid Security/Storm Preparedness	1 MW
Innovative Parking Lot Applications	1 MW

PSE&G recovers its investment in the Solar4All program as it would other utility infrastructure investments and by selling energy generated by Solar4All systems into the market. Any revenue from sale of energy or SRECs from the systems are refunded to ratepayers through reductions in the company's overall Solar4All cost recovery mechanism. In its most recent program filings with the NJBPU, PSE&G argued that the program promoted a number of key public policy goals including:

- Solar development on otherwise unused brownfields and landfills;
- In-state job creation;
- Assist with the development of a market for new solar applications. (State of New Jersey, Board of Public Utilities, 2013)

The Solar4All extension program has also been structured in order to help alleviate potential SREC market oversupply. As part of the stipulation authorizing the initiative, PSE&G agreed to stagger system installations over several years in order to prevent market oversupply that could significantly decrease SREC market prices (Belden, Michaelman, Grace, & Wright, 2014). The structure of this program may help support market stability in future years by providing ongoing market support during times of limited market activity or by reducing market SREC supply during oversupply conditions. Additionally, the competitive nature of the utility solicitations for each solar installation may support state-wide goals of lowering overall SREC compliance costs. An initial analysis concluded that, once completed, that program would increase annual ratepayer costs by an average of 0.329 percent (State of New Jersey, Board of Public Utilities, 2013).

2.6.2.2 PSE&G Solar Loan Program

In addition to operating the Solar4All program, PSE&G has implemented a series of solar financing initiatives. Currently in the third iteration of the program, the Solar Loan III Program provides participating PV system owners with the ability to finance a portion of the upfront cost of their systems and repay the debt with SRECs at a predetermined price. PSE&G has been authorized to provide loans for 97.5 MW of PV under the latest program funding round. In an effort to promote market diversity, this capacity is allocated to four project types:

- Large non-residential systems (>150kW <= 2 MW);
- Small non-residential systems (<= 150kW);
- Residential systems;
- Aggregations of residential systems;
- Landfills and Brownfields (<= 5MW).

PSE&G conducts regular solicitations (four to six times a year) in which system owners bid an SREC floor price into a competitive solicitation. This floor price is the minimum value that SRECs transferred to PSE&G will receive to pay off the solar program loan. If market prices for SRECs should increase above the awarded system floor price, SRECs transferred to PSE&G will be monetized at the higher market price, allowing system owners to pay back their loans more quickly. Systems which bid the lowest floor prices are awarded loans until the available capacity for the solicitation round has been fully allocated. Solar loans for the program have a 10-year tenor and a fixed interest rate of 11.179 percent. Administrative fees associated with the costs of the program are paid by winning bidders and incorporated into the total loan amount.

Most solicitation tranches under the Solar Loan III Program have been undersubscribed with the notable exception of the Landfill and Brownfield market segments during the first two rounds of the program. Table 24 below lists the weighted average SREC floor price for winning bidders for the first five Solar Loan III Program rounds. The first solicitation took place in late 2013 with the fifth solicitation awarding contracts in December 2014.

Table 24. Solar Loan III Average Weighted SREC Prices

System Size	Solicitation #1	Solicitation #2	Solicitation #3	Solicitation #4	Solicitation #5
Large non-residential systems (>150kW <= 2 MW)	$177	$205	$209	$195	$195
Small non-residential systems (<= 150kW)	$235	N/A	$256	$230	$245
Residential systems	$258	$262	$275	$274	$276
Aggregations of residential systems	N/A	N/A	$214	$214	N/A
Landfills and Brownfields (<=5MW)	N/A	$188	N/A	N/A	N/A

Once transferred to PSE&G, SRECs are sold into the market and revenues from these sales are used to offset program costs. Any costs associated with the program not recouped by PSE&G directly from program participants are recovered through the state's RGGI surcharge mechanism (State of New Jersey, Board of Public Utilities, 2013). In its filings, PSE&G estimated that the average non-participating ratepayer would see a maximum bill increase of $2.12 annually due to the Solar Loan III Program.

Average prices in the Solar Loan III Program have not decreased over the course of the program and have been significantly higher than publicly available SREC spot market prices (SRECTrade, 2015). Additionally, most of the solicitation tranches have been consistently under-subscribed, potentially due to the relatively high interest rates offered.

2.6.2.3 EDC Solicitation Programs:

As part of initial efforts to support financing availability for solar PV projects participating in the state's SREC market, ACE, JCP&L and RECO proposed to jointly implement a long-term SREC contracting program. The first iteration of this program was launched in August of 2009. Under this first-phase program, the participating utilities held eight coordinated solicitations over a two-year period. Solicitation participants bid SREC prices for long-term purchase contracts (10-15 years). In order to support market diversity, the program had solicitation tiers for small systems (0-50kW), medium sized systems (50-500kW) and large systems (0.5-2MW). (New Jersey Economic Development Corporation, 2011). Winning solicitation bidders were awarded contracts based on as-bid prices. As SRECs were generated, the distribution companies pooled SRECs obtained through the program with SRECs from the PSE&G initiatives (see above) and sold them into the market on a quarterly basis.

In the first phase of the program, ACE, JCP&L and RECO signed long-term SREC contracts totaling 63.4 MW. Average contracted SREC prices ranged from a high of $460 per MWh to $232 per MWh. (Rutgers Center for Energy, 2012). Table 25 below shows the weighted average SREC price for solicitations in each of the utility territories by year.

Table 25. Weighted Average SREC Price (2010 – 2012)[39]

Energy Year	ACE	JCP&L	RECO
2010	$373	$407	$460
2011	$425	$423	$384
2012	$253	$232	$380

As part of extended efforts to reduce market price volatility and support long-term financing for PV systems, the NJBPU authorized a second phase of this solicitation program in May of 2012. This program will launch in 2015 and will have a similar structure to the earlier program. The total expected capacity procured through the new initiative is 180MW over a three-year period and, as with previous program iteration, the solicitations will have separate tiers to help promote market diversity (State of New Jersey, Board of Public Utilities, 2013).

2.6.3 Key Interactions

The ancillary policies discussed in this profile exist within the framework of the New Jersey solar RPS carve out. Additionally, solar PV systems in New Jersey typically qualify for net metering, although some larger PV systems in the state sell power directly into the PJM wholesale market. These 'grid-supply' projects were a major driver of market growth, but recent legislation has moved to cap development in this market segment and require NJBPU approval for project through a first-in-time approval process.[40] State net metering laws allow for single-customer meter aggregation for government entities, but do not support broader virtual net metering.

2.6.4 Impact and Observations

New Jersey has consistently had one of the largest solar PV markets in the United States over the past several years. This market has been driven largely by the state's solar carve out in its renewable portfolio standard. The ancillary policies discussed in this section have supported public policy priorities related to the state's solar market including creating long-term price certainty for a segment of the state's PV system owners and increasing state solar capacity through utility-owned PV systems. These programs, through regular procurements, have helped foster market stability and have been coordinated to ensure that they do not promote SREC market price volatility. It should be noted, however, that the New Jersey solar market has experienced periods of volatility, particularly in late 2011 and early 2012 when the market grew rapidly as developers attempted to secure expiring federal incentives while taking advantage of high expected future SREC values (Belden, Michaelman, Grace, & Wright, 2014).

Market interest for these ancillary programs has been mixed, with some program solicitations being oversubscribed while others have received limited market interest. For instance, the market response to the latest iteration of the PSE&G loan programs has been less competitive in some market categories than others. A full analysis of the drivers behind this market dynamic is beyond the scope of this summary, however the complexity of the program as well as the relatively high interest rate (11.179 percent) may serve to limit participant interest, particularly amongst less sophisticated prospective residential PV owners.

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[39] This data represents the latest available data. New solicitation rounds have been approved, but have not yet been implemented.

[40] This market regulation is analogous to the "Managed Growth" market segment in the Massachusetts SREC II program.

Each of the three policies of interest have competitive aspects that promote incentivizing least-cost systems. Systems installed through the PSE&G direct ownership program are purchased through a competitive procurement process. Similarly, both long-term contracting programs conduct regular competitive solicitations, awarding contracts to the most competitive bids. Additionally, the latest iteration of the PSE&G solar loan program includes a competitive component that awards long-term SREC contracts on a competitive basis. As with all competitive procurement programs, some proportion of systems that have been awarded contracts will not be built. This can happen for a number of reasons, from developers bidding overly aggressively in order to win contracts to technical issues that were unknown at the time of the solicitation. Contract failure rates for the programs discussed in this profile are not available, however this concern is worth further exploring if Massachusetts policymakers move forward with similar competitive bidding programs.

The New Jersey EDCs aggregate and re-sell the SRECs procured through these programs on a quarterly basis through a market auction mechanism. Proceeds from this auction are applied to the costs of the program, lowering the overall ratepayer cost for these initiatives. During periods when the auction price is above the average price paid by through the EDC programs, ratepayers may see a net benefit on their bills. During periods when the auction prices are lower than the average contract prices, these programs would add costs to the distribution portion of a ratepayer's bills. In accounting for the costs and benefits of these programs, it is critical to remember that ratepayers ultimately pay the costs of supplier RPS compliance, meaning that any savings seen on the distribution portion of ratepayer's bill due to high SREC prices attained in the auction may be reduced through higher supplier RPS compliance costs.

The ancillary policies described herein support the New Jersey SREC market by promoting long-term incentive price certainty and creating a utility-supported sub-market. These programs have helped moderate potential solar market volatility in New Jersey. The competitive nature of both the utility long-term contracting programs and the PSE&G financing program have established incentive levels through price competition. Two of these three ancillary policy mechanisms have analogues in the current Massachusetts solar market framework, with Massachusetts EDCs able to own their own solar generation and the pending solar MassCEC/DOER supported residential solar loan programs.[41] Similarly, the price floor mechanism in the Massachusetts SREC market is intended to create long-term SREC price certainty, a goal of the New Jersey EDC long-term contracting program.

[41] Additionally, the Massachusetts Section 83A long-term contracting program within the Class I market has similarities to the New Jersey EDC solicitation programs.

2.7 Vermont SPEED Standard Offer

2.7.1 Introduction

Vermont established the Sustainably Priced Energy Enterprise Development (SPEED) Standard Offer Program to encourage the development of, and enable financing for, renewable energy distributed generation in the state. Through the SPEED Standard Offer Program, Vermont provides long-term contracts of between 15 and 25 years, depending on the technology, to qualifying renewable energy generators less than or equal to 2.2 MW. Initially, contracts were awarded at an administratively-determined, fixed, standard offer price, akin to a feed-in tariff. Subsequent program changes converted the program to one in which contracts are awarded through a competitive bidding process (subject to a price cap). While Standard Offer remains in the program name, it remains a competitive process. The SPEED Standard Offer Program operates under the jurisdiction of the Public Service Board (PSB). The Vermont Electric Power Producers Inc. (VEPP Inc.) was selected as the program facilitator, and is responsible for both managing competitive procurements and administering the contract payments and collections through the state's utilities. The program began in 2009 with a 50 MW target and now includes legislative authority for up to 127.5 MW of contracts with solar, wind, biomass, landfill gas, farm methane, and hydroelectric generators by 2022. The SPEED Standard Offer program has created an active market for distributed generation in Vermont (Vermont SPEED Homepage, 2015).

VEPP Inc. began accepting applications for the initial 50 MW target in October 2009. The PSB implemented a lottery to assign applications accepted during the first day of the solicitation with random positions in the queue. Within minutes, applications were received far in excess of this programmatic cap. The PSB received over 200 applications, totaling more than 190 MW, during the program's first week. The applications were primarily from solar PV projects. In response, the PSB determined that no single technology should comprise more than 25 percent of the initial project queue, and required that such technology caps be reviewed regularly thereafter. This 25 percent technology cap remained in place until 2011, when the PSB elected to take projects off the waiting list by simply alternating between solar and wind projects until the program's initial 50 MW was fully subscribed (SPEED Program Rule, 2015).

The SPEED Program was established in 2005 under 30 V.S.A. § 8005 and § 8001 to promote long-term contracting with renewable generators and the development of in-state resources. It set renewable energy development goals which, if not met, would trigger adoption of an RPS. The first 50 MW of the Standard Offer Program was added as part of the Vermont Energy Act of 2009 (Act 45). The Vermont Energy Act of 2012 (Act 170) expanded the Standard Offer to 127.5 MW and mandated the use of a market-based mechanism to establish contract prices, which had previously been administratively determined. Unlike the rest of the region, Vermont's utilities continue to operate as vertically-integrated monopolies without providing retail choice. As such, the production and cost of Standard Offer contracts are allocated to Vermont's four largest utilities[42] as well as the Vermont Public Power Supply Authority on behalf of the state's 14 municipal utilities (Vermont PSB Implementation of Standard Offer Program for SPEED (Dockets 7523 and 7533), 2015).

Overall, Vermont has created a strong policy environment for small renewable energy generators. It is difficult, however, to secure permits and public acceptance for larger projects. There is a robust net metering policy, including aggregate net metering, which is applicable to projects less than or equal to 500 kW[43] and is available in all utility

[42] Green Mountain Power, Burlington Electric Department, Vermont Electric Cooperative, and Washington Electric Cooperative.
[43] Up to 2.2 MW for military installations.

territories up to 15 percent of peak demand.[44] Net excess generation not used within twelve months is granted to the utility. The net metering customer retains all RECs (but is given the option to grant them to the utility). Act 99 of 2014 made several changes to the net metering rules intended to promote small-scale solar generation. First, the Act allows a utility to, at its own discretion, continue to accept solar net metering systems of 15 kW or less without the PSB's approval upon reaching the 15 percent cap. For other net metering systems, the utility can file a petition to raise the utility-specific cap with the PSB. Further, pursuant to Act 99, solar net metering systems of 15 kW or less will continue to receive a net metering rate of 20¢/kWh, while other net metering systems will receive a reduced rate of 19¢/kWh for no less than 10 years. Net metered systems are not eligible for the SPEED program. In the absence of rebates and other direct or performance-based solar incentives, net metering credits and the sales of RECs to RPS Class I markets in other states (e.g. Massachusetts) have been the major drivers for net metered solar projects in Vermont. When combining net metering credits, sales of RECs and reduction in technology costs, this revenue now appears sufficient to stimulate considerable behind-the-meter development activity.

Over the last several years, the state and local utilities have also offered a series of renewable energy tax credits, renewable energy adders, and numerous grant and loan programs, many of which flow through the Clean Energy Development Fund,[45] to support the state's SPEED goal of 20 percent statewide renewable electricity sales by 2017.[46] The CEDF was established in 2005 through Act 74 (30 V.S.A. § 8015) with a goal of increasing "the development and deployment of cost-effective and environmentally sustainable electric power sources (Clean Energy Development Fund Home, 2015). The CEDF was historically funded through contributions from Vermont Yankee and is currently funded through periodic allocations from the Vermont Legislature. Due to budget limitations, the 30 percent solar business tax credit expired in 2012, although the 7.2 percent personal investment tax credit remains. CEDF grant and loan programs are offered periodically through competitive solicitations.

Vermont has yet to establish a Renewable Portfolio Standard, although such a policy was recently proposed in the 2015 legislative session. Presumably, all Standard Offer contracts will be eligible to help fulfill some aspect of a future Vermont RPS.

The Standard Offer Program has generated a large amount of development activity across the state relative to the scale of state load – particularly for solar. Successful projects range in size from residential installations to the 2.2 MW program cap. While a significant amount of new capacity (approximately 45 MW) has been successfully installed, the program has also been characterized by substantial project attrition, described in detail below, as new market entrants grapple with the challenges of putting together successful renewable energy projects. This frequent project failure has been managed through the use of technology-specific waiting lists, from which projects are called upon when program capacity becomes available. The migration from administratively-determined prices to a market-based, RFP-driven structure appears to be reducing attrition by requiring developers to post security and have a better handle on all aspects of project feasibility prior to bidding (VT H.702, 2014, 2015).

2.7.2 Policy Description

The SPEED Standard Offer Program provides long-term contracts to qualifying renewable energy projects as follows:

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[44] Or the utility's 1996 peak demand, whichever is greater. This net metering cap was recently increased from 4% of peak demand.

[45] Which is housed within the Department of Public Service.

[46] Vermont also has a total renewable energy target schedule, which requires 55 percent of each retail electricity provider's annual electric sales to be met by renewable energy during the year beginning January 1, 2017, increasing by an additional 4 percent each third January thereafter, until reaching 75 percent on January 1, 2032. (Clean Energy Development Fund Home, 2015)

- Landfill gas (15 years)
- Biomass, farm methane, hydroelectric, and wind (20 years)
- Solar (25 years)

During the early program years, pricing was administratively-determined, similar to a feed-in-tariff, on an annual basis through a regulatory docket process. Contracts were awarded on a first-come, first-served basis. This annual price-setting process created a substantial time and cost burden on regulators and stakeholders. Since 2013 (as a result of the Vermont Energy Act of 2012), all pricing has been determined by competitive bidding – with price caps set at avoided cost on a technology-specific basis, with the exception of farm methane projects. This change was made to conform the program to clarifications issued by the Federal Energy Regulatory Commission ("FERC") in 2010 decisions which prohibited standard-offer rates established under state law from exceeding the PURPA avoided cost, but authorized states to employ a "multi-tiered" technology-specific avoided-cost structure in a standard offer program that takes into account state-law requirements to purchase electricity from particular sources of energy.[47] The solar avoided cost price cap is levelized, while all other technologies allow annual escalation of no more than 1.6 percent on no more than 30 percent of project cost.[48] Both the avoided cost price caps and the RFP process are established by the PSB. There is one competitive solicitation per year. Awards are made based on price, assuming all other eligibility criteria are met. Once a contract is awarded, projects have 24 months (solar and wind) or 36 months (all other technologies) to achieve commercial operation. All production is compensated at the successful bid price.

The programmatic goal of 127.5 MW has annual allocation targets, which are further divided by technology. Initially, the MW allocation for each technology was set at no more than 25 percent of the initial project queue. In June 2011, the PSB revised the technology guideline requiring the SPEED facilitator to admit projects on an alternative basis from the solar PV and wind waiting lists until the program was fully subscribed. The state is currently developing a new technology allocation methodology. The first 50 MW was made available in 2009 and – after significant project attrition[49] – was fully subscribed by early 2013 using the waiting list method described above to refill the program whenever project failure occurred. Incremental program MWs are offered through annual RFPs as follows: 5 MW per year for 2013-2015, 7.5 MW per year for 2016-2018 and 10 MW for 2019 through 2022. Each year, a portion of incremental capacity is reserved for ownership by Vermont utilities. This capacity is referred to as the Provider Block. The Provider Block is set at 0.5 MW for 2013-2015, 1.125 MW for 2016-2018 and 2.0 MW for 2019-2020. The SPEED statute allows for the possibility of exceeding the annual and total programmatic targets, to the extent that projects which are determined to provide sufficient benefit to the distribution system are not counted toward the programmatic MW cap. The PSB developed a screening framework regarding transmission-constrained and distribution-constrained areas to guide such determination. In May 2014, the PSB determined that there were no constrained areas where renewable generation projects would provide sufficient benefits with the potential exception of the Rutland area. The PSB directed Green Mountain Power (distribution company of the Rutland territory) to develop a Reliability Plan to identify whether SPEED standard offer projects could provide sufficient benefit to enhance system reliability in Rutland. As of the time this report is published, the Rutland area Reliability Plan has not yet been published.

Competitive bids are capped at an administratively-determined avoided cost, by technology, which is updated annually by the PSB. The PSB process is public and largely driven by stakeholder inputs. Stakeholders are invited to provide cost, performance and other market data and propose financing models consistent with FERC's rules to determine the

47 Cal. Pub. Util. Comm'n Et.al 132 F.E.R.C. ¶ 61,047 (July 15, 2010); Cal. Pub. Util. Comm'n Et.al 133 F.E.R.C. ¶ 61,059 (Oct.21, 2010)

48 To reflect the impact of inflation on operating and maintenance expenses.

49 As of September 23, 2014, over 35% of project capacity were withdrawn or deleted from the queue.

avoided cost (based on an efficiently sized and located facility) for each technology. The PSB will conduct a series of stakeholder discussions spanning multiple months to identify the appropriate avoided cost calculation methodology and prices. Such a process may be considered burdensome and costly, considering that new capacity development resulting from each of the program's annual solicitations is only 5 to 10 MW. Further, battles among stakeholders over appropriate models for avoided cost calculation in early rounds of the program have given way to less contentious and less involved proceedings focused on updating avoided costs in recent years.

Solar projects must bid a levelized price beneath the levelized cost cap. All other technologies may bid escalating prices, so long as such prices neither exceed the avoided cost cap nor escalate more than 30 percent of the project cost at more than 1.6 percent per year. Pricing also may not be front-loaded and decrease over the term of the contract. Under the RFP selection process, projects are ranked according to a levelized bid price. In its evaluation, the SPEED administrator uses a 9.75 percent target after tax return on equity as a discount rate to calculate and compare levelized bids.[50] Solar has a flat avoided cost schedule that maintains at the levelized cost cap for 25 years (the assumed project life).

The PSB set fixed, 25-year, Standard Offer rates for solar projects as follows:

- 2009: 30.0 ¢/kWh
- 2010: 24.0 ¢/kWh
- 2011: 24.0 ¢/kWh
- 2012: 27.1 ¢/kWh

The solar avoided cost rate, serving as the price cap for the RFP process, for both 2013 and 2014 is 25.7 ¢/kWh. The increase from 2011 to 2012 was likely, in part, due to the state ITC reaching its cap.

In order to encourage legitimate, realistic bidding and mitigate attrition, the PSB implemented a security requirement in the competitive procurement program. Projects submitting bids must include security of $10/kW of proposed AC capacity. This security is returned to projects that are selected and that achieve commercial operation. Projects that bid successfully but fail to execute the Standard Offer contract within 15 days of notification forfeit their security. The initial (non-competitive) program rounds did not include a security requirement, which may have unintentionally attracted highly speculative projects into the queue – only to increase the percentage of attrition later on. While it is too early to draw conclusions about whether the current security requirement has addressed this problem, only one (out of seven) projects selected by competitive bid has withdrawn from its Standard Offer contract to date.

In between contract execution and commercial operation, projects must demonstrate development progress. For example, a complete application for a Certificate of Public Good must be submitted to the PSB within one year[51] of executing a Standard Offer contract. As previously stated, solar projects must achieve COD within 2 years, and all other projects within 3 years. The SPEED facilitator has no authority to grant extensions.

2.7.3 Key Interactions

Within Vermont, renewable generators may elect to participate in either the Standard Offer or Net Metering Programs, but may not participate in both. Standard Offer contracts convey all energy, capacity and, with the exception of farm methane projects, renewable energy certificates (RECs) to the contracting utilities. Standard Offer projects may qualify to participate in other CEDF incentive programs, such as the loan program and the Solar & Small Wind Incentive

[50] This is intended to approximate the Vermont utilities' weighted average cost of capital.
[51] Except for hydroelectric projects requiring a license from FERC.

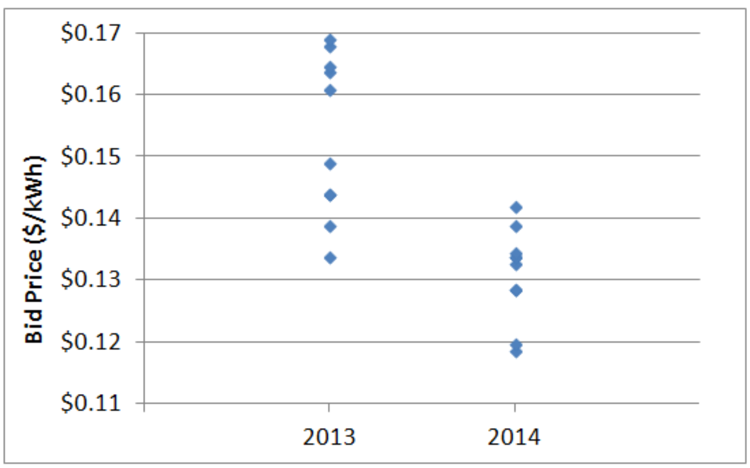
Program. Under the current design, Standard Offer projects are counted toward the SPEED goal of generating 20 percent of 2017 statewide retail electric sales from new renewable resources. Outside of Vermont, the policy interactions are more complicated and not fully resolved. Since Vermont has no binding RPS, RECs produced under the SPEED Standard Offer program are frequently sold to RPS-obligated entities for compliance in other New England RPR markets. Recently, this practice became the subject of CT Docket 15-01-03, initiated to clarify the treatment of RECs associated with the Vermont SPEED resources under the Connecticut RPS and other potential double-counting situations.

2.7.4 Impacts and Observations

Since its launch in 2009, 23 solar PV systems totally approximately 33.9 MW have been commissioned under the Vermont SPEED program. 13 projects (23.4 MW) are currently under review by the PSB, under development or have been issued all necessary permits, but are not yet constructed.

Overall, the program has stimulated some competition in the market. In 2013, 34 proposals representing 60.4 MW were received in response to the 5 MW solicitation. In the most recent round, 18 proposals, totaling approximately 32.75 MW competed for 5 MW of available capacity. All except one of the bids were for solar PV projects. The program has demonstrated that long-term, fixed price, and creditworthy contracts can enable financing and drive down costs. The ten lowest cost bids (all solar) received under the 2014 RFP ranged in price from 11.87 to 14.20 ¢/kWh for 25-year fixed price contracts. This is compared to a bid price range of 13.40 to 16.90 ¢/kWh received under the 2013 RFP. The price cap in both years was 25.7 ¢/kWh.

Figure 12. Ten Lowest Cost Projects (All Solar) Selected Through 2013 and 2014 RFPs



This range of bidding, within a group of only the ten lowest-priced projects, demonstrates the existence of some spread in project costs (or desired returns), that the lowest cost bid and the average bid price are likely to differ, and suggests caution in extrapolating the lowest bid price to a program with larger targets. All else equal, the lowest price in such a shallow market may be difficult to replicate at the larger volumes of projects that would be expected if such an approach were executed Massachusetts. Rather, these bids appear to represent the market's low-hanging fruit, at a diversity of project costs – the lowest of which may or may not ultimately be developable. On the other hand, the authors have observed that multi-round or multi-year competitive processes have often exhibited some price convergence over time, potentially indicators of both the impact of increased competition to reduce prices, the tendency for overly aggressive bidders to leave a market in which profit margins are insufficient, and the tendency for lowest cost businesses to bid towards a market clearing price that becomes better understood over time.

The initial phase of the Standard Offer program demonstrated great success in facilitating market diversity and promoting local job growth. The program supported deployment of a healthy mix of small and large scale projects, pursued mostly by local developers. As the program evolved to a competitive procurement model, smaller systems were no longer able to compete on price with larger installations, especially against national players, who are more sophisticated and can participate at lower costs. Of the seven projects selected in the 2013 and 2014 RFPs, six projects were larger than 2 MW and only two projects are by Vermont-based developers. This trend, combined with infrequent solicitations (i.e. once per year) for relatively small quantities of contracts (between 5 and 10 MW per year, which may translate into only two to five projects per year), is not conducive to driving permanent in-state jobs. The following table demonstrates the difference in project diversity between the original standard offer program and the competitive procurement program to date.

Table 26. Solar PV Project Sizes, Standard Offer Program versus Competitive Procurement Program

	Standard Offer		Competitive Procurement	
Project Size (kW)	Number of Projects	Capacity (kW)	Number of Projects	Capacity (kW)
≤15	5	48	-	-
>15 -100	12	705	-	-
>100 – 250	11	1,753	1	130
>250 – 500	7	2,549	-	-
>500 – 1000	6	5,300	-	-
>1000 – 2000	14	24,954	2	4,000
>2000	13	28,472	4	8,660
Total	68	63,781	7	12,790

Further, the program has also proven that ample challenges exist between submitting an application and executing a contract. Numerous projects have been removed from the list of approved and contracted projects. As of September 2013, 35 percent (22.3 out of 63.8 MW) of the projects initially selected through the Standard Offer program had withdrawn from the queue. Many of these were small or medium-sized systems. A higher percentage of projects have failed than the percentage of MW that have reached service. As shown in Table 27, 56 percent of the projects initially selected through the Standard Offer program have so far failed, while only 22 percent have reached in-service and an equal percentage are still pending. Thus if a similar percentage of pending projects withdraw as have withdrawn to date, the failure percentage could end at approximately 67 percent of total projects.

Table 27. SPEED Standard Offer Project Success Rate (As of September 23, 2014)[52]

Project Size (kW)	Number of Selected Projects	In-Service	Withdrawn	Active
≤15	5	0	5	0
>15 -100	12	6	6	0
>100 – 250	11	1	9	1
>250 – 500	7	0	7	0
>500 – 1000	6	0	3	3

[52] This table does not include projects from the 2013 and 2014 SPEED competitive RFP.

>1000 – 2000	14	4	3	7
>2000	13	4	5	4
Total	68	15	38	15
Percentage	100%	22%	56%	22%

Since the program became competitive, only one project has dropped out so far. This change may be attributable to a combination of reasons. One primary factor is the new $10/kWh proposal security requirement designed to mitigate speculative bidding. Another factor that may lead to higher project success rate is the program's switch to a competitive procurement model, which favors more sophisticated players. However, given that none of the selected projects are currently operational, the project success rate may change in the future. Further, as the procurement volume increases in later years, the effectiveness of the proposal security and the competitive program in impeding attrition may become more apparent.

2.8 Value of Solar Tariffs

2.8.1 Introduction

In the heat of a nation-wide debate regarding cross-subsidization of net metering, the need for a more accurate and transparent method for capturing the value of services provided in each direction (customer to utility and utility to customer) is becoming apparent. Value of Solar Tariffs (VOST) are a rate design approach aimed at exposing the cost and benefits of distributed solar generation, allowing more informed policy and investment decision making. (Fine, Saraf, Kumaraswamy, & Anich, 2014). So far, there are two examples of VOST implementation – in the state of Minnesota and the City of Austin, Texas - both of which operate under a vertically-integrated monopoly market structure.

In 2012, Austin Energy, a publicly-owned utility, became the first U.S. utility to replace net metering with a VOST for residential customers only. The tariff was designed to compensate customers for the value of solar generation they produced in support of the utility's 2020 local solar generation goal of 100 MW (Austin Energy, 2013). The Minnesota legislature enacted Chapter 85 in 2013 with the intent to provide maximum encouragement to distributed generation while protecting ratepayers and the public. The bill directs the state Department of Commerce, in conjunction with the Public Utilities Commission, to establish a methodology for determining the value of solar and authorize the states' public utilities to provide VOST as an alternative option to net metering. (Minn. Statute § 216B.164, Subd. 10, n.d.)

2.8.2 Policy Description

VOST is a rate design approach modeled after, and adapted from, a net metering tariff in structure, but with elements of a standard-offer or feed-in tariff approach. Solar customers enter into long-term value of solar tariffs with distribution utilities to receive compensation for onsite generation. Under both VOSTs and net metering, customers purchase electricity from utilities at retail rates. Unlike traditional net metering, VOSTs do not compensate a solar customer's generation at the retail rate. Instead, the generation is compensated based on a calculated value of solar rate in dollars per kilowatt hour.[53] In this regard, VOSTs are sometimes called a bi-directional rate design as it calculates the value of electricity provided from solar customers to utilities and from utilities to solar customers separately. (Bird, et al., 2013)

The VOST rate is derived from an analysis designed to determine the net benefit associated with distributed solar generation. VOST rates developed to date have been utility-specific. In Austin, the rate was determined by Austin Energy, a city-owned utility. In Minnesota, the state regulator was responsible for creating a methodology for determining the value of solar. Utilities can then apply the methodology to establish a VOST, subject to state approval, as an alternative to net metering. (Minnesota Department of Commerce, n.d.). Typical components to be considered in a VOST calculation include:

- Avoided energy costs
- Transmission and distribution service costs
- Ancillary service costs
- Avoided environmental costs
- Societal benefits (e.g. economic growth and health benefits)

[53] In Minnesota, net excess generation is credited to the customer's next monthly bill for up to twelve months. After twelve months, any unused credits will be eliminated. Austin Energy allows net excess generation to be rolled over to the next year.

VOSTs should be updated on a regular basis to reflect changes in energy costs and other market conditions. Both Austin and Minnesota's VOSTs are subject to annual review. In Minnesota, utilities are required to recalculate the tariff for new systems on an annual basis and file the revised tariff for state approval.[54] Table 289 shows Austin Energy's VOST rates for 2013 and 2014. The rate change was mainly driven by decline in natural gas prices, along with changes in loss savings, transmission savings and assumed project life.

Table 29. Austin Energy Value of Solar Rates

($/kWh)	2013	2014
Value of Solar Rate	$0.128	$0.107

As an alternative to net metering, VOSTs are nominally targeted to residential and small C&I customers that are traditionally eligible for net metering. The Minnesota VOST, for example, has a 1-MW system cap. Austin Energy initially had a system size limit of 20 kW. However, the size cap was eliminated in August 2014, and all residential solar systems are now eligible for the VOST. (Resolution No. 20140828-157, 2014). There are no aggregated program caps in either program.

2.8.3 Key Interactions

As an alternative to traditional net metering, VOST can be implemented with a suite of solar policies that are proven compatible with net metering. On a broader scale, VOST can replace net metering as an additional support for small and medium scale solar projects, while large PV systems continue to rely on RPS, competitive procurements and some tax incentives. All VOST projects can participate in state RPS and solar carveouts.[55] In Austin and Minnesota, there are no provisions that prevent VOST projects from receiving rebates and other direct upfront payments. The interaction between VOST and other performance-based-incentives, such as feed-in tariffs and competitive long-term contracts, is more ambiguous. Depending on whether policymakers view VOST as utility bill offsets or an actual incentive policy, it may affect whether VOST and traditional PBIs are treated as complimentary or mutually exclusive policy options. (Bird, et al., 2013)

Regarding tax incentives, some have expressed concern regarding whether VOST is considered a buy-all, sell-all approach, which could potentially affect system owners' ability to obtain some tax credits that have onsite generation thresholds. Some have argued that VOSTs are a buy-all, sell-all approach as it involves customers paying for all electricity consumption at one rate and being compensated for all generation at a different rate. Other commentators have argued that, like net metering, VOST is an offsetting credit for customer generation, and hence, is not a buy-all, sell-all design. The federal Internal Revenue Service is currently conducting a formal review on the tax implications of VOST.[56]

[54] In Minnesota, the VOST for existing systems is locked-in for the life of the solar PV system. (Fine, Saraf, Kumaraswamy, & Anich, 2014)

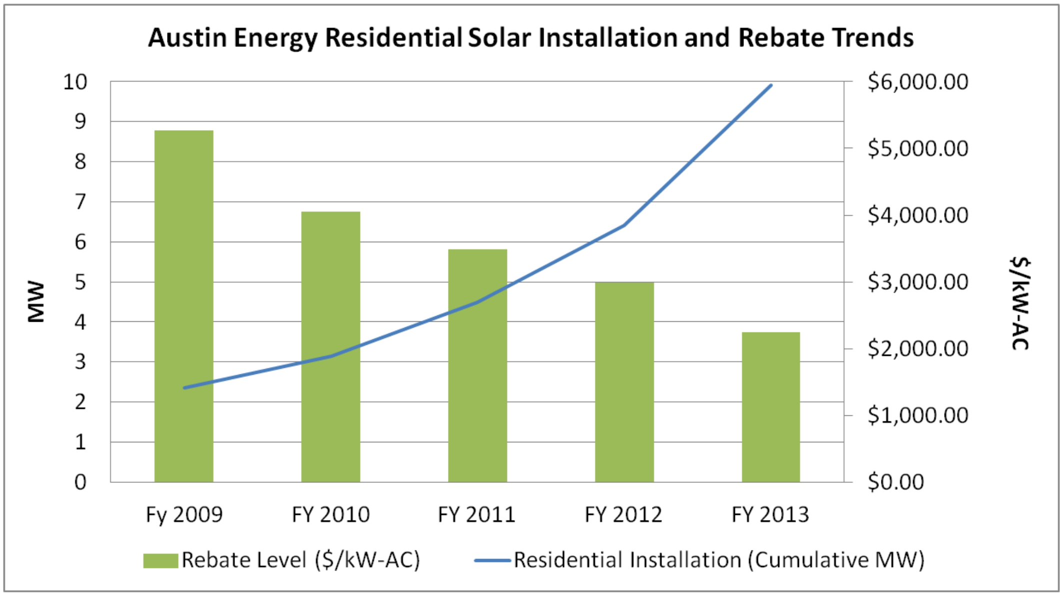
[55] In Minnesota, RECs generated from VOST facilities are owned by public utilities. (Minn. Statute § 216B.164, Subd. 10, n.d.) This requirement is established based on Minnesota's non-competitive market structure and will not apply to VOST in a competitive market, such as Massachusetts.

[56] In August 2013, Skadden, Arps, Slate, Meagher & Flom LLP (the firm) filed a legal memo with the Alliance for Solar Choice regarding the tax implications of feed-in-tariffs and value of solar tariffs. The firm noted that Section 25 D Credits requires 80 percent of the generation to be used onsite. The firm argued that FITs and VOSTs framework require the sales of all customer generation, and hence, could jeopardize a resident's eligibility to receive Section 25 D Credits. (The Solar Alliance for Solar Choice, 2013). At that time, Austin Energy asserted that VOST is an offsetting credit for customer generation, and a sale of all output from customer generators to Austin Energy is not involved. (Bird, et al., 2013). In September 2014, an Austin homeowner filed an Information Letter Request with the federal Internal Revenue Service to address the tax impacts of Austin Energy's VOST. The IRS

2.8.4 Impacts and Observations

VOST can be implemented as a replacement or an alternative to net metering. In Minnesota, utilities are provided with the options to switch to a VOST approach. Since the VOST methodology was established in April 2014, no utilities have yet proposed a VOST with the state. In Austin, where residential VOST is mandated, there is insufficient data to date to draw statistical conclusion on the effectiveness of VOST in Austin. As a result, there is very little industry experience to go on, particularly in locations with modest insolation and competitive markets. However, it is observed that there has been accelerated growth in the market sector, while rebate levels continue to decline since VOST implementation. There have been talks to extend VOST to the commercial sector. (Rabago, 2014)

Figure 13 . Austin Energy Residential Solar Installation and Rebate Trends



will formally review the tax implications of Austin Energy's VOST. At time this section is written, the IRS has yet not issued a decision (The Solar Alliance for Solar Choice, 2014).

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Massachusetts Net Metering and Solar Task Force

Task 2 - Analysis of Solar Development in States without Incentive Policies

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1 Introduction

The U.S. solar market has grown substantially over the past several years, from an estimated 1.2 GW of total capacity in 2009 to nearly 20 GW by the end of 2014 (SEIA, 2015). This market growth has not been uniform across the country, with some states having substantial solar PV generating capacity installed and others having virtually none. The economic viability of PV systems depends on a range of inputs including system installed costs, ongoing operational costs, federal incentives, power production values, and state or utility incentives. The Task Force has expressed an interest in understanding the relationship between state solar programs and actual deployment of solar, and whether it might be reasonable to expect solar development even in the absence of significant state programs. The purpose of this task is to provide a representative analysis of the level of solar development in states that do not have a state-level incentive program (Massachusetts Net Metering Task Force, 2014).

2 Methodology and Analysis

In order to provide a nuanced discussion of the effects of state-level solar incentives on solar market development, this analysis was divided into three components. Since net metering may be a critical component of solar market development, and the Task Force has been asked to provide recommendations to the legislature on the future of net metering in the Commonwealth, this analysis includes a review of solar market development in states that do not have net metering. Additionally, this task reviewed solar market development in states that have similar characteristics to Massachusetts in terms of the economic value of solar production per kilowatt-hour and expected solar system output given state-level solar insolation. Finally, the project team reviewed recently announced large-scale solar installations in states and utility territories that do not have substantial solar incentives. A more detailed review of the analytical approaches and results of each of these tasks is provided below.

2.1 Review of market development in states without solar incentives or net metering

Net metering allows utility customers with on-site distributed generation to offset their electricity usage by exporting excess power to the grid and to receive credit for exported power on their utility bill (Mass DPU, 2015). Net metering rules vary significantly across U.S. jurisdictions with some states and utilities providing full retail value for power exported to the grid while others provide compensation at some fraction of full retail value. To date, 44 states have adopted state-wide net metering in some form. Table 30 below show the U.S. states that have not had state-wide net metering during

State
Idaho
South Dakota
Texas
Tennessee
Alabama
Mississippi
South Carolina

the period of interest in this analysis.[57]

Solar market development has been limited in states without net metering. Table 31 below shows the cumulative solar installations in each of these states as of 2013. As the table shows, Idaho, South Dakota, Alabama, Mississippi and South Carolina all have less than 10 MW of cumulative solar installed as of the end of 2013. Tennessee, which does have solar incentive programs provided through the Tennessee Valley Authority (TVA) and Texas, which has a solar market driven, in part, by municipal utility solar procurements, have more substantial installed capacity than the other states. Massachusetts has been included in Table 31 for reference purposes.

State	2013 Cumulative MW	2013 W/GWh Electricity Sales
Idaho	0.7	29
South Dakota	0.0	0.0
Texas	215.9	587
Tennessee	64.8	675
Alabama	1.9	22
Mississippi	0.3	6
South Carolina	8.0	101
Massachusetts	**445.0**	**8,167**

Given the significant diversity of states in this analysis, cumulative state solar capacity has been normalized in Table 2 to account for the size of the state's total power consumption. Total state solar capacity in 2013 in watts was divided by the total state electricity sales in GWh. This provides a better comparison between states without net metering and Massachusetts. As this comparison shows, the normalized cumulative PV watts per GWh of electricity sales shows that the Massachusetts solar market is an order of magnitude larger than any solar market without net metering, suggesting that net metering is a critical component to solar market development.

2.2 Review of market development in states with net metering, but modest solar incentives

Numerous states have implemented diverse programs in addition to net metering in an effort to encourage the development of solar markets. These efforts range from modest benefits such as reductions in sales and property taxes to more lucrative incentives such as rebates and performance based incentives. Analyzing the effect of state-level incentive policies on solar market development is key to understanding if and how Massachusetts' solar market could evolve in the absence of state-level solar incentives. While future market dynamics would be highly dependent on a number of state-specific factors and future solar installed costs, evaluating the solar market development in states that are similar to Massachusetts but lack major solar incentives does provide an indicator of potential market dynamics in the absence of state-level incentive support.

Solar PV system economics are influenced by several state-specific factors beyond incentives, most notably the potential production of the system (i.e., the solar resource in the state) and the retail value

[57] In December 2014, South Carolina's Public Utilities Commission received a settlement agreement for a statewide net metering program, but this has not yet been approved and the policy has not been implemented.

of each kWh produced by that system. The combination of these two factors provides a proxy for the potential value of PV systems excluding state and federal incentives in each state.

In order to conduct a comparative analysis of state-level solar market development that is most relevant to the Massachusetts context, the project team identified 19 states that have a similar combination of retail electricity prices and solar resources to Massachusetts. This was done by calculating the expected value of power produced by a 1 kW system in each state by multiplying the expected production a PV system in that state by the average retail value of power.[58,59]

$$Annual\ \$\ per\ kW$$
$$= 8760\ Hours\ Per\ Year\ X\ State\ Average\ Capacity\ Factor\ X\ Average\ Retail\ Power\ Price$$

This calculation resulted in a hypothetical value for the power generated by a 1 kW PV system in each state in the absence of state-level incentives. States with low solar resource, but high retail power values, may have expected power production values that are similar to that in states with high solar resources, but low retail power prices. To illustrate this phenomenon, example calculations are provided below for Vermont and Nevada--two states with very different solar resources and retail power prices, but similar expected PV system expected production values.

$$Nevada\ \$\ per\ kW\ per\ year = 8760\ X\ 0.186\ X\ \$0.0958\ = \$\ 155$$

$$Vermont\ \$\ per\ kW\ per\ year = 8760\ X\ 0.129\ X\ \$0.1327\ = \$\ 149$$

Table 32 shows the 19 states where the combination of state-level solar resource and state-level retail power value most closely aligns with Massachusetts.

Table 32. Average Annual Retail Electricity Value from a 1 kW PV system[60]

State	$/kW	State	$/kW
CA	$206	MD	$158
CT	$204	NV	$155
NY	$184	VT	$149
NJ	$181	ME	$147
MA	**$172**	NM	$144
NH	$169	FL	$144
RI	$169	CO	$139
DE	$165	TX	$135

[58] The retail value of power used in this analysis was based on the average state-wide retail power price for all customers in the state between 2008 and 2012 (EIA, 2015). While different customer classes may pay substantially different retail rates within a state and even within separate utility territories, for the purposes of this analysis, state-level average power prices provide an adequate proxy for more granular power price data.

[59] The average state-wide solar PV capacity factor was based on National Renewable Energy Laboratory data. PV systems within a state will have highly variable production profiles based on site-specific factors such as orientation and system shading, however state-level capacity factor estimates provide a reasonable estimation of system production and are adequate for the purposes of this analysis.

[60] Hawaii, with high retail electricity costs and relatively high solar insolation, had an average annual retail electricity value from a 1kW PV system of $418, making it a significant outlier.

DC	$163	GA	$134
AZ	$162	KS	$120

As the table shows, the expected value of PV system production in many northeast states, with their relatively high retail power prices, is higher than that in many states in the south and southwest that have greater solar resources but lower retail power values. The 19 states identified as having the most similarity to Massachusetts with respect to the combination of solar resource and retail power prices were further examined to determine how state solar market development differed between states with major solar incentives and those without.

For the 19 states identified as having the most similar non-incentive solar market condition (i.e., the combination of solar insolation and retail electricity prices), the project team reviewed available state-level solar incentives. Solar incentives in each of the analyzed states were classified as major or minor based on a qualitative review of the incentive type, incentive value and volume of available incentives. For example, some states have renewable energy incentives available, but do not have incentives specifically reserved for solar. These states would be classified as having minor solar incentives. Conversely, some states have created specific solar or distributed generation [DG] targets as part of their renewable portfolio standard. These states would be classified as having major solar incentive programs.

Data on 2013 cumulative solar capacity for each of the 19 states of interest were normalized based on total retail electricity sales in order to compare solar market activity in states of dissimilar sizes. This was accomplished by dividing the cumulative state solar capacity in 2013 by the total retail electric sales in that year (EIA, 2015; Sherwood, 2014). Additionally, 2013 RPS solar (or DG) targets were researched (DSIRE, 2015). For some states with major incentive programs, explicit annual solar goals were not available while in others, solar targets were an explicit part of the RPS policy. Table 33 below shows both the 2013 solar/DG targets along with the 2013 adjusted solar market capacity in solar watts per GWh of sales.

Table 33. State Solar Market Incentives and 2013 Metrics

State	Major/Minor Incentive	Major Incentive	State 2013 DG/Solar Goal	Annual Solar Value w/o Incentives	2013 W/GWh
AZ	Major	State RPS that includes DG carve out	1.20%	$162	20,651
CA	Major	Utility-supported rebate and long-term contracting programs as part of RPS	Major incentive; no %age target	$206	20,171
NJ	Major	SREC obligation as part of state RPS	0.80%	$181	15,921
NV	Major	Energy portfolio standard with solar carve-out	0.90%	$155	12,070
NM	Major	RPS with solar carve out	2.00%	$144	11,068
MA	Major	**SREC obligation as part of state RPS**	0.38%	$172	8,167
VT	Major	Solar-specific long-term contracting program	Major incentive; no %age target	$149	7,460
CO	Major	State DG carve out in RPS	1.25%	$139	6,690
DE	Major	SREC obligation in state RPS	0.40%	$165	5,590
MD	Major	SREC obligation in state RPS	0.25%	$159	2,833

CT	Major	Utility-supported ZREC programs	Major incentive; no %age target	$204	2,596
NY	Major	NYSERDA supported rebates and long-term contracting through RPS	0.34%	$184	1,677
DC	Major	SREC obligation in district RPS	0.50%	$163	1,488
RI	Major	Utility-supported long-term contracting program, recently increased targets	Major incentive; no %age target	$169	976
NH	Minor	State has RPS solar carve out, however credit price caps are not differentiated from other renewable technologies	0.20%	$169	873
GA	Minor	Limited utility-based programs	0.00%	$134	835
FL	Minor	Limited utility-based rebate programs	0.00%	$144	620
TX	Minor	No major state-wide solar incentive; some utility-specific programs and contracts	0.00%	$135	587
ME	Minor	No major solar incentives	0.00%	$147	448
KS	Minor	No major solar incentives	0.00%	$120	28

In order to determine whether state-wide solar policies--and therefore incentives resulting from those policies--or non-incentive factors such as in-state solar resource and retail power prices were major drivers of market development, scatter plots were developed that graphed market penetration against average non-incentive solar system annual value as well as market penetration against state-wide solar goal. These graphs are shown in Figure 14 and **Error! Reference source not found.**.

Figure 14. Adjusted 2013 PV Market Capacity vs. Average Annual Solar Non-Incentive Value

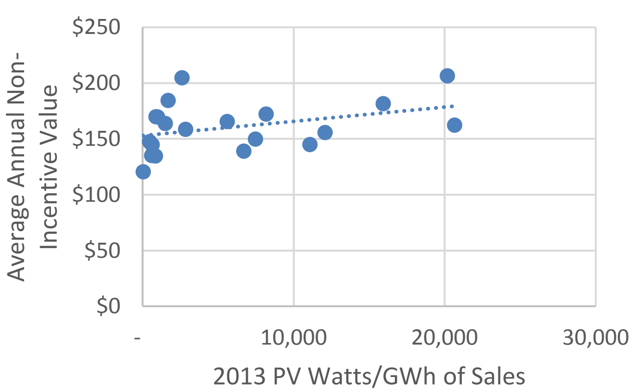
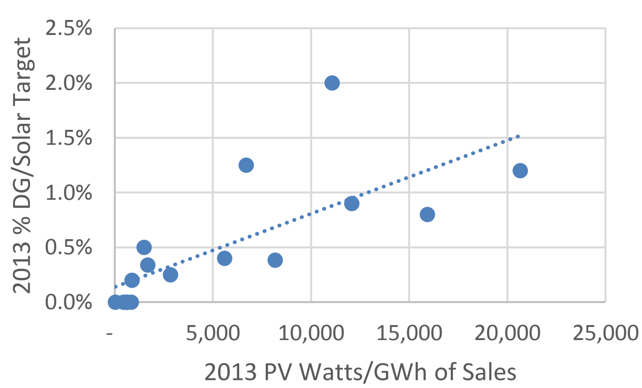


Figure 15. Adjusted 2013 PV Market Capacity vs. 2013 State RPS Solar/DG Target



As the figures show, non-incentive annual solar value had limited relationship to total solar market penetration in the states analyzed, while state-wide solar goals had a more robust linear relationship to solar market penetration. As would be expected, states with more significant solar goals in 2013 had more in-state solar capacity than states with smaller or non-existent solar goals. This result suggests that, during the period reviewed and for the states analyzed, state-level policies in the form of solar RPS targets (and the various forms of incentives that result from those policies) were the primary driver of solar market development and that states that have substantial solar potential, but did not have incentive policies, had not developed significant solar markets.

2.3 Discussion of select recent publicly announced utility scale solar projects

The results in the previous two sections relied on data from 2013, the most recently available state solar installation dataset. During the past year, several utilities have announced large-scale solar projects in states without significant solar incentives. These announcements have frequently promoted that the long-term contract prices associated with these installations are competitive with traditional fossil power sources. Beyond these announcements, little public data is available about the overall costs of these systems, the incentives they may be monetizing, and other contract details. Recently announced systems include a 150 MW 25-year power purchase agreement between Austin Energy and Recurrent Energy for below $0.05 per kWh (Wesoff, 2014), more than 320 MW of solar in Utah qualified under an avoided cost program through Rocky Mountain Power (First Wind, 2014), and a 10 MW PV system in Kentucky that was approved by regulators as a hedge against future national carbon regulations (Tincher, 2014). These and other recently announced projects in states that do not have robust solar incentive programs are indicative of the improving economics of solar. That said, the context for these installations is significantly different from the current Massachusetts market, particularly with respect to installation size. Solar PV systems benefit from significant economies of scale and the recently announced low-cost solar power contracts have been in locations where very large, utility-scale solar arrays are viable.

3 Conclusion

As the analysis in this section shows, historical solar market development has been largely dependent on state-level policies in the United States. States that do not offer net metering have historically had highly limited solar market development compared to Massachusetts. Additionally, state-level targets and incentives have been a major driver of solar market development to date. As the analysis in this section shows, states that have not had robust solar incentives and targets, but have adequate solar potential, have seen limited market growth compared to similar states with solar incentives and binding targets. This suggests that, for the time being, state-level solar policies may be critical to future solar market growth in the U.S. Finally, a number of utility-scale PV systems have been recently announced in states without major incentives. These systems have purportedly signed contracts at prices competitive with fossil fuel generators. While these systems are very large and are able to capture significant economies of scale, unlike systems currently installed in the Massachusetts market, they do point to a potential future under which solar PV is less dependent of state-level incentives.

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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 hypothetical) 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.

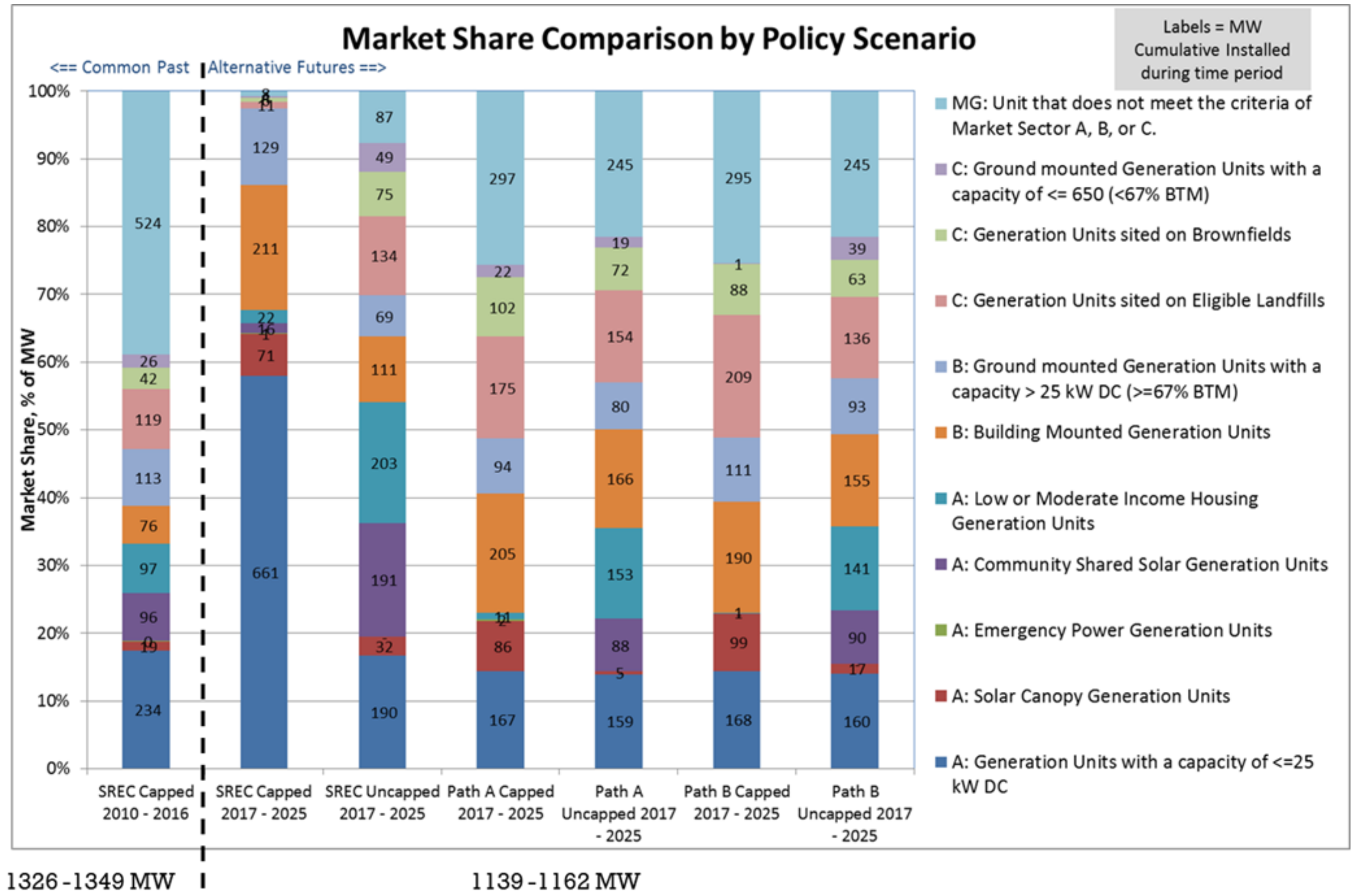
Costs and Benefits: The 25-year net costs to non-participating ratepayers and net benefits to Massachusetts citizens at large associated with Path B are elevated somewhat relative to Path A, but are both lower on net relative to the SREC Policy baseline. The net benefits accruing to non-owner participants 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 16 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 16: Subsector Market Share Comparison by Policy Scenario



Quantified Costs and Benefit Results

Table 34 and Table 35 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 34: 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 35: 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."[61] 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.[62]

- **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').[63]

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- **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 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.

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[61] 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)

[62] 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).

[63] 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.

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* <u>*relative*</u> *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.*[64]

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.[65]

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 <u>and non-participating ratepayers</u>.

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 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-

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[64] Net Metering Task Force Framing Memorandum.

[65] 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.

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 36 below describes the types of individuals and businesses that are both solar customer-generators and non-owner participants.

Table 36: Summary of Four Perspectives

<table>
<tr><th colspan="2">Participants</th><th rowspan="2">NPR: Non-participating Ratepayers

(within MA)</th><th rowspan="2">C@L: Citizens of MA at Large</th></tr>
<tr><th>NOP:

Non-Owner Participants</th><th>GC:

Customer-generators

(Including Host- and 3rd-Party (3PO) System Owners)</th></tr>
<tr><td>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)</td><td>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.</td><td>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.</td><td><u>Sum</u> 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.</td></tr>
</table>

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.[66]
- **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.

[66] 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.

- 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[67], it was not further subjected to the full benefits and costs analysis.

These futures are summarizes in **Table 37**, and described further through the remainder of this section.

[67] 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 37: 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 37***:***

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.[68] 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.[69]

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***

[68] 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.

[69] 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.

(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 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 38 and Table 39 respectively.

Table 38: 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 39: 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 40. These definitions were selected by the Task Force as a convenience, and were not meant to preclude alternative segmentation choices.

Table 40: 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 41. 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 41: 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.[70] 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.[71]

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

[70] 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.

[71] 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.

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.[72] As with the small component of Policy Path A, the program is offered to systems 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

[72] 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.

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.[73] 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 17 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 18 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 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, MA.

Figure 17: Illustrative Impact of MA Distributed Solar on MA Distribution Company Peak Day, in 2014 and 2025

[73] 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.

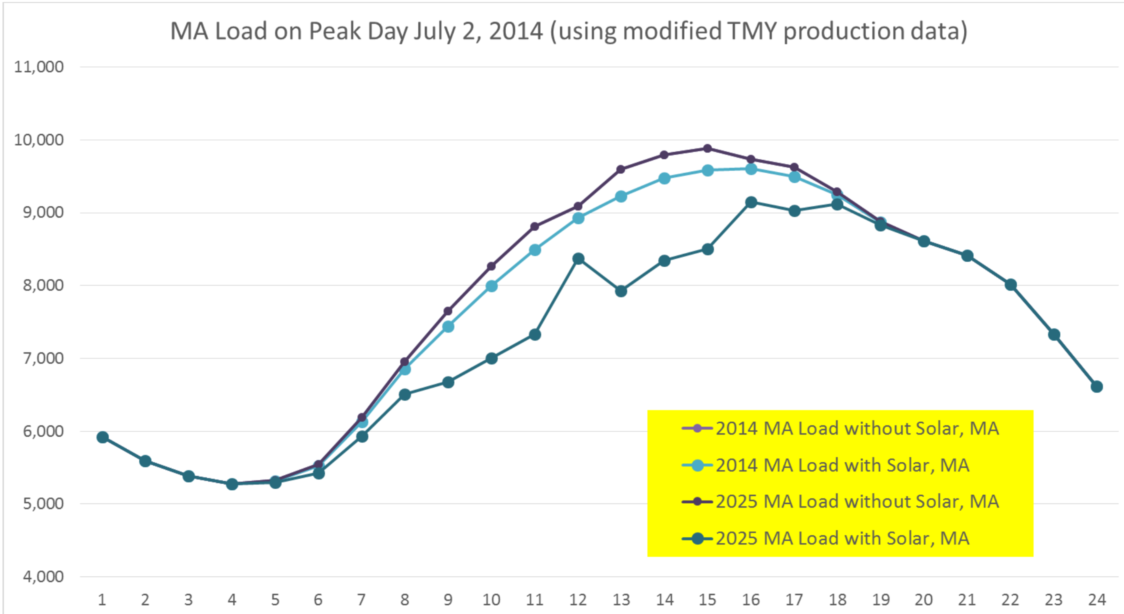
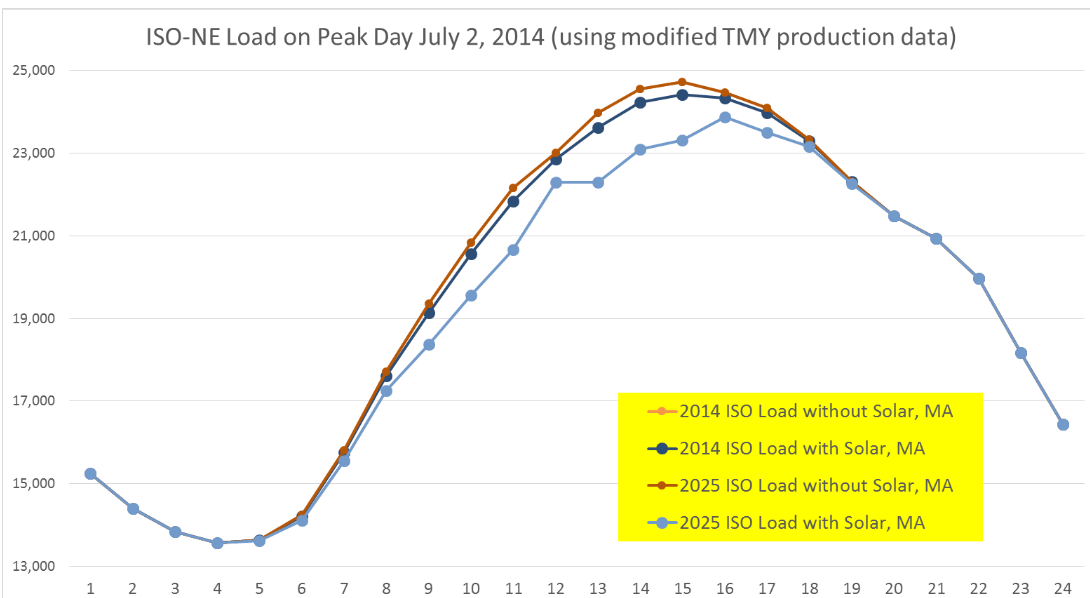


Figure 18: Illustrative Impact of MA Distributed Solar on ISO-NE System Peak Day, in 2014 and 2025



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

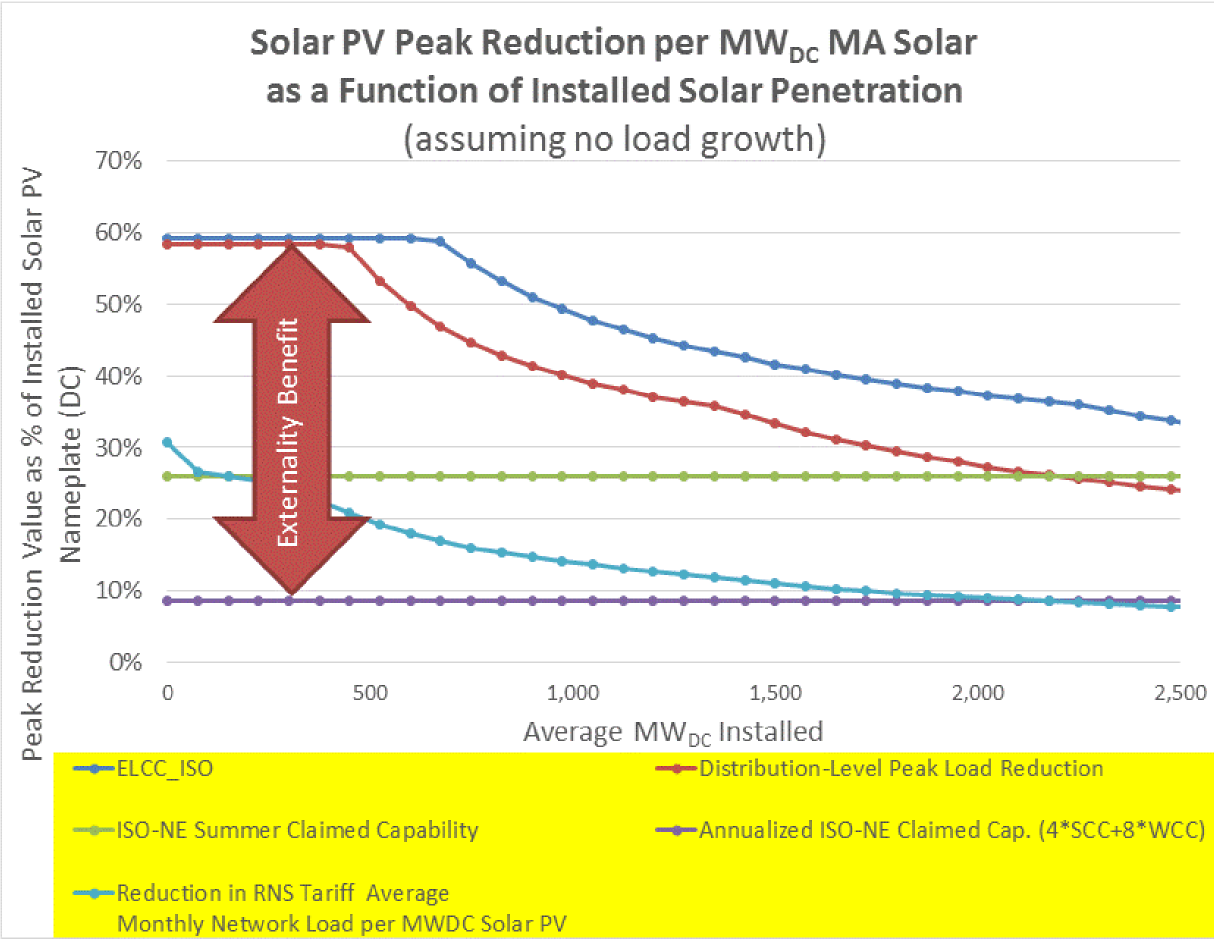
- ELCC_ISO: System generation (i.e. the impact on installed capacity reserves) and transmission peaks
- Massachusetts Distribution-Level Peak Reduction
- The calculated impact on Regional Network Service (RNS) tariff monthly peak loads
- The FCM Summer Claimed Capability (SCC)
- The FCM Weighted Average 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 19. 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")[74].

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.

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

Figure 19: 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 19 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[75], 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 42. The average and peak loss data by utility used to calculate these statewide loss factors is found in Appendix A.

Table 42: Statewide Weighted Average MA DG Solar Avoided Electric Loss Factors

Loss Level	Loss Factor

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

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 43 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 43: 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 43 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 44 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 44: 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 Appendix D: Components of Cost/Benefit Analysis for a detailed description of each subcategory.

Table 45 below illustrates how these subcategories accrue as direct costs or benefits to the four perspectives analyzed.

Table 45: 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 Appendix D: 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 46: 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 Appendix D: 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 47: BTM Production within the Billing Month Applicability to Analysis Perspectives

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

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 Appendix D: 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 48: 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 Appendix D: 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 49: 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	- Wholesale Market Impacts – Energy - Wholesale Market Impacts – Capacity [1] - Avoided Generation Capacity Costs (and Avoided	- N/A

(CC@L)	Capacity Reserves) - Avoided Line Losses - Avoided Transmission Tariff Charges [1]	
[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 Appendix D: 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 50: Electric Investment Impacts Applicability to Analysis Perspectives

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

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 Appendix D: 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 51: 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.

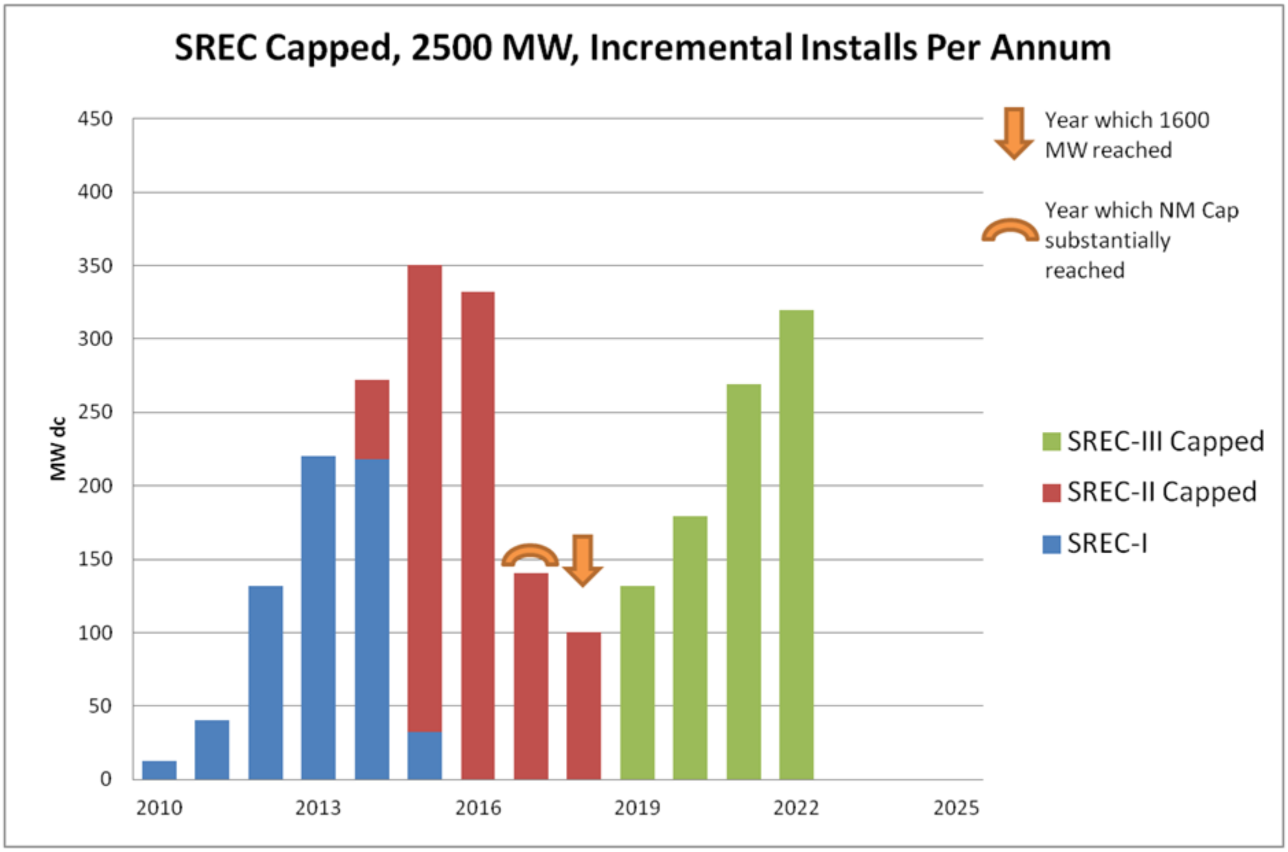
5.1 Comparing Solar Build-out Trajectories

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 20, 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.

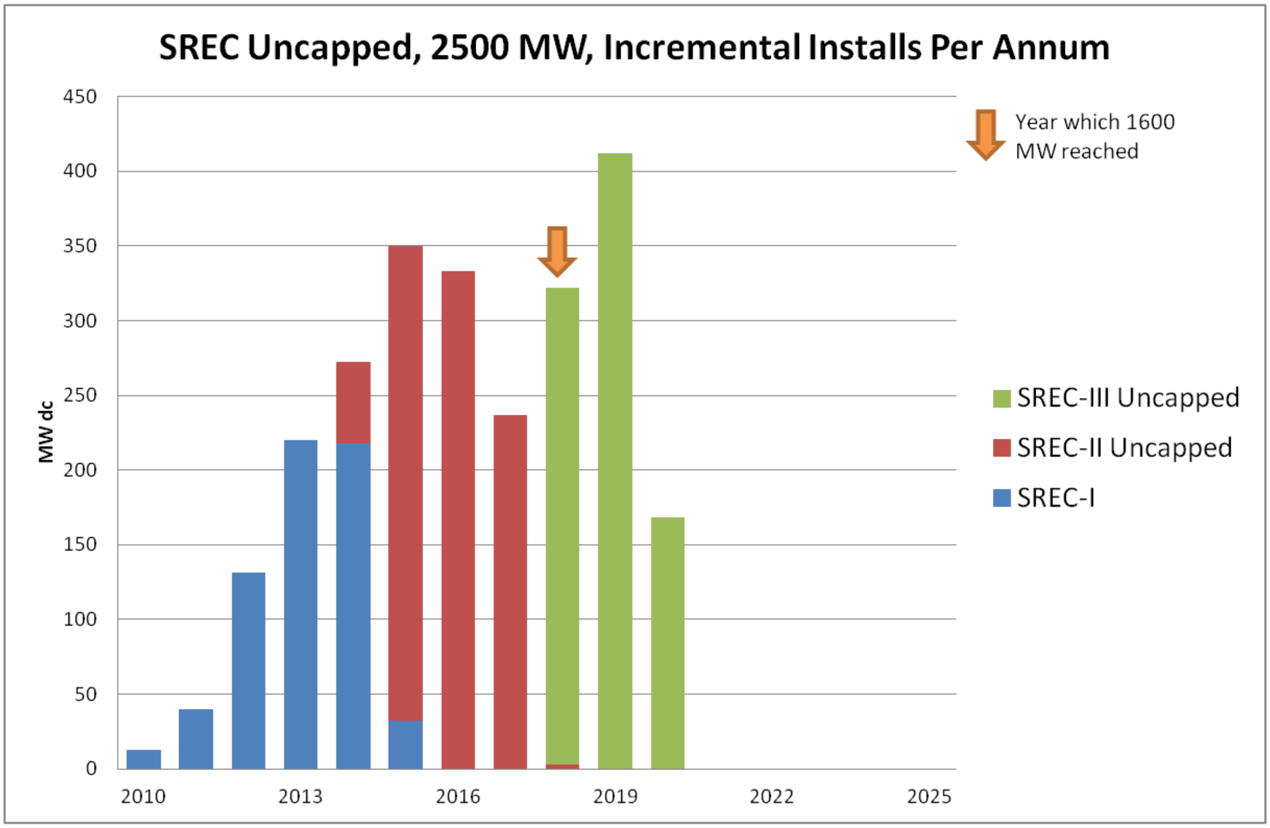
Figure 20: SREC Capped to 2500 MW Incremental Installations per Year by Program



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 21).

Figure 21: SREC Uncapped to 2500 MW Incremental Installations per Year by Program



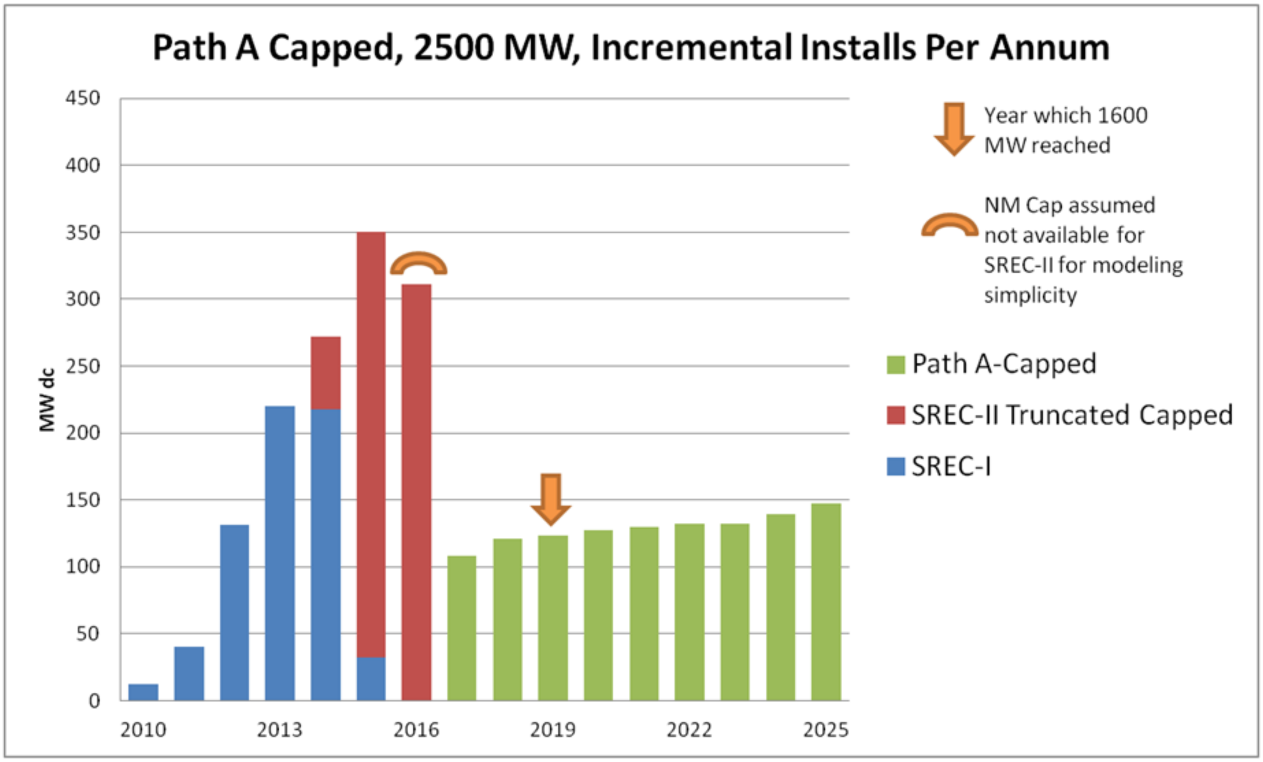
As noted earlier, the SREC policy continued to 2500 MW is not modeled further for benefits and costs, as it reaches 2500 MW so quickly as to not provide a useful point of comparison to other policy futures, and because it led to a number of other complicating factors from a modeling perspective.

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[76]. 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 22).

[76] 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.

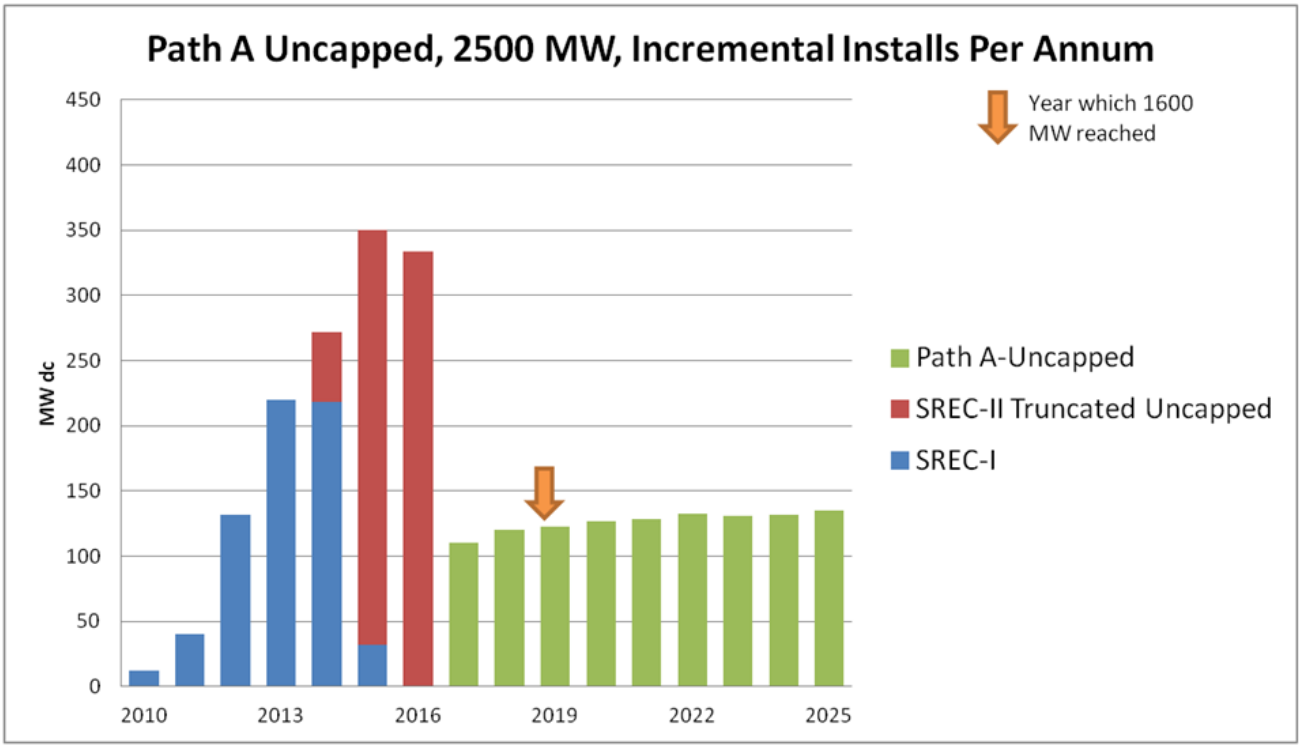
Figure 22: Policy A Capped to 2500 MW Incremental Installations per Year by Program



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.

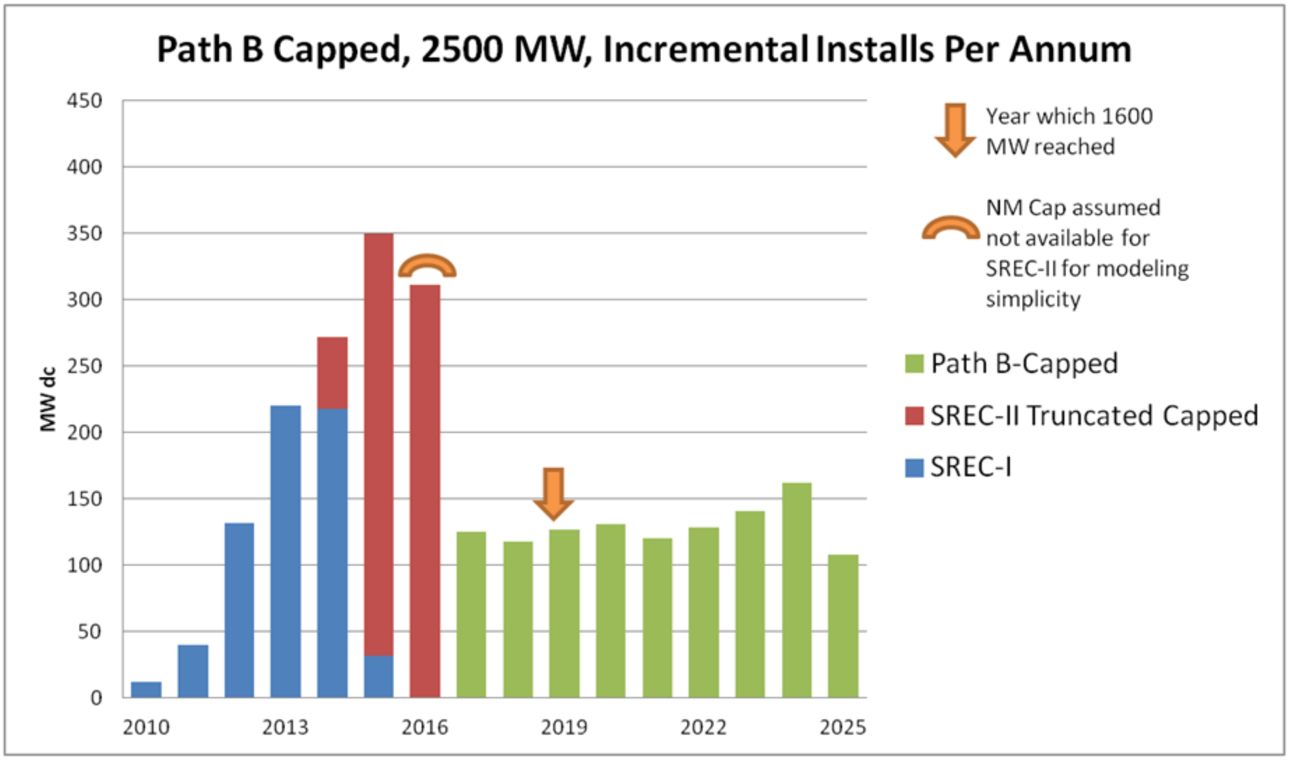
Figure 23: Policy A Uncapped to 2500 MW Incremental Installations per Year by Program



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.

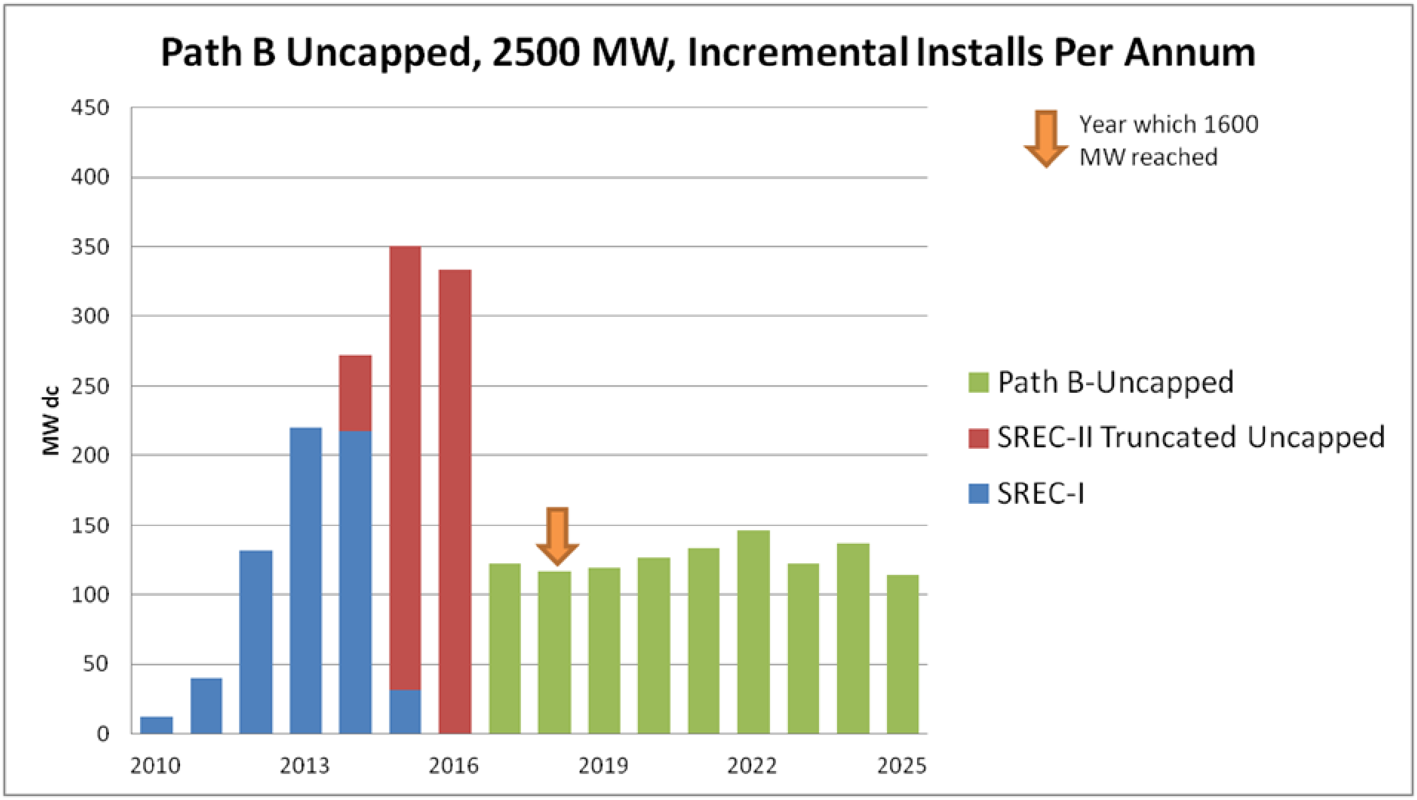
Figure 24: Policy B Capped to 2500 MW Incremental Installations per Year by Program



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

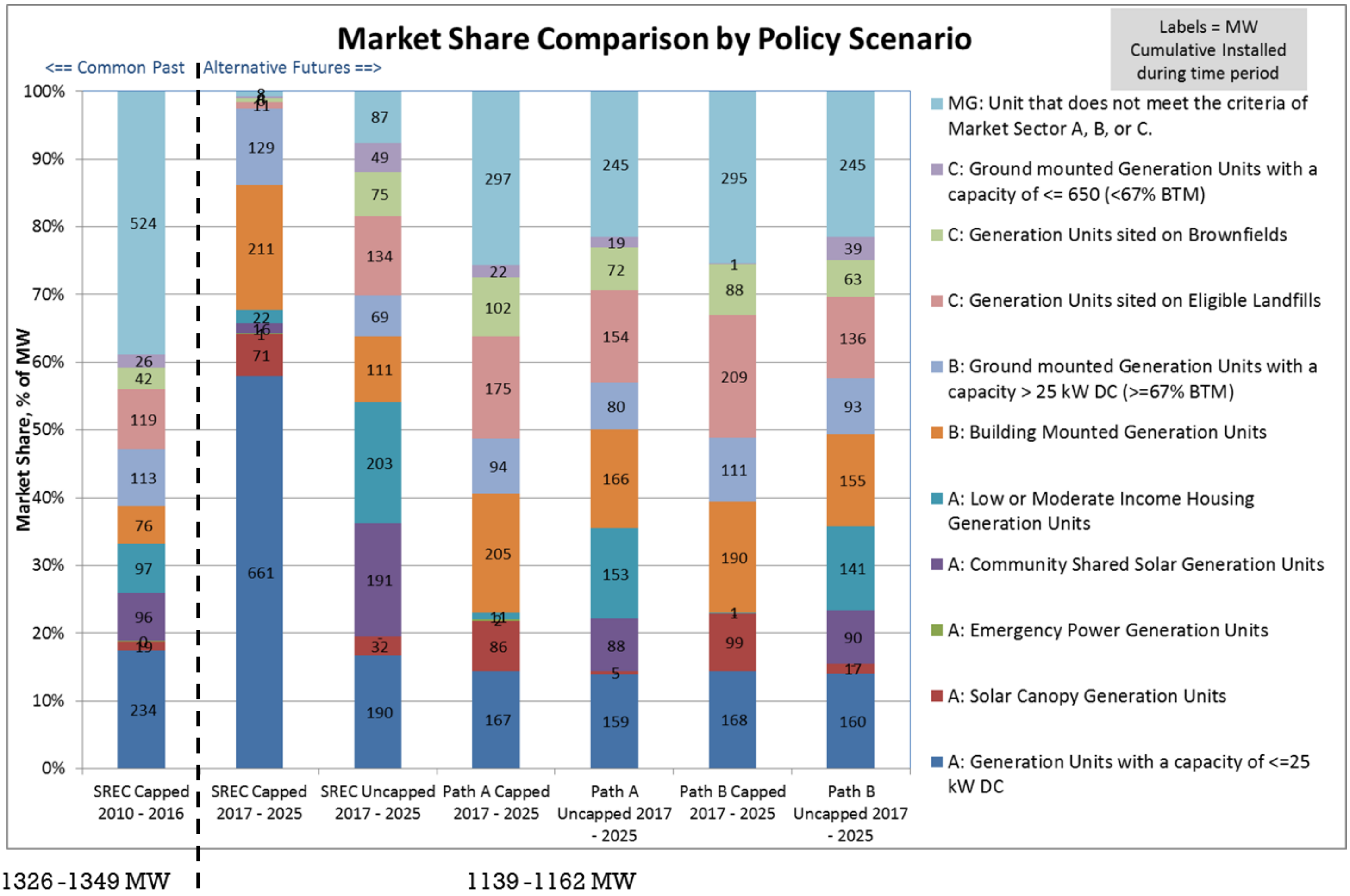


5.2 Solar Build-Out Market Share Projections by SREC-II Market Sector

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 26, 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 26: 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 28: SREC Capped Subsector Market Share Comparison Before and After 2017Figure 28 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 27: SREC Capped to 2500 MW Incremental Installations per Year

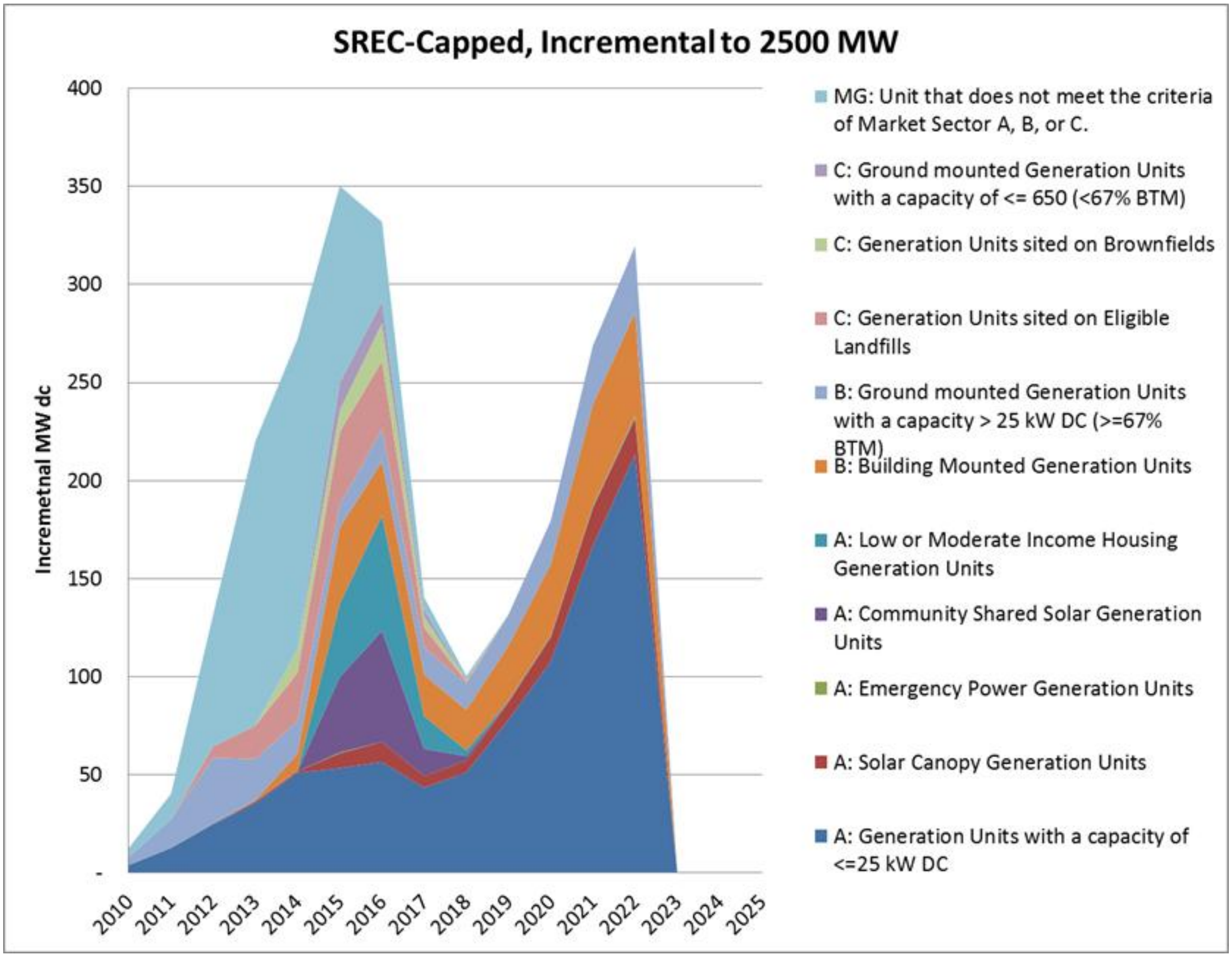


Figure 28: SREC Capped Subsector Market Share Comparison Before and After 2017

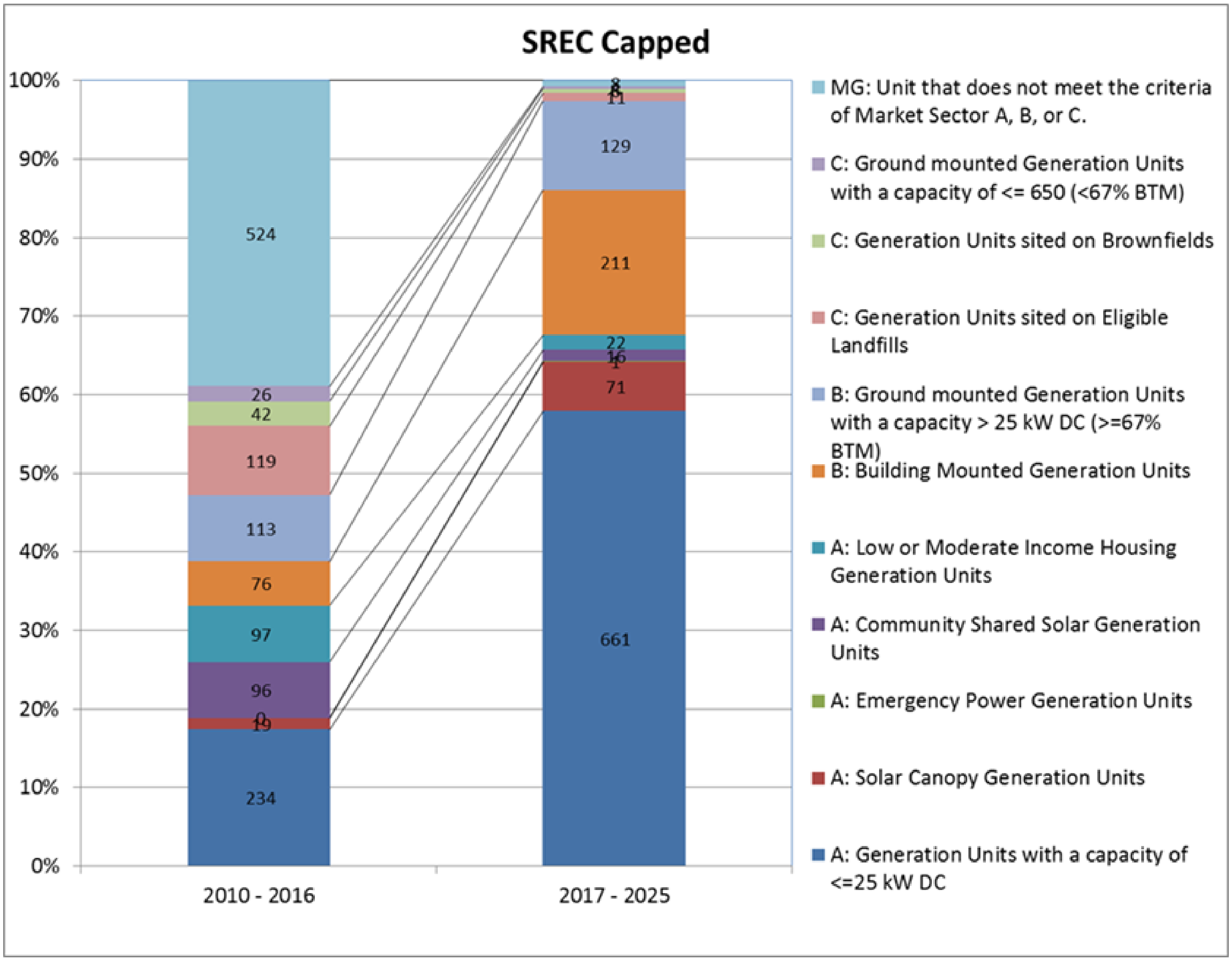


Figure 28 underscores that the dramatic market share growth in small and Building Mounted subsectors comes at the expense of MG projects, CSS, VNM LIH, landfill, brownfield and other ground-mounted systems who lose the ability of net metering.

5.2.2 SREC Policy Future – Uncapped

As can be seen in Figure 29, 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 30 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 29: SREC Uncapped to 2500 MW Incremental Installations per Year

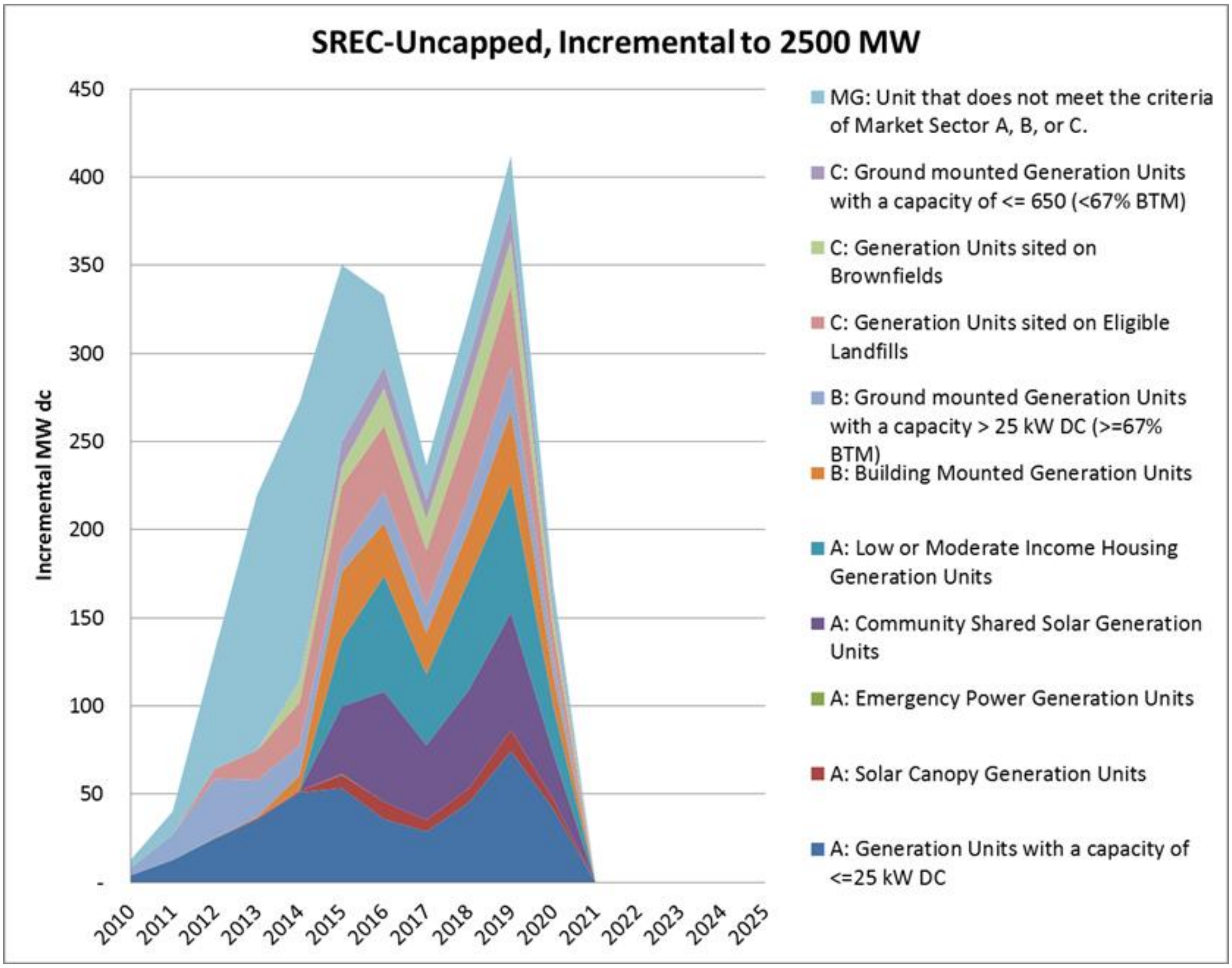
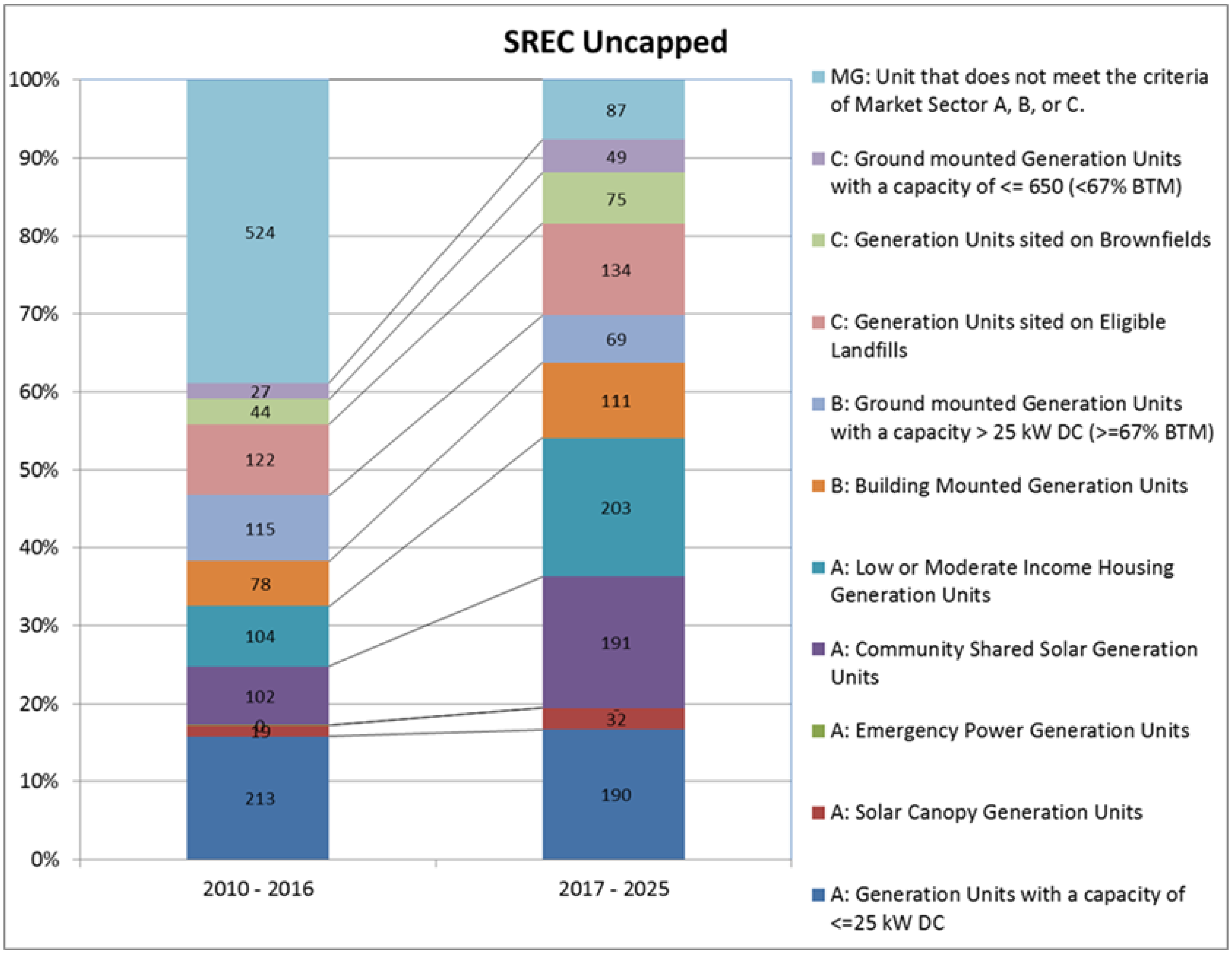


Figure 30: SREC Uncapped Subsector Market Share Comparison Before and After 2017



5.2.3 Policy Path A – Capped

As shown in Figure 31, 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.[77] 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 scenarios, with the loss of net metering, there is an increase in on-site load dependent projects like Building Mounted and Solar Canopy.

[77] 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.

Figure 31: Policy A Capped to 2500 MW Incremental Installations per Year

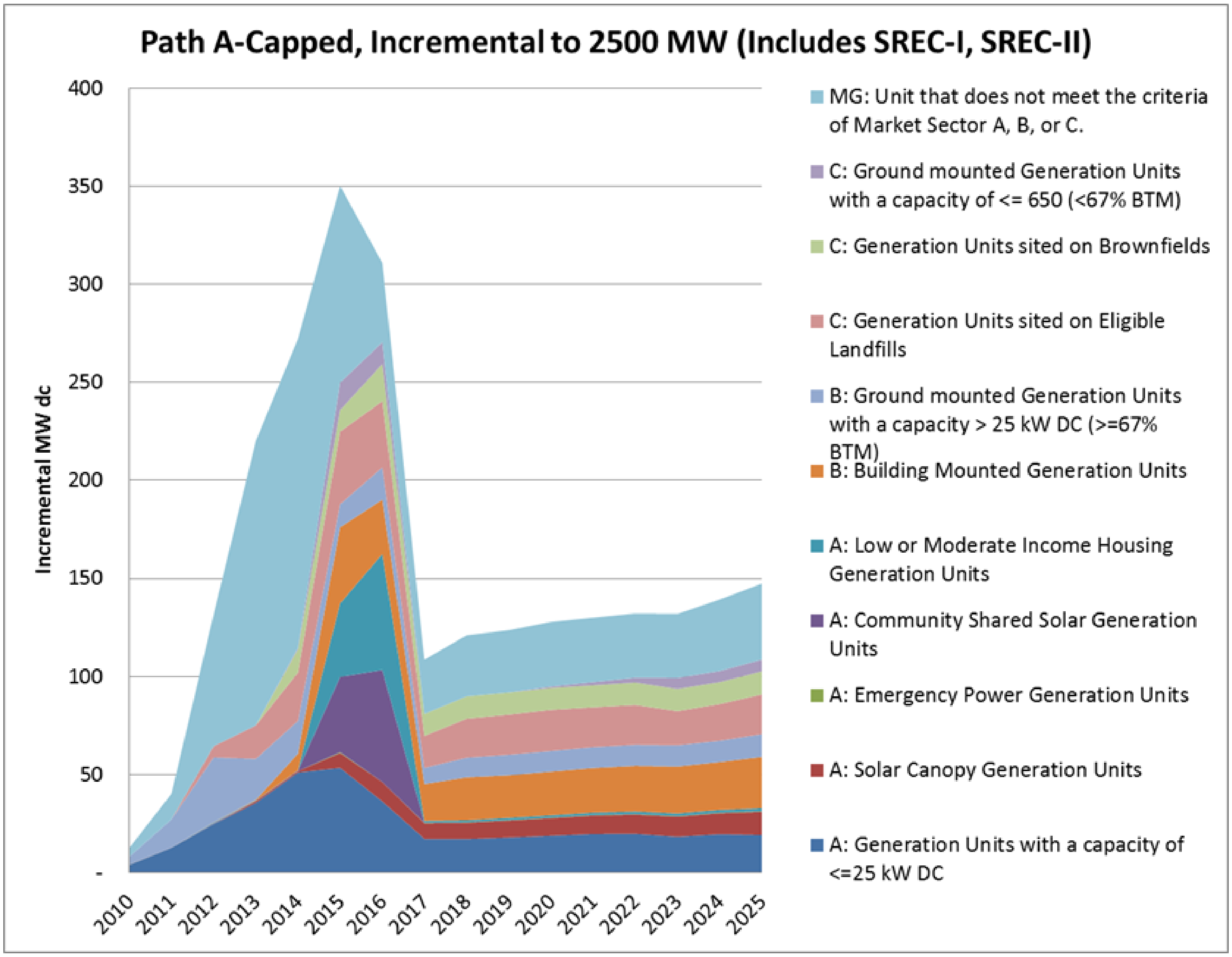
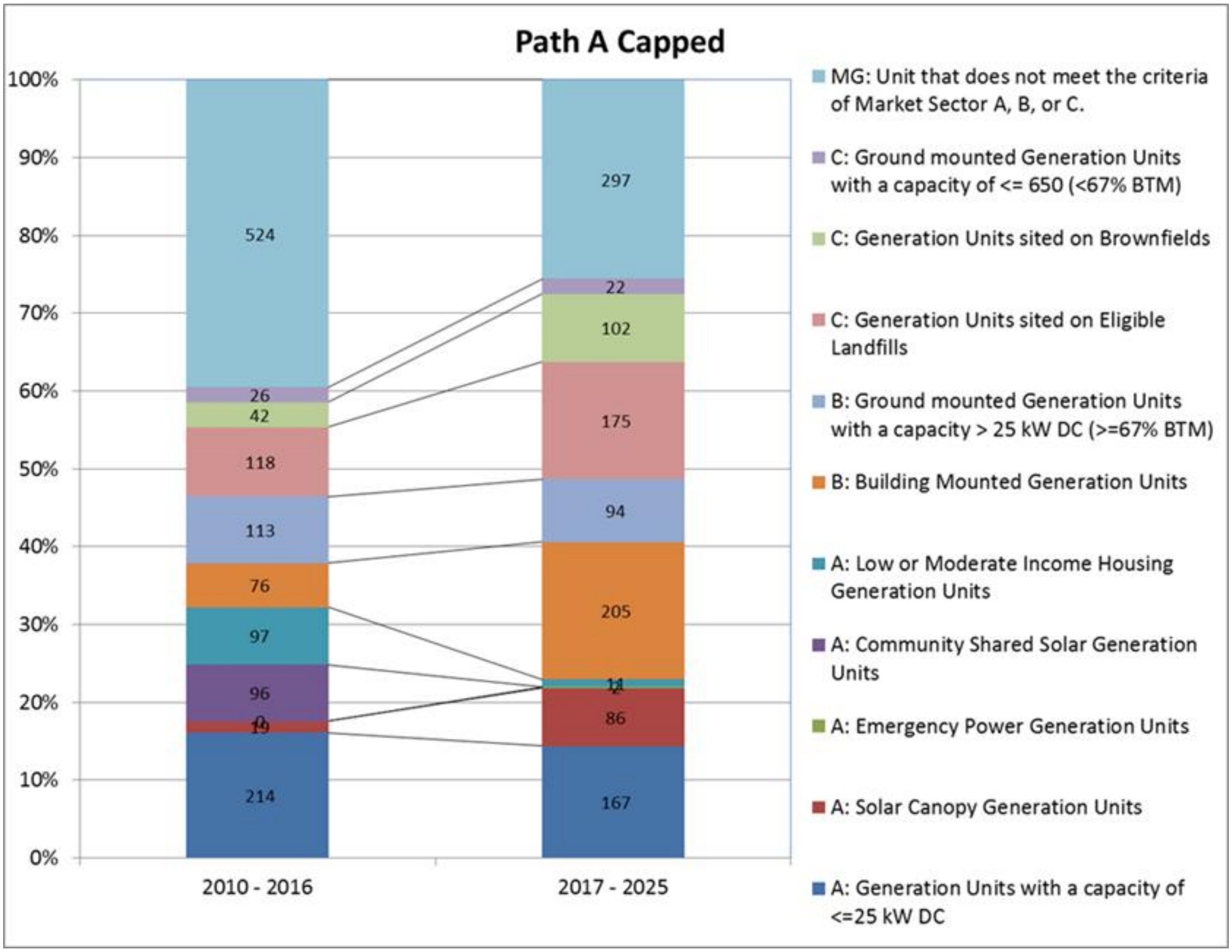


Figure 32: Policy A Capped Subsector Market Share Comparison Before and After 2017



5.2.4 Policy Path A – Uncapped

Under the Policy A uncapped future, Figure 33 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 33: Policy A Uncapped to 2500 MW Incremental Installations per Year

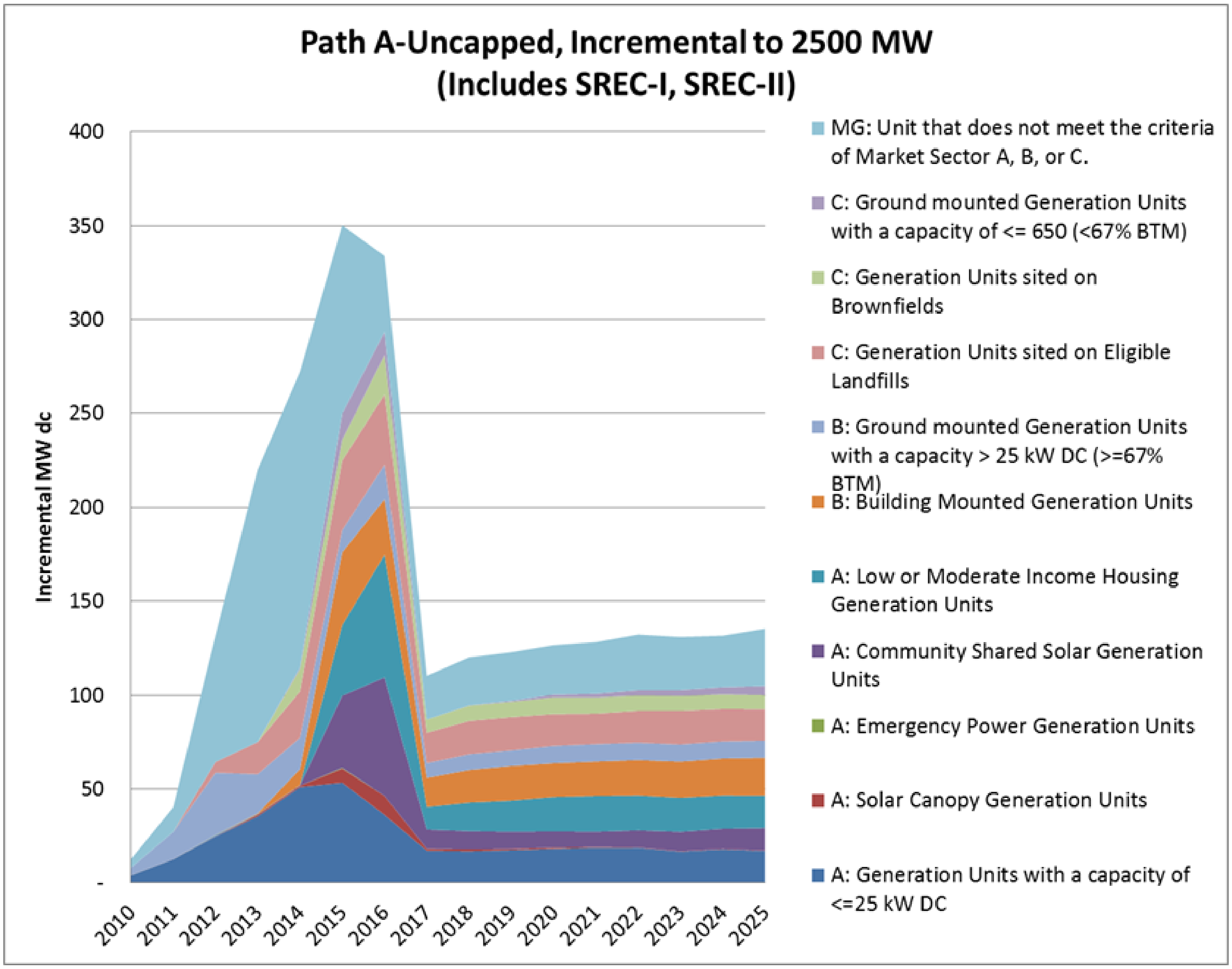
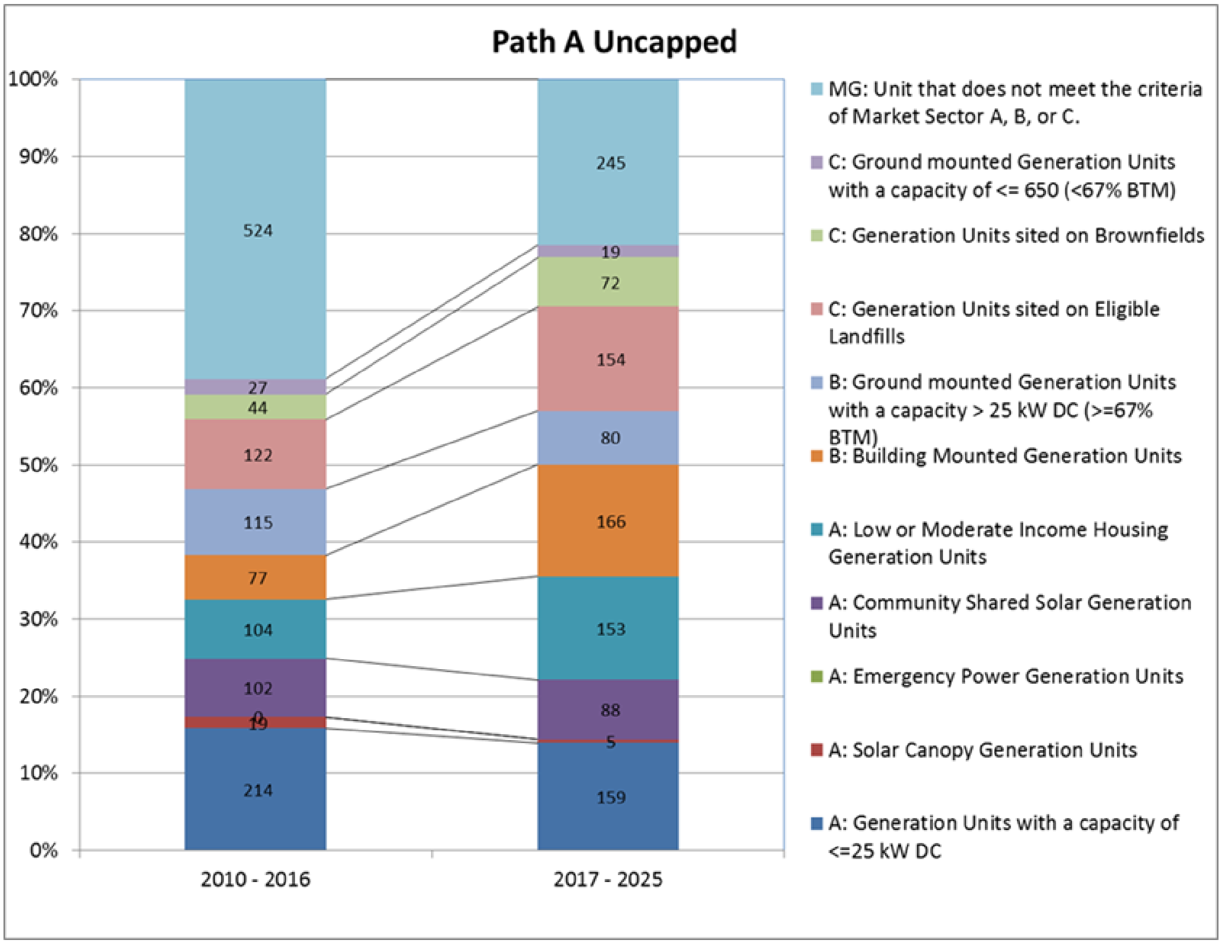


Figure 34: Policy A Uncapped Subsector Market Share Comparison Before and After 2017



5.2.5 Policy Path B – Capped

As shown in Figure 35, 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 35: Policy B Capped to 2500 MW Incremental Installations per Year

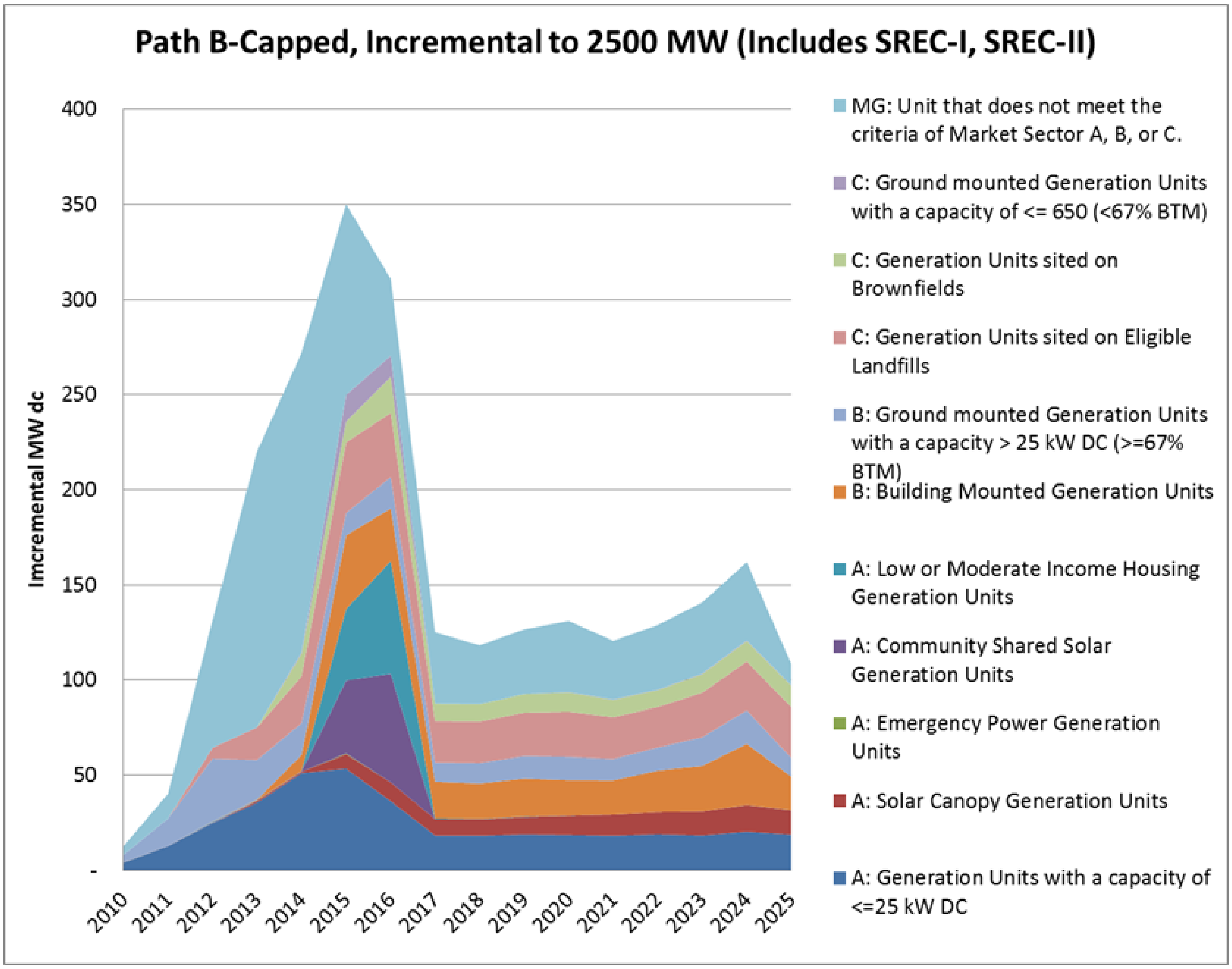
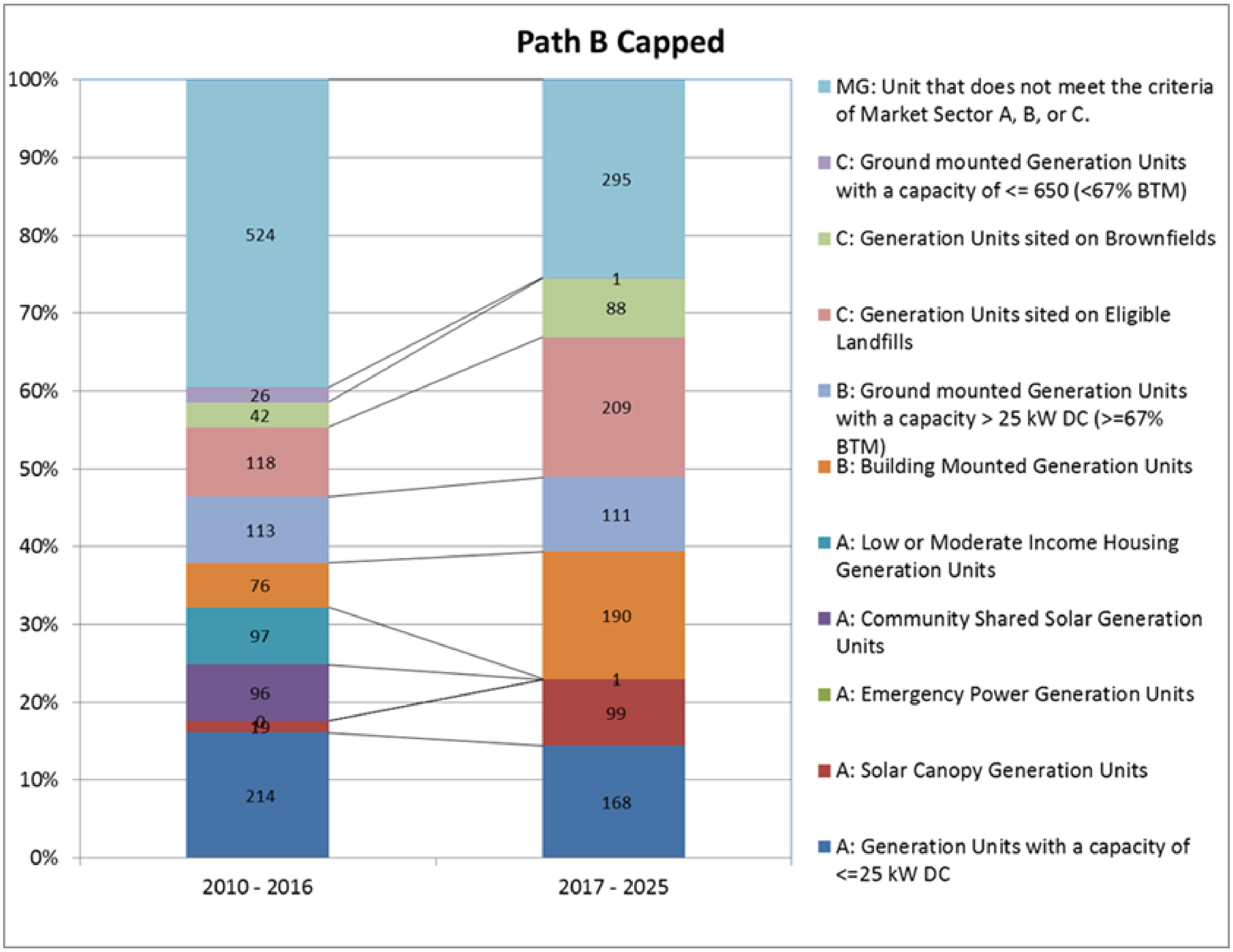


Figure 36: Policy B Capped Subsector Market Share Comparison Before and After 2017



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 38 shows that VNM LIH and CSS cumulative installations increase after SREC-II is truncated.

Figure 37: Policy B Uncapped to 2500 MW Incremental Installations per Year

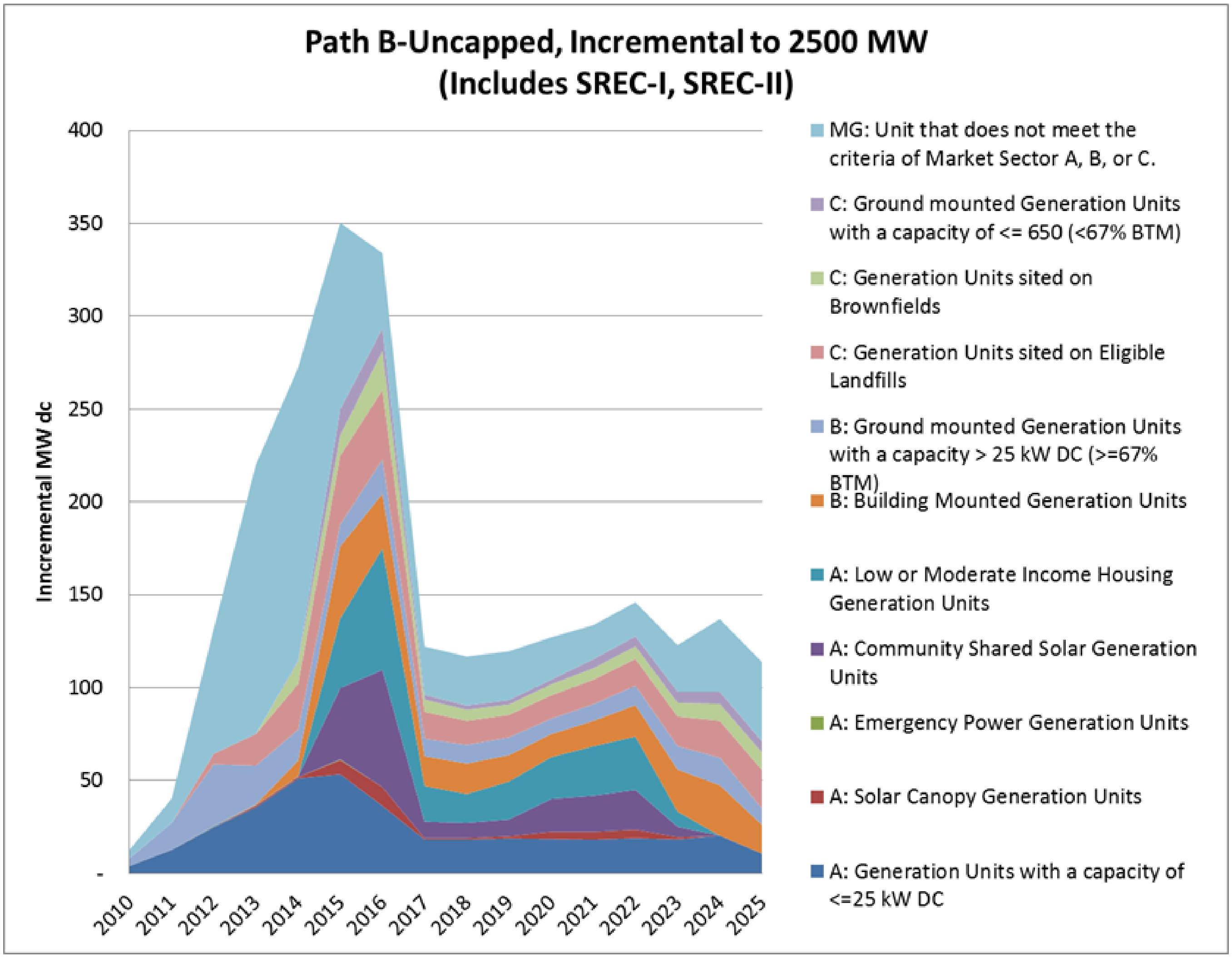
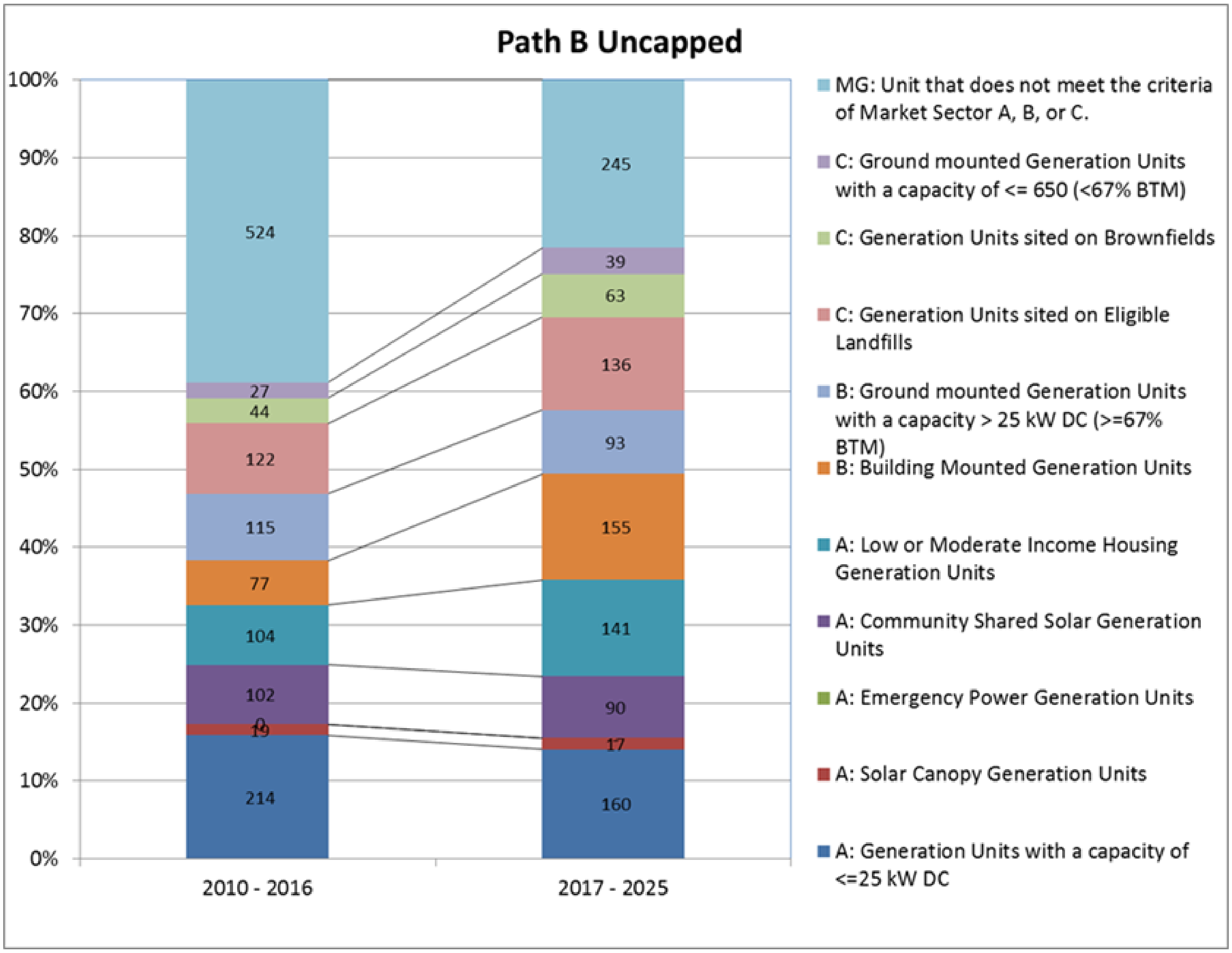


Figure 38: Policy B Uncapped Subsector Market Share Comparison Before and After 2017



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.

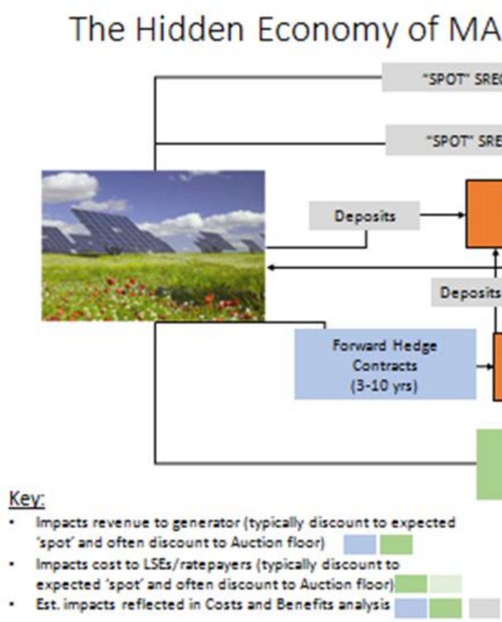
- Modeled estimates of SREC prices using SEA's proprietary Massachusetts Solar Market Study fundamentals analysis of resulting in supply, demand and ultimately SREC spot prices, as well as floor-price auction dynamics.

- 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 40, 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 39: Schematic Diagram of Hedging Transactions within the SREC Carve-out Market



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

Figure 40 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 41 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 40:
Historic and Predicted SREC Spot Prices with Net Metering Caps Unchanged from Present Policy

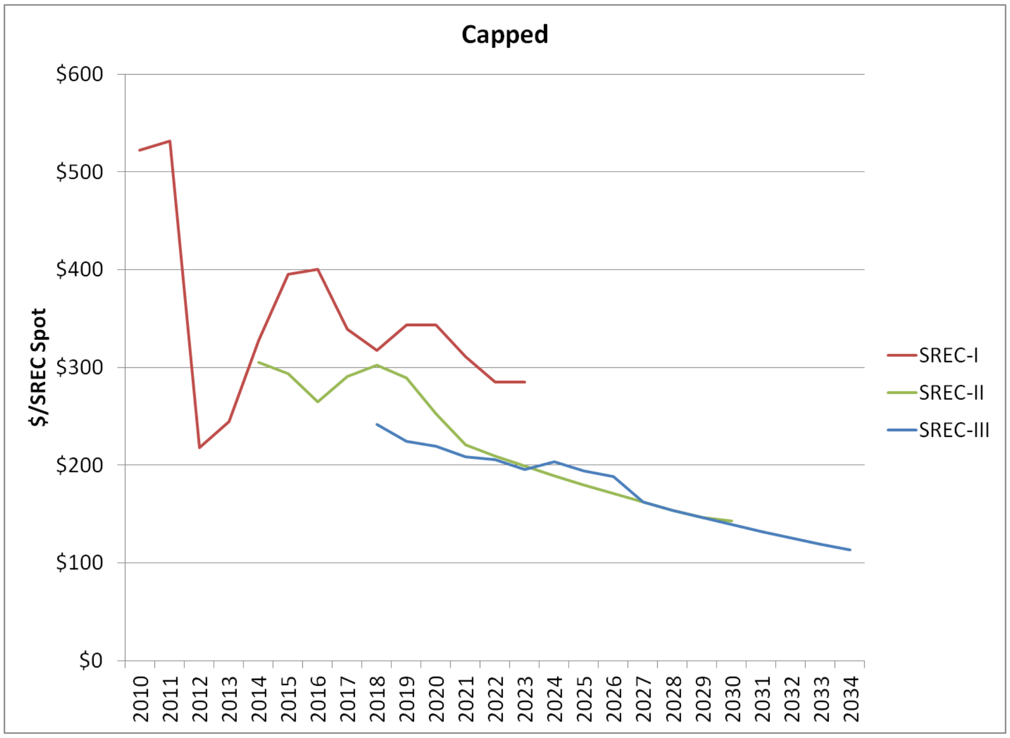
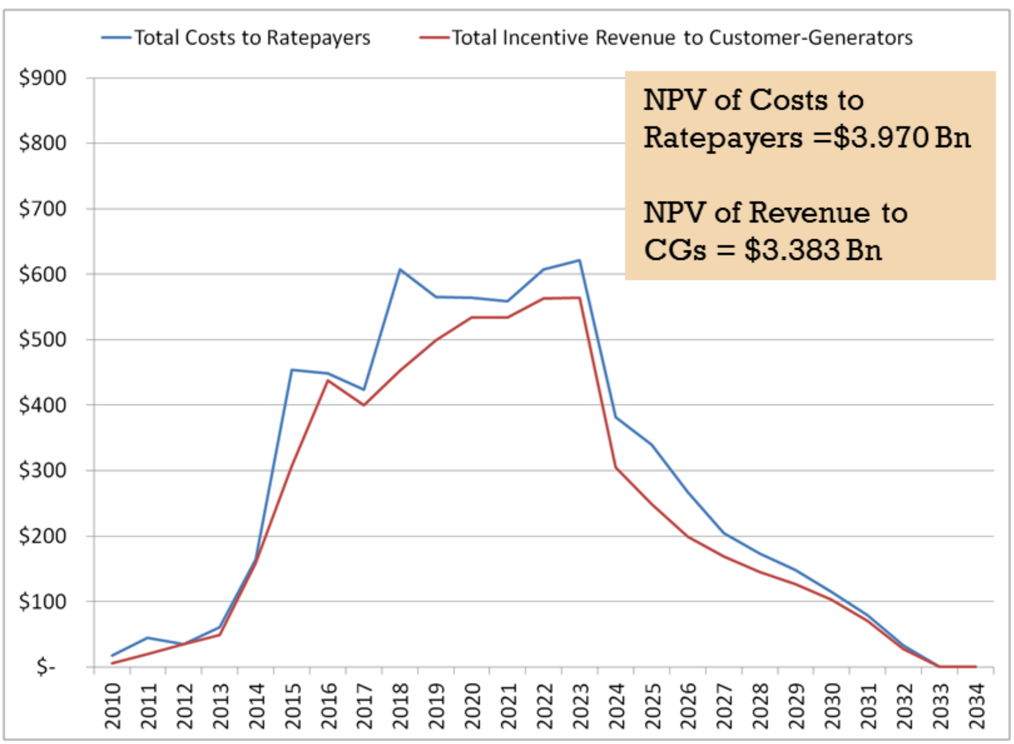


Figure 41: Annual Realized Costs NPRs and Revenues to CGs with Net Metering Caps Unchanged from Present Policy



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

Figure 42 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 43 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 42: Historic and Predicted SREC Spot Prices with Net Metering Uncapped

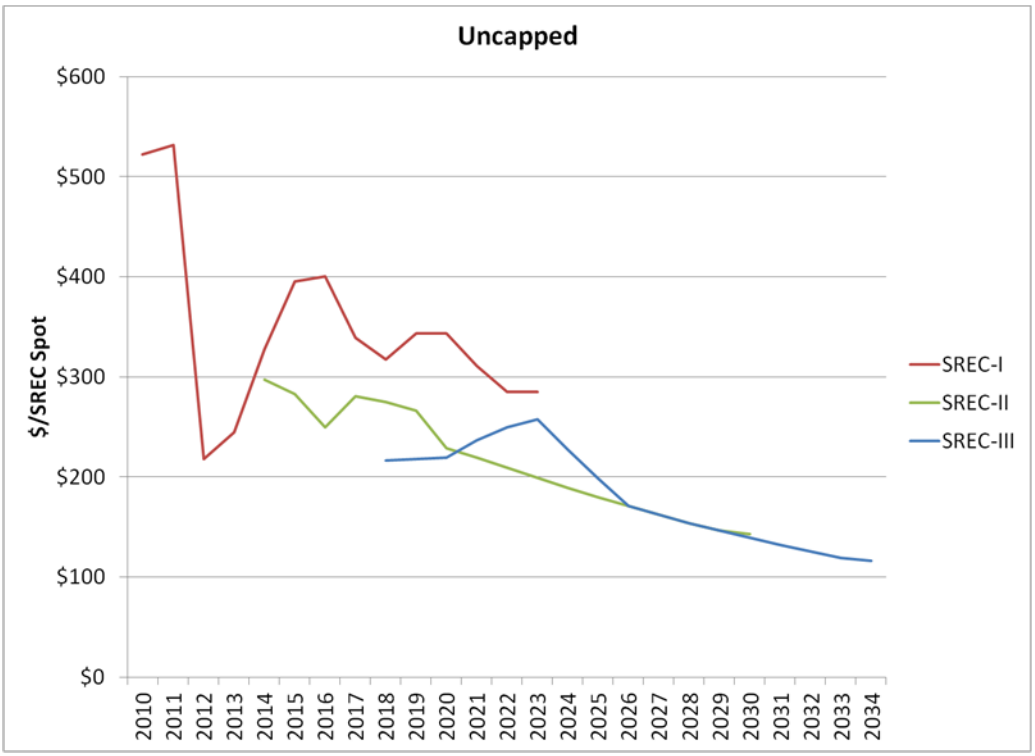
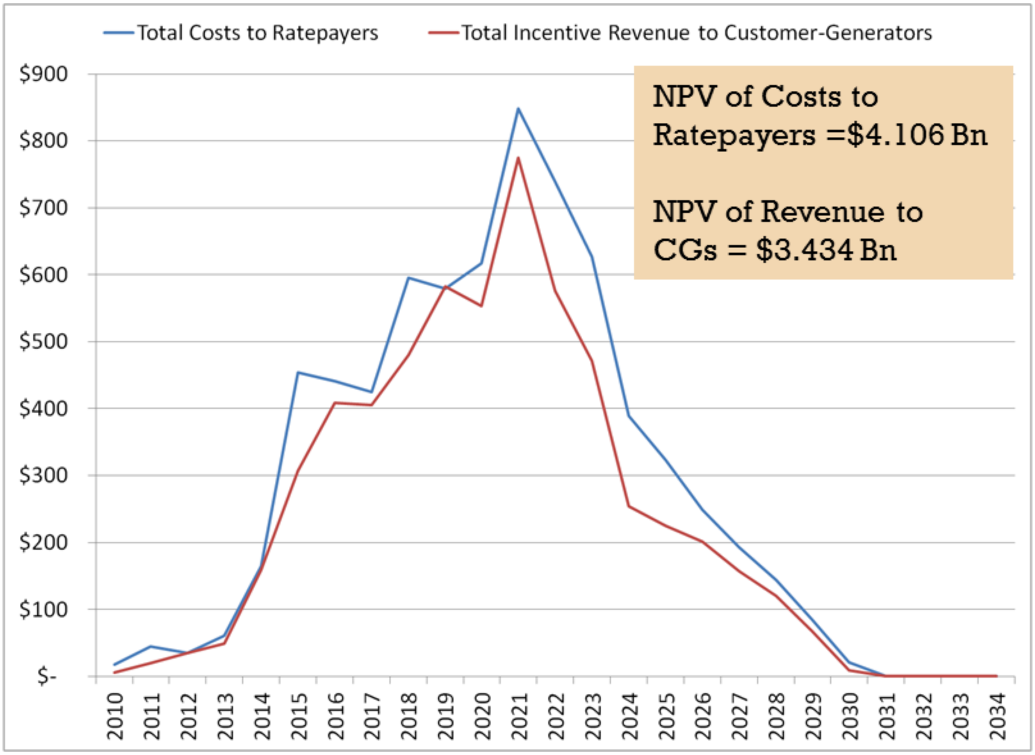


Figure 43: Annual Realized Costs NPRs and Revenues to CGs with Net Metering Caps Uncapped



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 44 and Figure 45 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 44: $/MWh Incentives for the Path A Capped Small Residential Program

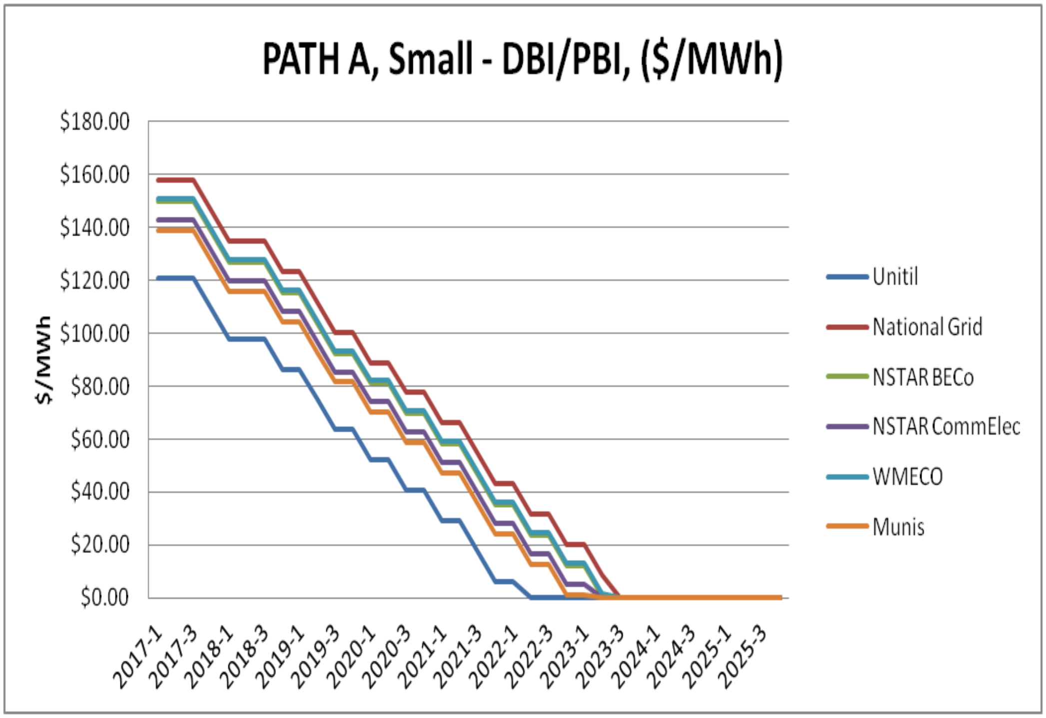
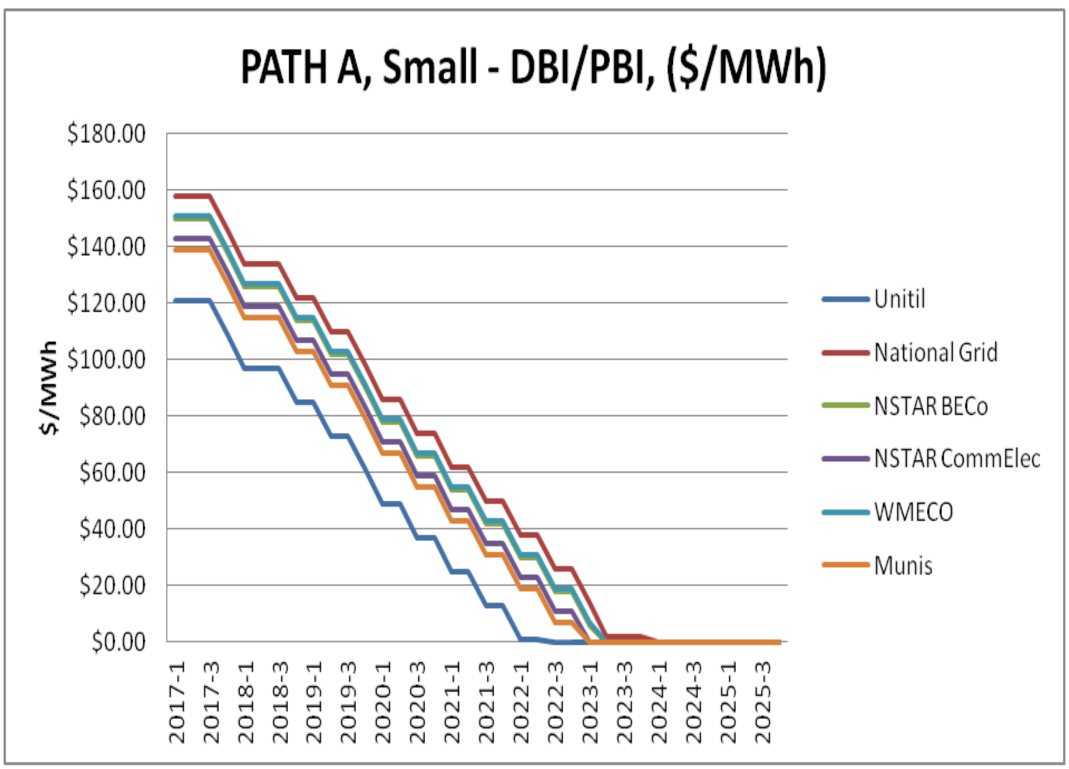


Figure 45: $/MWh Incentives for the Path A Capped Small Residential Program



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 46. While the combined incentive over time decreases, it never reaches the level where additional solar incentives are not needed.

Figure 46: $/MWh Incentives for the Path A Capped Large Sector A Program

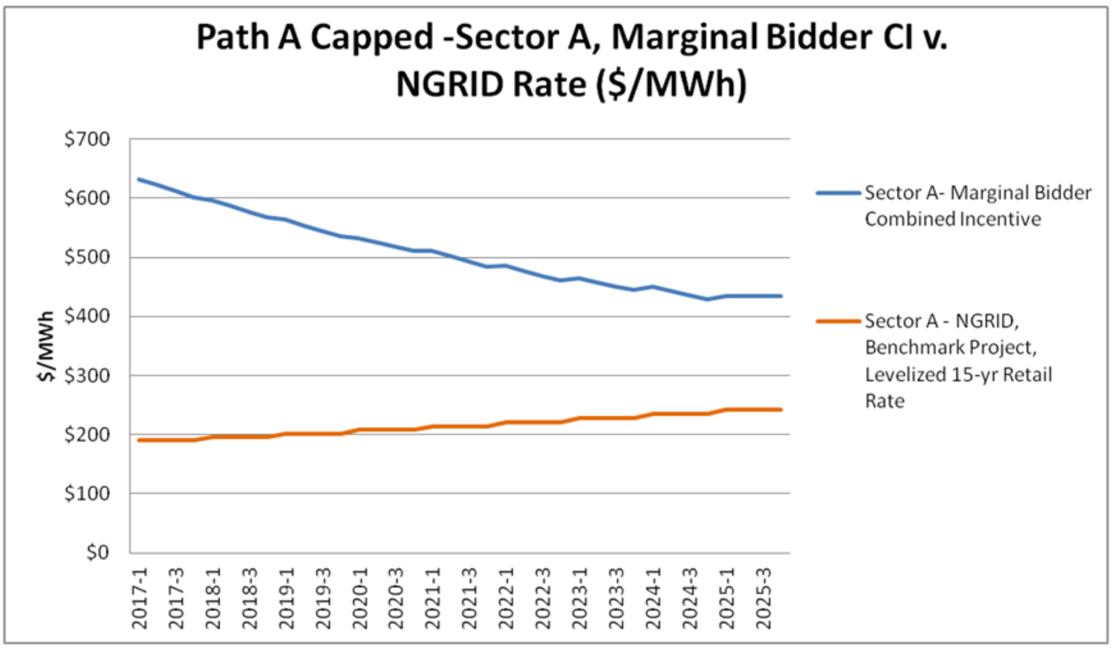
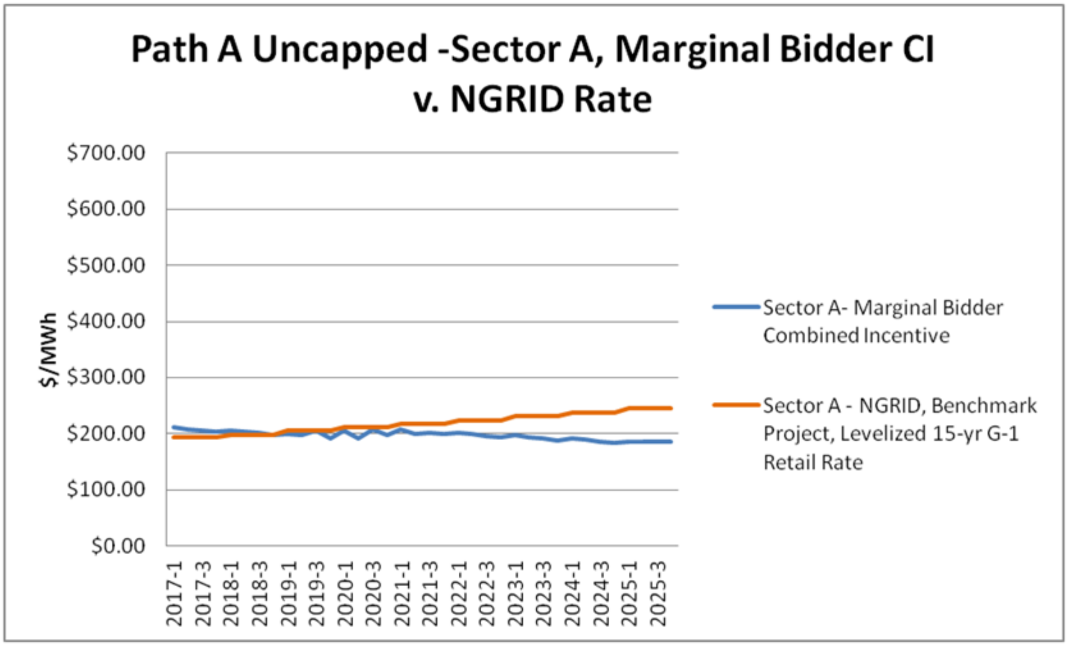


Figure 47 shows the $/MWh incentives but this time for the uncapped scenario for Policy Path A that now includes VNM-dependent projects (CSS and VNM Affordable Housing). As can be seen, for a project sized to load[78] the combined incentive needed from the marginal bidder becomes lower than the combined 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.

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

Figure 47: $/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 48); it reaches grid parity in approximately 2023 for most utilities. The uncapped scenario is exactly the same as the capped scenario (see Figure 49).

Figure 48: $/kW Incentives for the Path B Capped Small Residential Program

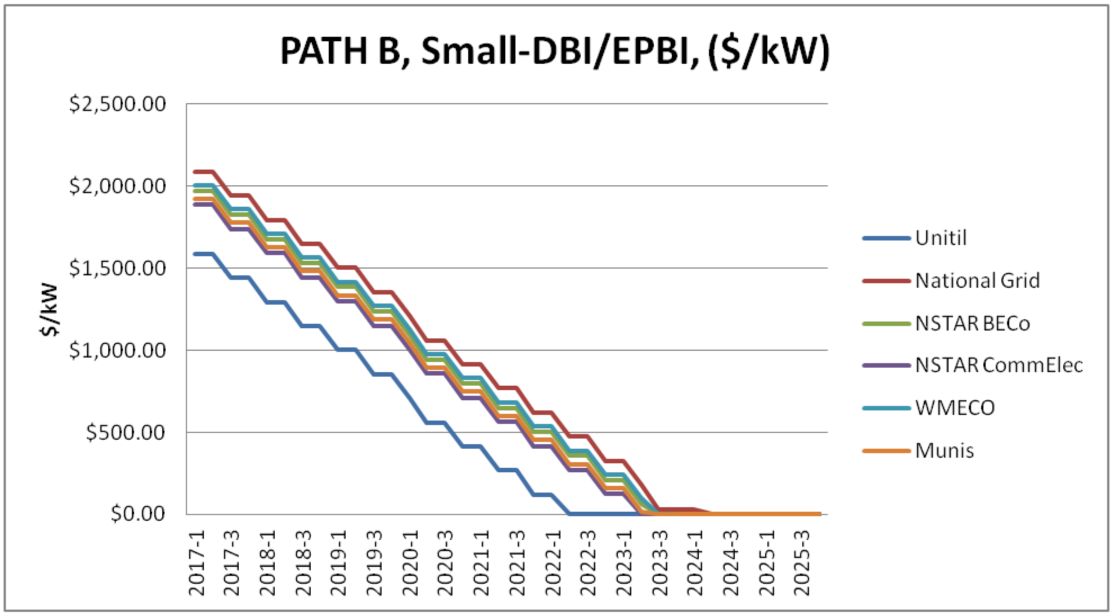
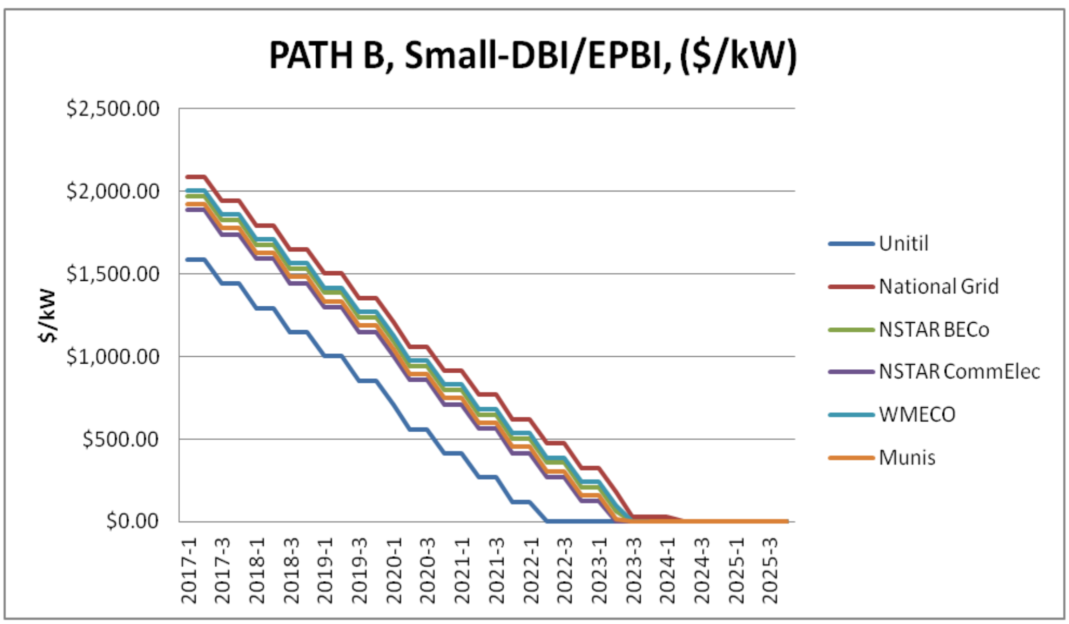


Figure 49: $/kW Incentives for the Path B Uncapped Small Residential Program



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 50. 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 50: $/MWh Incentives for the Path B Capped Large Sector A Program

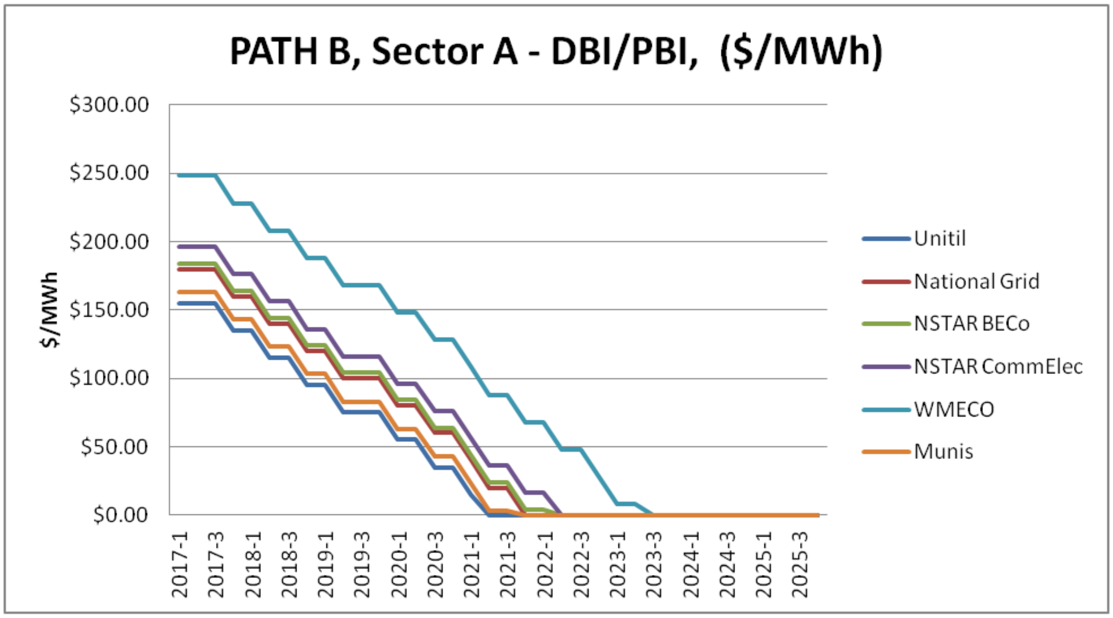
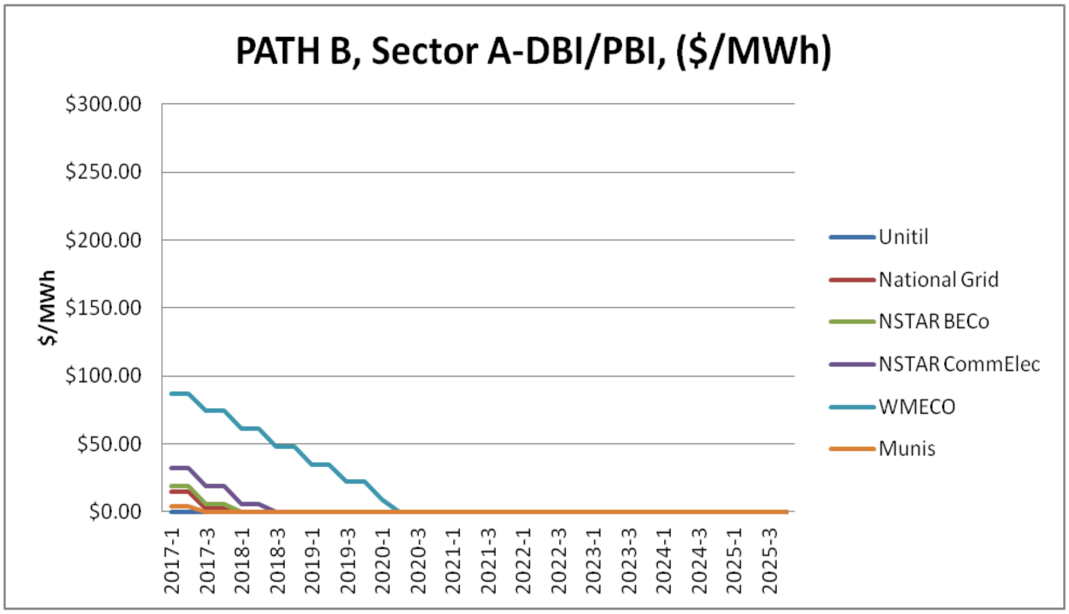


Figure 51 shows the $/MWh incentives, but this time for the uncapped scenario for Policy Path A, and now includes VNM-dependent projects (CSS and VNM Affordable Housing). Again the solar incentive needed from the marginal bidder drops to zero very quickly, as CSS and VNM Affordable Housing can exist 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 51: $/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 52, 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.

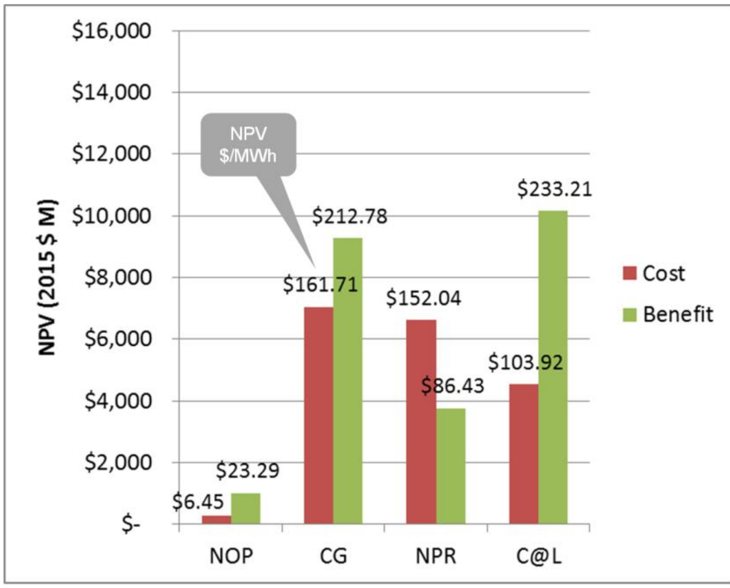
Non-participating ratepayers (NPRs) fund the incentives, so it is no surprise that they incur net costs. NPV costs are $6.6 billion compared to benefits of $3.766 billion. While the table below does not break out the relative costs and benefits of SREC-I vs. SREC-II, SREC-II is notably more cost-effective 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[79] of NPV $4.5 billion.

[79] 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

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

A Figure 52: 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.

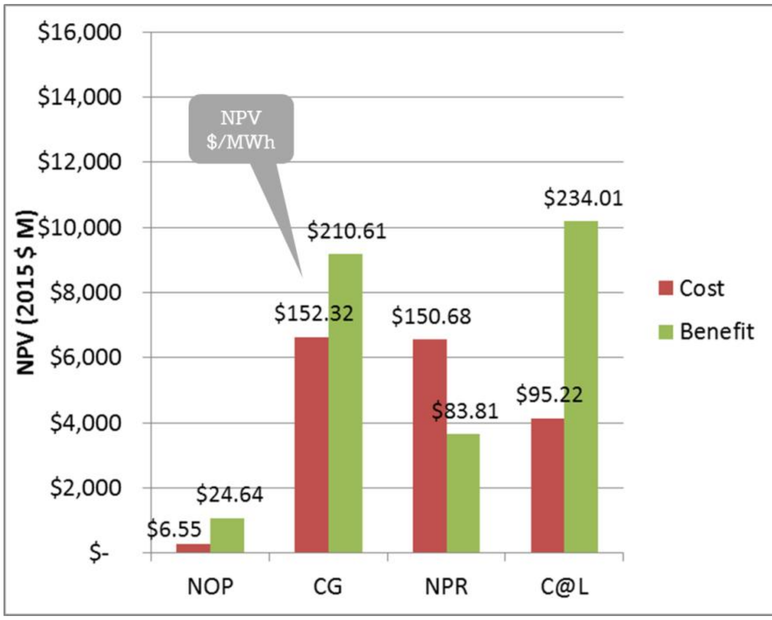
From the CG perspective, they are projected to experience benefits of NPV $9.2 billion (slightly less than under the capped s scenario) compared to costs of $6.6 billion. This reflects a different mix of generation units more heavily weighted towards larger projects with lower $/kW installed costs, resulting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

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.

Figure 53: 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 54 retains the same overall shape as A Figure 52 and Figure 53, 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.

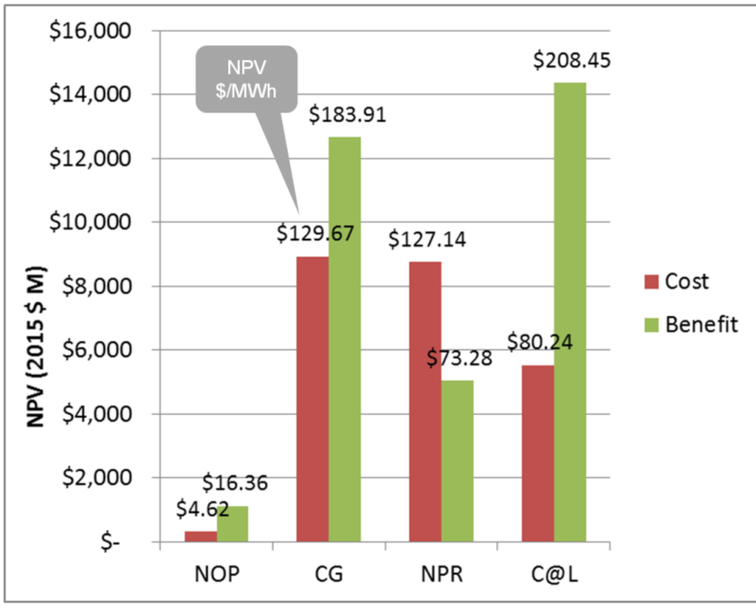
NOPs, the beneficiaries of lease payments, property tax or PILOT payments, or PPA or net metering discounts, would experience a similar level of benefits at $1.1 billion as at 1600 MW, but experience an increase in costs (tax liabilities) of NPV $318 million. It is clear why the NOP net benefits decrease, 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 <u>for SREC-III, the incremental benefits exceeded the incremental costs from the NPR perspective</u>.

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 54: 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 52, Table 53,Table 54, and Table 55 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 52 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 52, 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 52: Comparing NOP Detailed Costs and Benefits – SREC Capped

Benefits

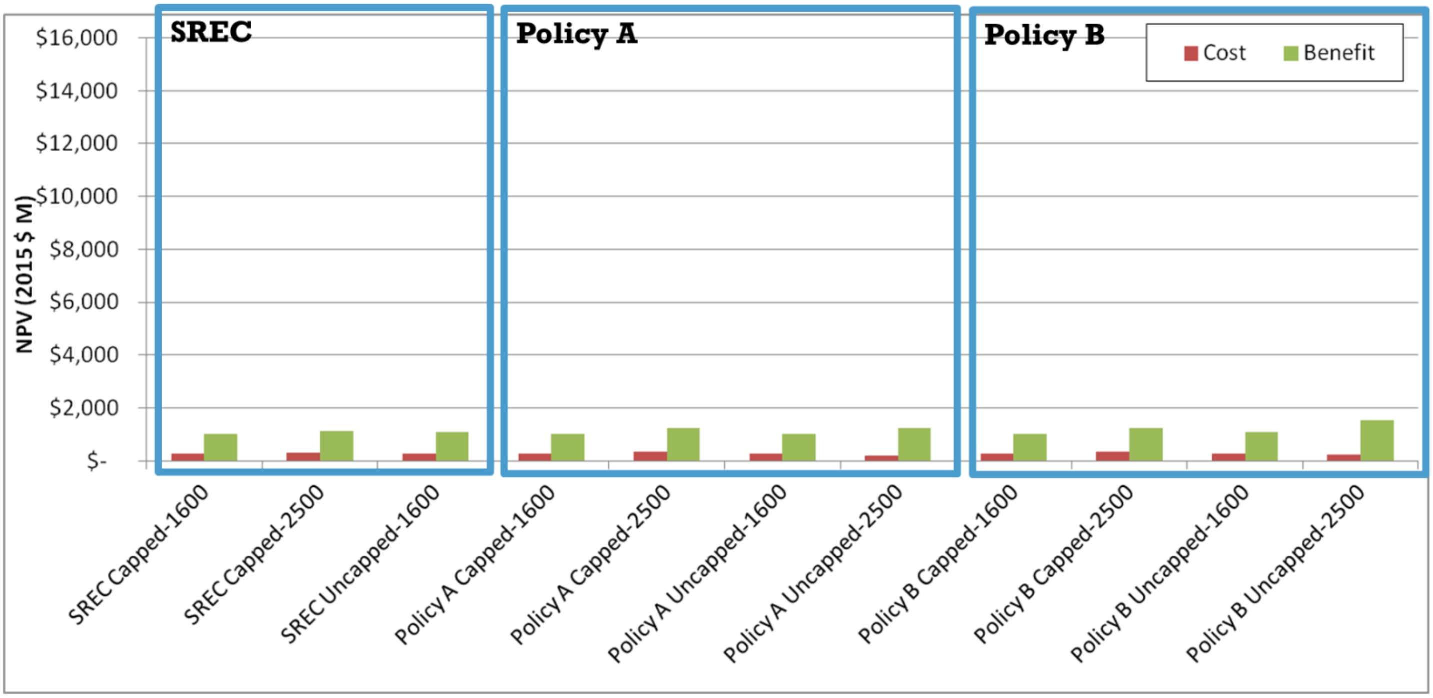
C/B Component ↓	CB Code	2500 MW NPV Benefits (Million $)	2500 MW NPV $/MWh Benefits	1600 MW NPV Benefits (Million $)	1600 MW NPV $/MWh Benefits
Lease Payments	CB1.3	$ 228.2	$ 3.3	$ 209.0	$ 4.8
PILOTs / Property Taxes	CB1.4	$ 152.6	$ 2.2	$ 148.1	$ 3.4
Generation Value of On-site Generation	CB3.1	$ 155.3	$ 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 55 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 55: 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 53 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 53: Comparing CG Detailed Costs and Benefits – SREC Capped

Benefits

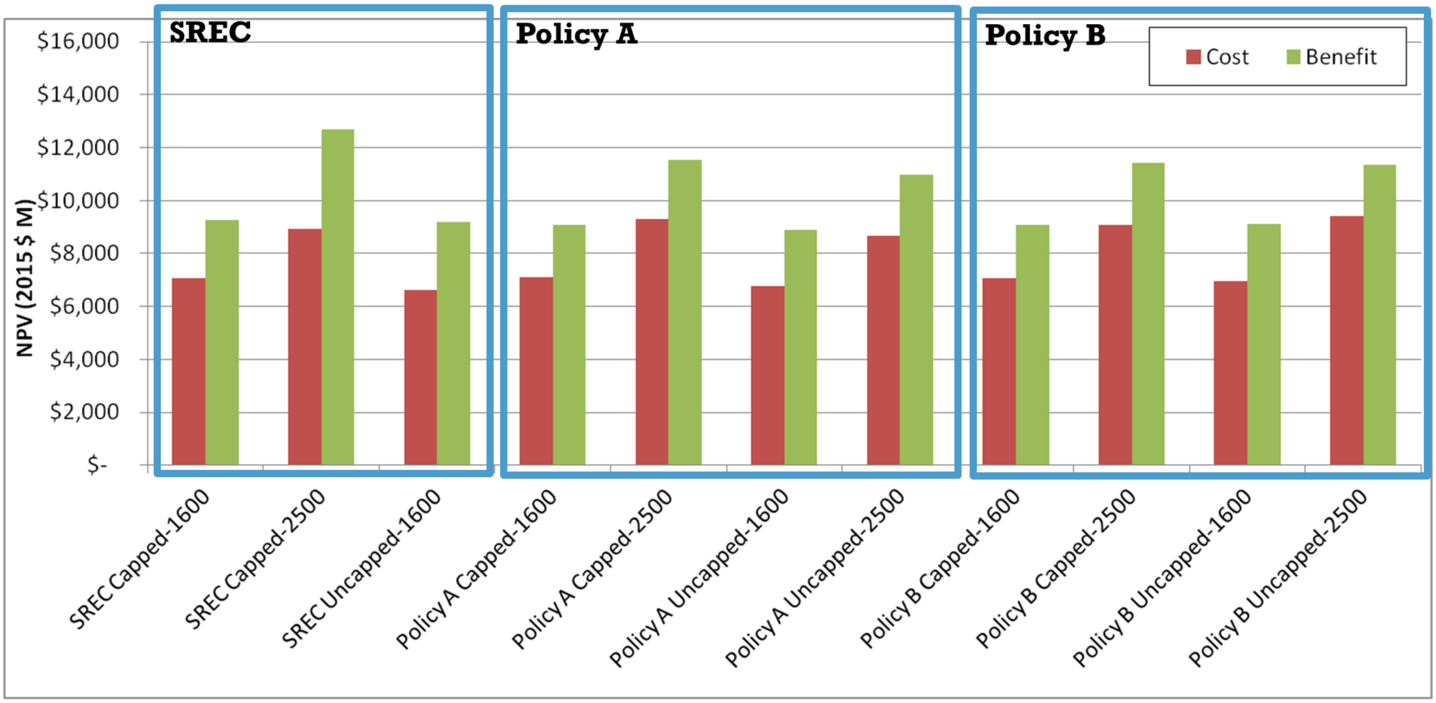
C/B Component ↓	CB Code	2500 MW NPV Benefits (Million $)	2500 MW NPV $/MWh Benefits	1600 MW NPV Benefits (Million $)	1600 MW NPV $/MWh Benefits
ROI (Aggregate Return to Debt & Equity)	CB1.5	$ -	$ -	$ -	$ -
MA Residential RE Tax Credit	CB1.6.a	$ 134.0	$ 1.9	$ 56.7	$ 1.3
Federal Incentives (ITC)	CB1.7a	$ 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

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
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 56 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 56: 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 54 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 54: Comparing NPR Detailed Costs and Benefits – SREC Capped

Benefits

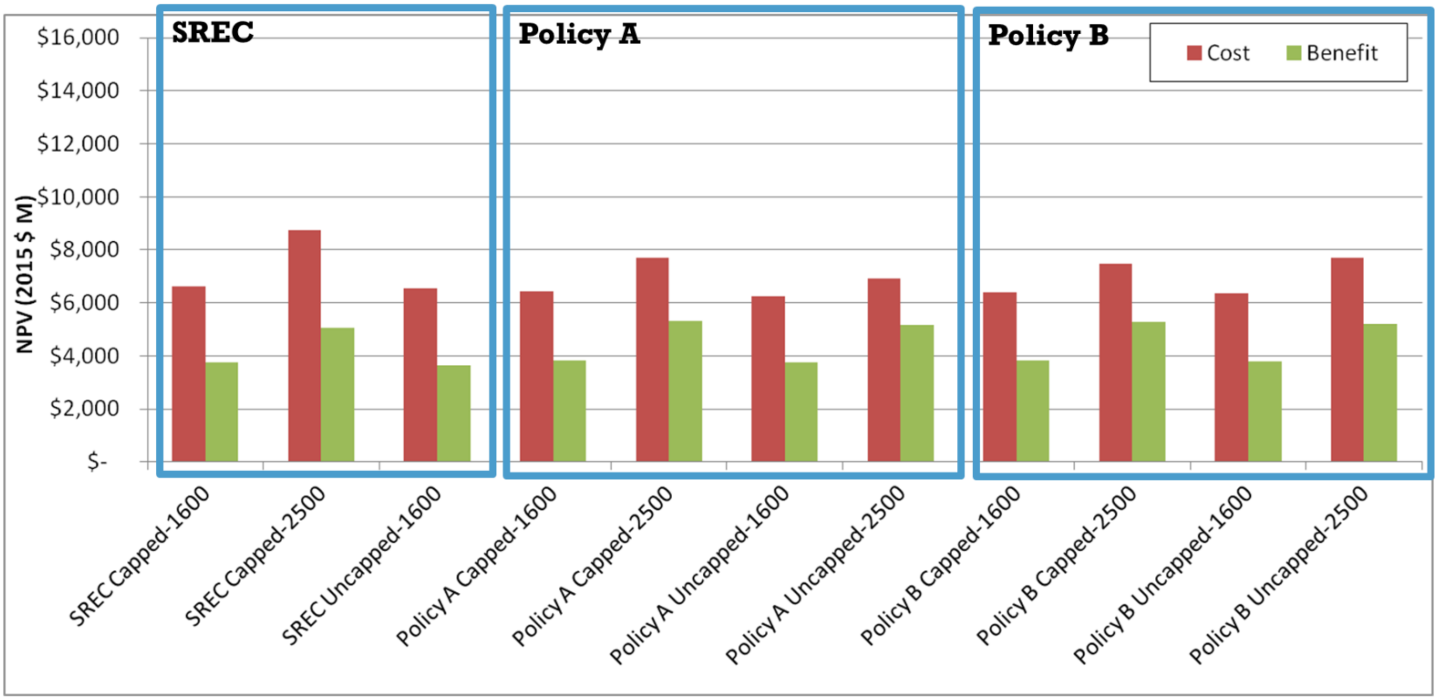
C/B Component ↓	CB Code	2500 MW NPV Benefits (Million $)	2500 MW NPV $/MWh Benefits	1600 MW NPV Benefits (Million $)	1600 MW NPV $/MWh Benefits
MA Income Taxes	CB1.6.b	$ 146.9	$ 2.1	$ 150.1	$ 3.4
Displaced RPS Class I Compliance Costs	CB2.3	$ 1,471.6	$ 21.4	$ 921.8	$ 21.2
Generation Value of On-site 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 57 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 57: 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 55 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 55: Comparing C@L Detailed Costs and Benefits – SREC Capped

Benefits

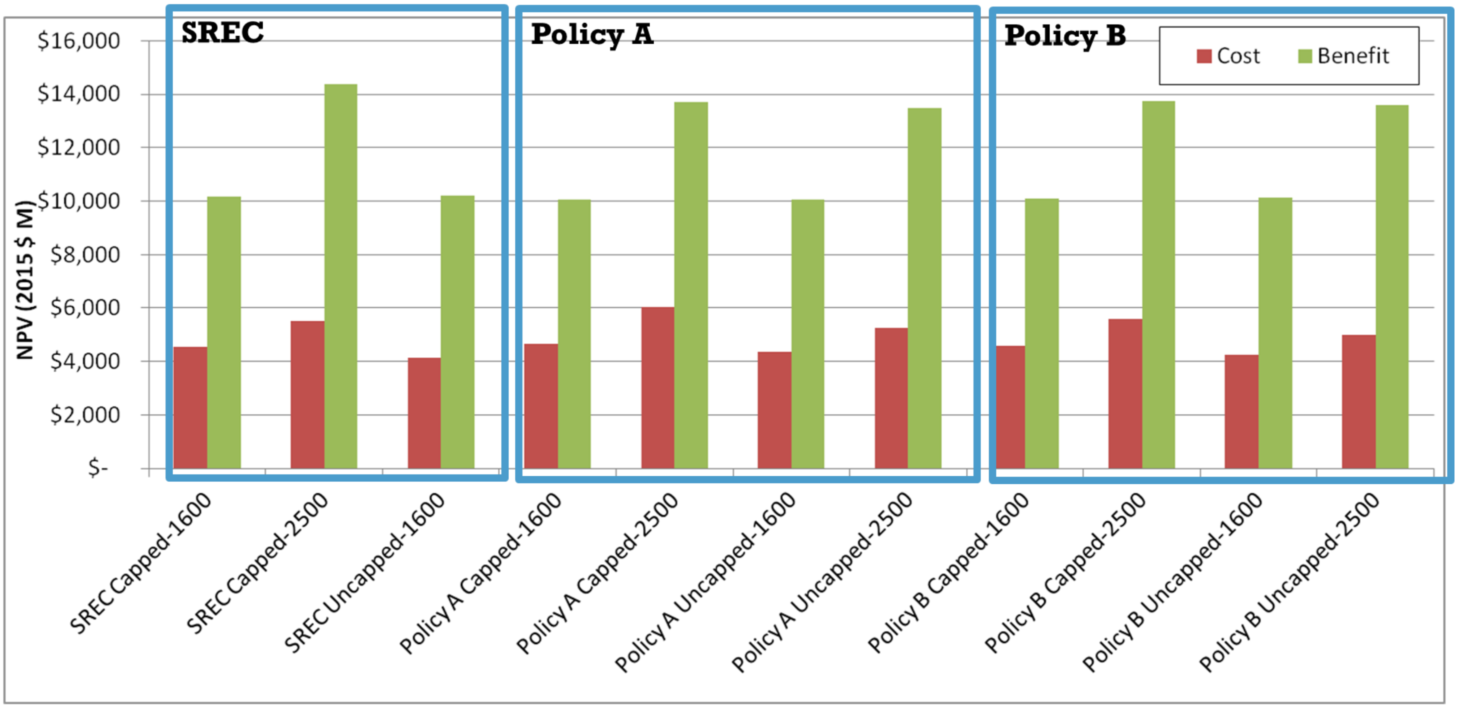
C/B Component ↓	CB Code	2500 MW NPV Benefits (Million $)	2500 MW NPV $/MWh Benefits	1600 MW NPV Benefits (Million $)	1600 MW NPV $/MWh Benefits
System Installed Costs	CB1.1	$ 2,812.6	$ 40.8	$ 2,176.9	$ 50.0
Ongoing O&M + Insurance Costs	CB1.2	$ 884.9	$ 12.8	$ 627.4	$ 14.4
Lease Payments	CB1.3	$ 228.2	$ 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 58 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 58: 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).

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- 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 56 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 56: 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,[80] this amount of solar development has created an estimated 14,762 total job-years in the state.[81]

Table 57: 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.

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

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[80] 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.

[81] 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.

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.

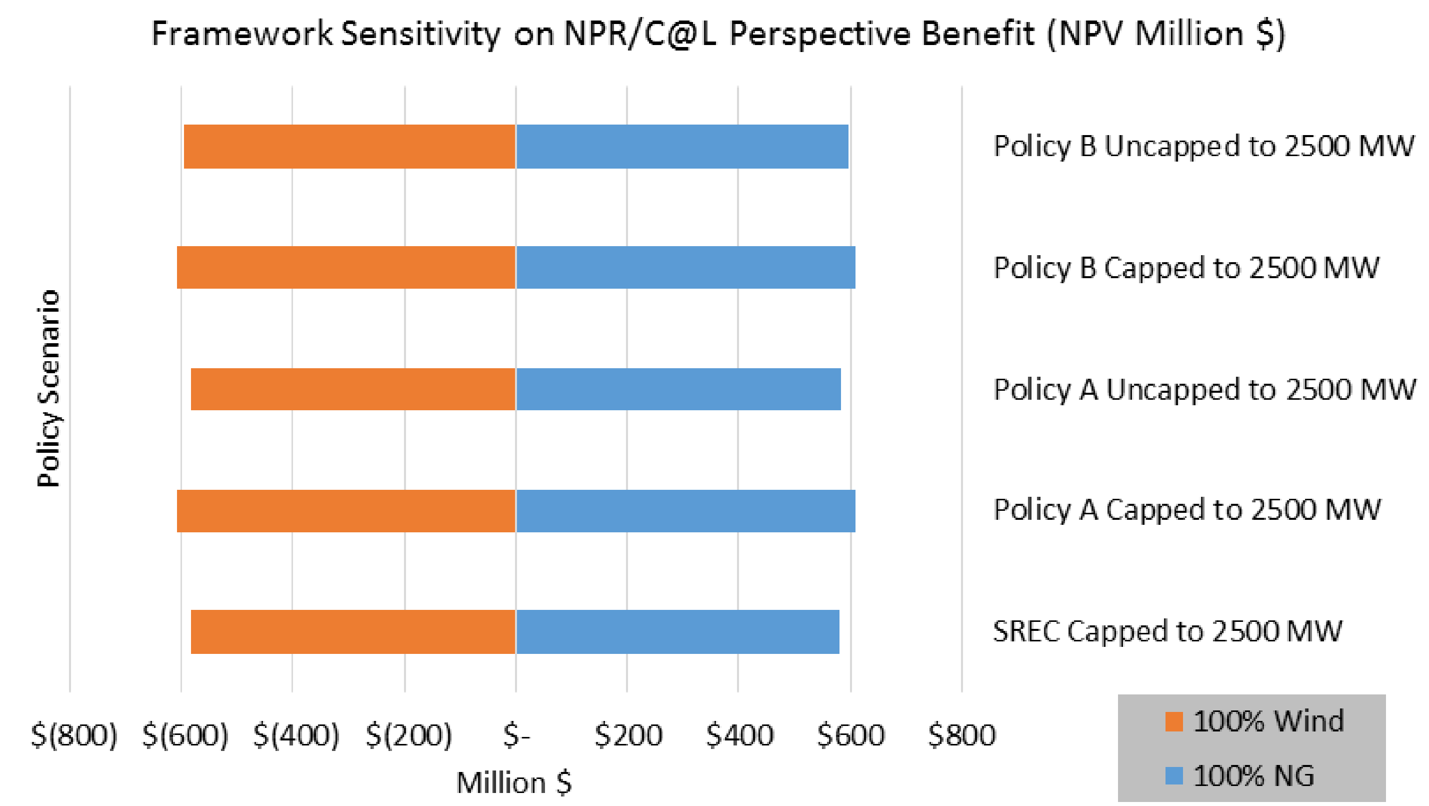
The ancillary grid services provided by resilient solar installations can result in benefits for both customer generators and the citizens of Massachusetts at large. If customer generators are able to monetize a portion of the benefits described above, the system's benefits may outweight the additional 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 59. As can be seen, the maximum variation in these assumptions can vary the total Benefits to each perspective of about NPV $$600 million.

Figure 59: 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 58, 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 58: 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 59 summarizes the results of a +10% sensitivity analysis for each parameter for Policy Path A to 2500 MW (Uncapped).[82] 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

[82] 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.

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

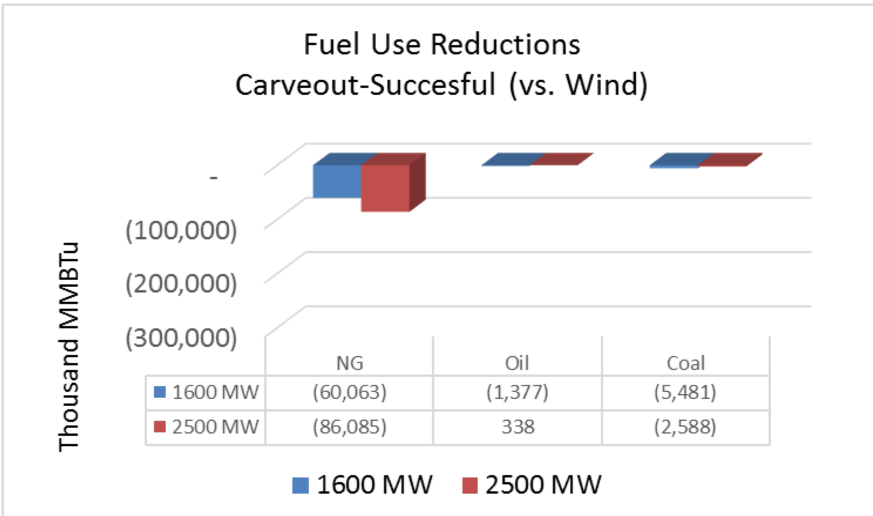
		Parameter	Selected Parameter	Selected Value	Base	Sensitivity	NOP		CG		NPR		C@L	
							C	B	C	B	C	B	C	B
System Installed Costs	CB1.1	A	Sensitivity	52.0%	42%	52.0%	$ -	$ -	$ -	$ -	$ -	($1.86)	$ -	$621.82
Ongoing O&M + Insurance Costs	CB1.2	A	Sensitivity	74.0%	64%	74.0%	$ -	$ -	$ -	$ -	$ -	($1.86)	$ -	$86.07
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

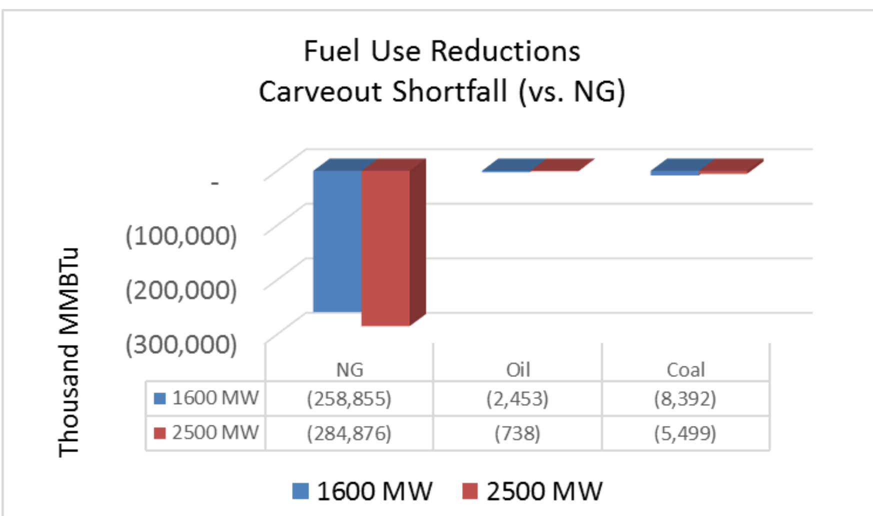
Figure 60 and Figure 61 show the amount of natural gas, oil and coal displaced by 1600 MW and 2500 MW of solar capacity. In both cases, it is assumed that Massachusetts solar would displace natural gas until 2018. Starting from 2018, Figure 60 assumes solar would displace wind under RPS Class I in the absence of a solar carveout policy. Figure 61 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 60: Fuel Use Reductions under Carveout-Successful Framework



	NG	Oil	Coal
1600 MW	(60,063)	(1,377)	(5,481)
2500 MW	(86,085)	338	(2,588)

Figure 61 – Reductions under Carveout Shortfall Framework



	NG	Oil	Coal
1600 MW	(258,855)	(2,453)	(8,392)
2500 MW	(284,876)	(738)	(5,499)

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 62 assumes solar would continue to displace RPS Class I compliance met by wind in the absence of a solar carveout policy. Figure 63 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 62: Emissions Reductions under Carveout-Successful Framework

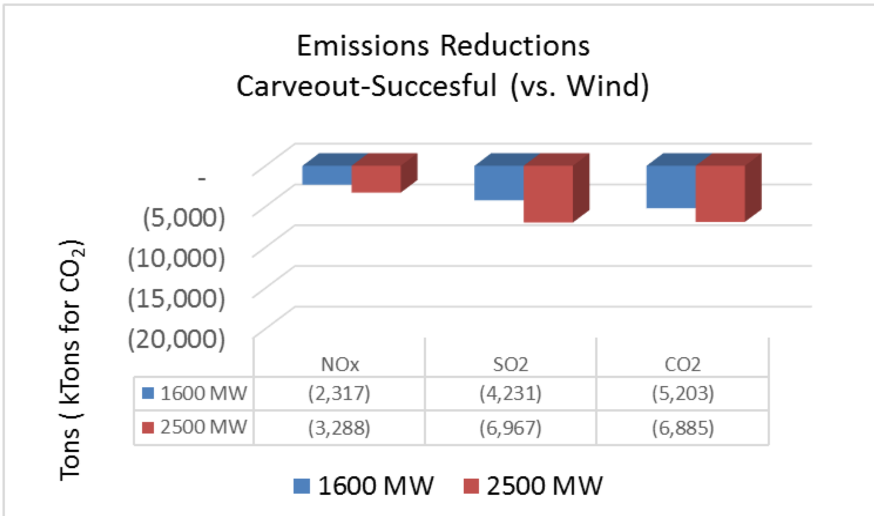
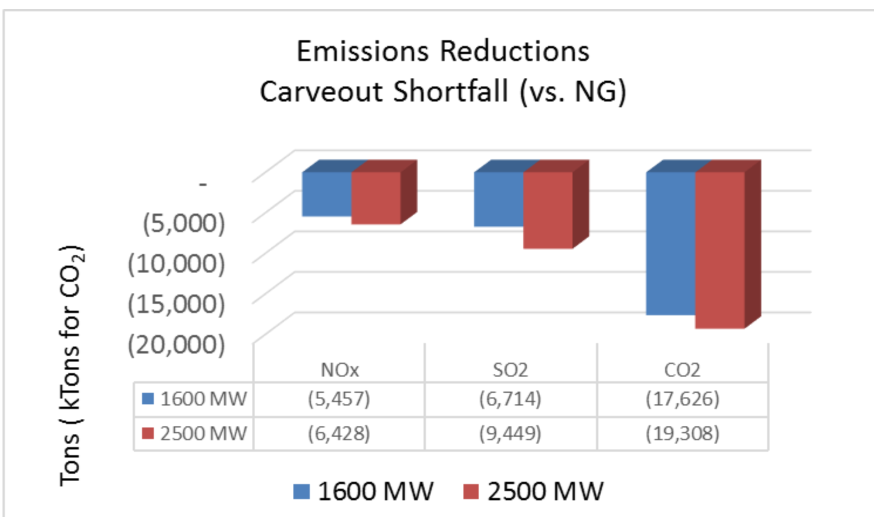


Figure 63: Emissions Reductions under Carveout Shortfall Framework



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 60 through Table 62 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

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).

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 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 60: 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 61: 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 62: 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.

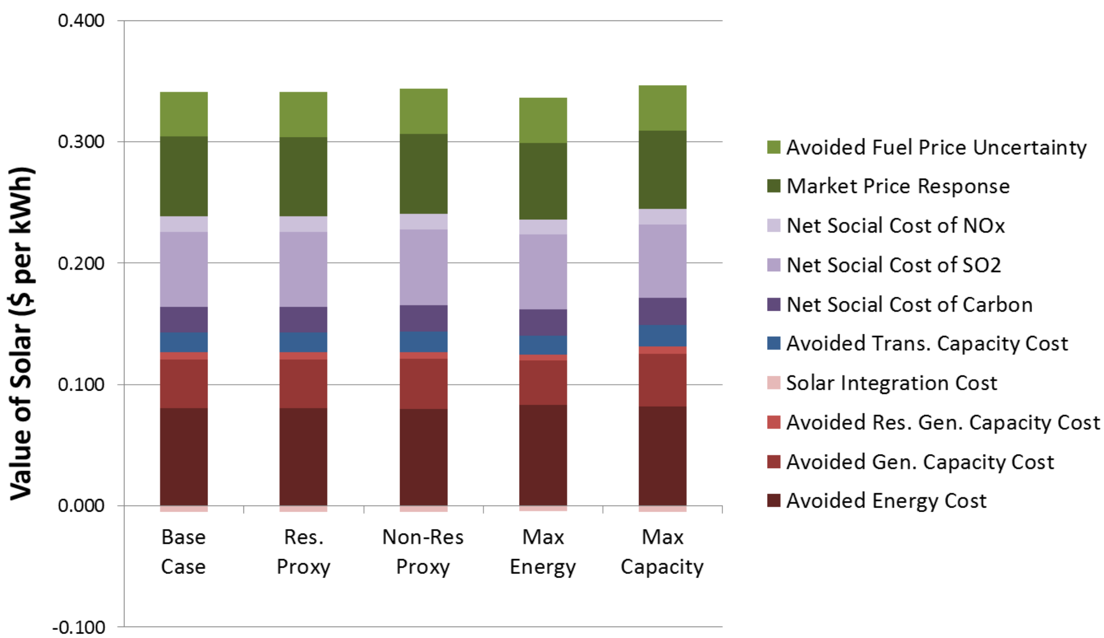
12.3.1.2 Financing Costs

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 64). (Clean Power Research, LLC; Sustainable Energy Advantage, LLC; Perez Richard; Pace Law School Energy and Climate Center, 2015)

Figure 64: 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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Task 3 – Evaluating the Costs and Benefits of Alternative Net Metering and Solar Policy Options in Massachusetts

Errata 1, 2 and 3 - Corrections

April 30, 2015

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Errata 1 and 2

ERRATA 1: the calculations in the April 27, 2015 final report, and the, cost and benefit Roll-Up Master spreadsheet distributed to Task Force members, erroneously included **both** a fixed 33% peak reduction factor for the two T&D investment deferral line-items shown below, **as well as** the correct Distribution-Level Peak Load Reduction values. In other words, the reductions to impact to take account of solar PV's peak coincidence were applied twice.

Avoided Transmission Investment - Local	CB6.2
Avoided Distribution Investment	CB6.3

These were the only components of the analysis that were calculated under a distinct analysis and then transferred into the rollup. The result is that the benefits calculated for both of these benefits were reports as 1/3 of what they should have been. The impact on the total benefit:cost metrics are small; the revised metrics as initially presented in the executive summary (Tables 1 and 2) and Section 12 (Tables 27 – 29) of the report, are shown below. The only changes increase the NPR and C@L benefits to a modest degree.

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	$	5,270.6	$	3,958.8
	B:C Ratio		0.60		0.60
C@L	NPV of Costs	$	5,526.9	$	4,528.0
C@L	NPV of Benefits	$	14,581.0	$	10,354.3
	B:C Ratio	$	2.64	$	2.29
NB(C@L):NC(NPR) Ratio			2.60		2.19

SREC Uncapped		2500 MW	1600 MW
		NPV	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	$ 3,841.1
	B:C Ratio	#N/A	0.59
C@L	NPV of Costs	#N/A	$ 4,145.4
C@L	NPV of Benefits	#N/A	$ 10,379.9
	B:C Ratio	#N/A	$ 2.50
NB(C@L):NC(NPR) Ratio		#N/A	2.29

Policy A Capped		2500 MW	1600 MW
		NPV	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	$ 5,549.5	$ 4,035.8
	B:C Ratio	0.72	0.63
C@L	NPV of Costs	$ 6,035.8	$ 4,667.9
C@L	NPV of Benefits	$ 13,954.3	$ 10,268.0
	B:C Ratio	$ 2.31	$ 2.20
NB(C@L):NC(NPR) Ratio		3.68	2.32

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	$	5,410.4	$	3,965.6
	B:C Ratio		0.78		0.63
C@L	NPV of Costs	$	5,271.6	$	4,347.5
C@L	NPV of Benefits	$	13,718.3	$	10,248.4
	B:C Ratio	$	2.60	$	2.36
NB(C@L):NC(NPR) Ratio			5.57		2.58

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	$	5,514.8	$	4,030.4
	B:C Ratio		0.74		0.63
C@L	NPV of Costs	$	5,606.2	$	4,590.7
C@L	NPV of Benefits	$	13,986.6	$	10,278.3
	B:C Ratio	$	2.49	$	2.24
NB(C@L):NC(NPR) Ratio			4.25		2.39

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	$ 5,450.2	$ 3,977.0
	B:C Ratio	0.71	0.62
C@L	NPV of Costs	$ 4,989.0	$ 4,263.7
C@L	NPV of Benefits	$ 13,816.7	$ 10,317.0
	B:C Ratio	$ 2.77	$ 2.42
NB(C@L):NC(NPR) Ratio		3.95	2.52

ERRATA 2: The values appearing in the detailed cost and benefit components for Avoided Transmission Investment and Avoided Distribution Investment – Local, in the roll-up master spreadsheet provided to task force members, were reversed. The total costs and benefits are unaffected by correction of this reversal, as impacts affecting the same perspectives were simply placed in the wrong rows.

An amended roll-up spreadsheet is provided along with this Errata Report, with totals appearing in the correct rows.

Referring to the earlier roll-up master spreadsheet provided to Task Force members, the reader may for each of these tables simply read the figures labeled as

Avoided Transmission Investment - Local	CB6.2

to be

Avoided Distribution Investment	CB6.3

and vice versa.

ERRATA 3: The same two benefit component line items were omitted from the cost and benefit component detail tables appearing in Section 8 and Appendix B of the Task 3 report. These line items only impact the NPR and C@L perspectives as benefits.

Avoided Transmission Investment - Local	CB6.2
Avoided Distribution Investment	CB6.3

This issue only occurred in extracting the values from models for creating report tables in Section 6 and Appendix B. The correct totals of benefits and costs were used in deriving all totals used in calculating benefit to cost ratios throughout the report.

Tables 21 and 22 from the Task 3 Report are also in error and the corrections appear here. A corrected Appendix B is also provided below.

Table 2163: Comparing NPR Detailed Costs and Benefits – SREC Capped (ERRATA)

Benefits

		2500 MW		1600 MW	
C/B Component ↓	CB Code	NPV Benefits (Million $)	NPV $/MWh Benefits	NPV Benefits (Million $)	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 Transmission Investment - Local	CB6.2	$ 102.5	$ 1.5	$ 88.6	$ 2.0
Avoided Distribution Investment	CB6.3	$ 232.4	$ 3.4	$ 200.9	$ 4.6
Avoided Environmental Impacts	CB7.1	$ 710.8	$ 10.3	$ 660.0	$ 15.1
Total		**$ 5,270.6**	**$ 76.5**	**$ 3,958.8**	**$ 90.9**

Costs

		2500 MW		1600 MW	
C/B Component ↓	CB Code	NPV Costs (Million $)	NPV$/MWh Costs	NPV Costs (Million $)	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**

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

Benefits

		2500 MW		1600 MW	
C/B Component ↓	CB Code	NPV Benefits (Million $)	NPV $/MWh Benefits	NPV Benefits (Million $)	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 Transmission Investment - Local	CB6.2	$ 102.5	$ 1.5	$ 88.6	$ 2.0
Avoided Distribution Investment	CB6.3	$ 232.4	$ 3.4	$ 200.9	$ 4.6
Avoided Environmental Impacts	CB7.1	$ 710.8	$ 10.3	$ 660.0	$ 15.1
Total		**$ 14,581.0**	**$ 211.7**	**$ 10,354.3**	**$ 237.6**

Costs

		2500 MW		1600 MW	
C/B Component ↓	CB Code	NPV Costs (Million $)	NPV$/MWh Costs	NPV Costs (Million $)	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**

Massachusetts Net Metering and Solar Task Force

Task 4 – Options to Reach the 1600 MW Goals

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Contents

1 Introduction and Summary

In order to conduct the modeling in Task 3, the Task Force first had to select the potential futures, or "policy paths", to be modeled. To make this selection, the Task Force used the following process. Based on the research conducted in Tasks 1 and 2, stakeholder objectives as expressed in the focus groups conducted in Task 0, and public comment, the consulting team developed an initial set of 7 potential policy paths. These paths were discussed at the Task Force meeting on February 12, 2015. After the meeting, additional Task Force feedback on the paths was solicited through a survey, and a narrowed set of 3 options was presented to the Task Force on March 5, 2015. At that meeting, the Task Force modified the options and selected the set to be modeled.

In selecting these policy paths, the Task Force members made an explicit distinction between selecting paths for modeling and selecting paths for potential implementation. For the modeling exercise, the Task Force's objective was to choose paths for which the modeling would generate useful information. The selection of a path for modeling is not an indication that a majority, or indeed any, of the Task Force members would like to see that path implemented.

2 Initial Set of Policy Path Options

Based on the research conducted in Tasks 1 and 2, stakeholder objectives as expressed in the focus groups conducted in Task 0, and public comment, the consulting team developed an initial set of 7 potential policy paths. These paths were each described along the dimensions listed in the table below.

Table 64. Dimensions

Dimension	Description
Solar - Small	Treatment of small solar, including structure of incentive (e.g., rebate or performance based incentive), and process for awarding incentive (e.g., first-come-first-served or competitive solicitation)
Solar - Large	Treatment of large solar, including structure of incentive (e.g., rebate or performance based incentive), and process for awarding incentive (e.g., first-come-first-served or competitive solicitation)
Distribution	Mechanisms for allocating support for solar, e.g., targeting by geography or system type
Net metering	Rules for net metering for solar generation up to on-site load
Virtual net metering	Rules for net metering for solar generation in excess of on-site load
Net metering caps and timing of transitions	Whether to keep, extend, or remove net metering caps; timing of transition to new incentive structure
Targets/constraints	Whether targets are based on a MW goal or a budget
Quantity target/timeline	Program MW target and timeline (e.g., 1600 MW by 2020)

Using these dimensions, the consulting team developed seven potential policy paths for presentation to the Task Force. Each path was designed to prioritize an objectives identified by one of the Task Force members and was based on an incentive system in place in another state. The paths are summarized in the Table below. They are described in detail in the PowerPoint presentation delivered to the Task Force on February 12, 2015.

Table 65. Initial Set of Policy Paths

Policy Path	Description	Analog
1. SREC Program Modifications including Long-Term Contracting Pilot	Keep the current incentive model but make adjustments that reduce costs while maintaining benefits	MA SREC-II Program, NJ PSE&G loan program, proposed National Grid SREC pilot (2013)
2. Competitive Solicitations	Incentives set based on results of regular competitive solicitation to ensure only the most cost effective installations are built, minimizing ratepayer impacts	RI Renewable Energy Growth, CT ZREC
3. Orderly Market Evolution	Offer declining block incentive (DBI) to create market certainty and lower cost of financing while transitioning away from state incentives	CA Solar Incentive (CSI), NY Megawatt Block Program
4. Sustained Growth Adapting to Market Changes	Incentives rates automatically adjust (up or down) to market conditions through volume-based price setting	CA Renewable Market Adjusting Tariff (ReMAT)
5. Maximize federal incentives w/ Managed Growth Boost + Sustainable Growth	Incentives rates automatically adjust (up or down) to market conditions through volume-based price setting Add tailored incentive for "managed growth" sector to capture max federal incentives before 2017	CA Renewable Market Adjusting Tariff (ReMAT)
6. Prioritize Distribution System	Target PV to support & enhance needs of the distribution system Max system owners contributions the distribution system	Hybrid w/ CT ZREC budget approach
7. Maximize Installed MW within Defined Budget	Apply measures to drive down cost premium, while limiting outlays to preset budget	CT ZREC; RI DG Growth Program

3 Survey of Task Force Members

In order to gather further input from the Task Force members, they were issued an online survey. The survey asked the Task Force members to indicate the policy path they most wanted to see modeled, either by selecting one of the paths presented at the February 12 meeting or by creating their own policy path. The survey also asked the Task Force members to provide their opinions about some of the individual potential policy elements.

The survey responses provided useful insight into the preferences of the Task Force members. The survey responses regarding the preferred policy path are set out in table below. Additional detail regarding the survey responses is available in the PowerPoint presentation delivered to the Task Force on March 5, 2015.

Table 66. Policy Path Preferences in Survey Responses

Defined Paths		Combination Paths	
Path	Responses	Path	Responses
1. SREC Program Modifications incl. LT Contracting Pilot	0	2. Competitive Solicitations + 4. Sustained Market Growth	1
2. Competitive Solicitations	1	3. Orderly Market Evolution + 4. Sustained Growth Adapting to Market Changes	5
3. Orderly Market Evolution	2	2. Competitive Solicitations + 3. Orderly Market Evolution	1
4. Sustained Growth Adapting to Market Changes	1	2. Competitive Solicitation + 6. Prioritize Distribution System	1
5. Maximize federal incentives w/ Managed Growth Boost + Sustainable Growth	1	Other: Competitive process with defined budget	1
6. Prioritize Distribution System	0		
7. Maximize Installed MW within Defined Budget	0		
No opinion	1		

4 Final Set of Policy Paths for Modeling

The consulting team used the survey responses to develop a revised set of three policy paths for the Task Force to consider at its meeting of March 5, 2015. Through discussion at the meeting, the Task Force members distilled those options into two policy paths for modeling. Those paths are set out in the table below.

Table 67. Initial Set of Policy Paths

Dimension	Path A. EDC-Centric: Competitive Solicitations	Path B. Open
Solar – Small: type	Performance-Based Incentive	Expected-Performance-Based Incentive
Solar – Small: Setting	Declining-Block Incentive with safety valve	Declining-Block Incentive with safety valve
Solar – Large: type	Performance-Based Incentive	Performance-Based Incentive
Solar – Large: Setting	Competitive solicitation	Declining-Block Incentive with safety valve
Geographic distribution	Solar (not NM) incentives vary by EDC but MW are a statewide block with ex-post $ reconciliation between EDCs to equalize cost impact	
Differentiation by market sector	Based on SREC-II	
Sized-to-Load Net Metering (rate applicable to billing period roll-forward)	G rate	Current components of retail rate
VNM Credit Structure (applicable to net excess after roll-forward)	W/S rate	Current framework and rates
VNM Project type limitations	n/a	n/a
VNM size limitation	n/a	Keep current
NM Caps	**Variations:** (A-i) No Caps; (A-ii) Current Caps	**Variations:** (B-i) No Caps; (B-ii) Align to match reaching 1,600 MW target
Timing of solar transition	1/1/17	Once 1600 MW reached
Targets and timeline	Set targets ramping up to 2500 by 2025 (proxy for possible 'budget-limited' approach)	2500 MW with no hard timeline; calibrate modeled incentives to match 2500 by 2025 as best possible
Minimum bill	n/a	
Disposition of RECs	Assume RECs minted as Class I and resold into market	

These policy paths were used for the modeling performed in Task 3.

Massachusetts Net Metering and Solar Task Force

Task 5 - Review of Minimum Bill Policies in Other Jurisdictions and Modeling of a Potential Massachusetts Minimum Bill

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Contents

1 Executive Summary

A utility minimum bill policy was proposed in 2014 as part of a legislative package to modify the current Massachusetts net metering policy. Minimum bills have been implemented in a number of U.S. jurisdictions as a mechanism to recover costs from utility customers with either low monthly consumption or onsite generation. These mechanisms have been designed to ensure a minimum customer contribution from all ratepayers and to reduce the potential impacts of customer cross-subsidization. Minimum bills may differ from other bill mechanisms such as customer charges and demand charges in that they can be designed to only impact a limited segment of utility customers, leaving rates and charges for customers who regularly exceed the minimum bill unaltered.

This report reviews the theory behind the minimum bill mechanism, evaluates the impact of minimum bills in other states and models the potential impact of a minimum bill on a representative PV system in Massachusetts. Key findings include:

- Residential minimum bills that have been implemented in other states have, to date, been relatively modest, ranging from $1.77 per month in one California jurisdiction to $25 per month for large customers of one Hawaii utility.
- Minimum bills have been implemented in some of the most robust solar markets in the country, suggesting that these mechanisms, at the rates implemented, are not fundamentally incompatible with PV market growth. Where implemented, these bill provisions have typically preceded solar market expansion, in some cases by several decades.
- Cash flow modeling of a Massachusetts residential PV system shows that the impact of a minimum bill policy will vary significantly based on the size of the PV system relative to the annual load of a home and the minimum bill level.
- Modeling also indicates that fixed minimum bills could have a greater impact on lower consumption utility customers compared to customers with average consumption assuming both are subject to the same minimum bill charge.[83]

The next section of this report discusses the theory behind minimum bill policies and provides background information on how net metering charges are recovered by Massachusetts utilities. The third section of this report reviews minimum bill policies in other U.S. states. Section 4 of this report reviews the results of a cash flow model that examined the impacts of multiple potential minimum bill rates on a representative PV system.

2 Minimum Bill Introduction and Background

Minimum bill policies have recently been discussed in a number of U.S. jurisdictions as a tool for electric utilities to recover costs from customers using the distribution system but with low net consumption. In part spurred by net metering customers with distributed generation that can significantly reduce monthly bills, these policies have been proposed as a mechanism to reduce both utility lost revenue and ratepayer cross-subsidization associated with net metering. Typically, this mechanism has been proposed as an alternative to other fixed cost recovery mechanisms such as increased customer charges.

Minimum bills (sometimes referred to as minimum bill charges, minimum charges, or minimum monthly contributions) as defined by the Regulatory Assistance Project (RAP) are charges that set a billing threshold under which a customer's monthly bill cannot be further reduced through the application of net metering credits or consumption reductions. After

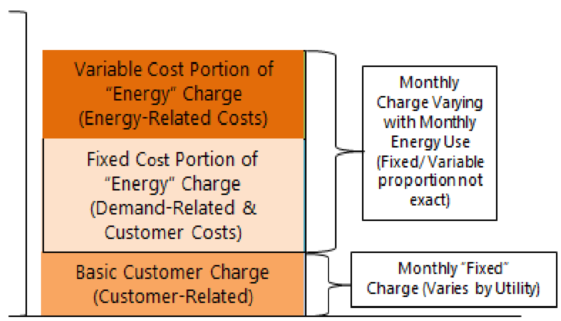
[83] The minimum bill modeled under this analysis was based on minimum bill structures implemented in other states. New and innovative minimum bill designs could be developed in order to address specific concerns related to equity impacts.

establishing a minimum bill threshold, ratepayers whose bills exceed this value see no increased costs or changes in their bill. Ratepayers whose monthly bills are below the minimum bill threshold are required to pay the dollar value of the threshold. This mechanism ensures electric distribution companies a minimum revenue per customer per month (Lazar, 2014). Minimum bills as defined in this report differ from traditional fixed customer charges in that they only affect low usage customers whose monthly consumption is below the minimum bill threshold while other customers whose monthly bills exceed the threshold value see no change in either their monthly bill or the ratio of costs recovered through fixed and volumetric charges. Notably, the use of minimum bills as a potential mechanism to address utility cost recovery issues related to distributed generation is a relatively new area of national discussion and a range of minimum bill structures could potentially be developed including innovative designs that differentiate minimum bill levels based on customer load.

2.1 Net Metering, Volumetric Rates and Utility Cost Recovery

Volumetric rates traditionally have been used to recover both variable costs (e.g., electricity supply) as well as portion of a utility's fixed costs (e.g., distribution system investments) for residential and small commercial customers. Figure 65 below shows a simplified breakdown of cost recovery components for a hypothetical utility residential rate. As the diagram shows, both fixed cost and variable-cost components are recovered through volumetric charges while a smaller portion of the total costs are recovered through fixed monthly customer charges.

Figure 65. Generic Residential Rate Design Example[84]



The recovery of fixed utility costs through volumetric rates (as opposed to demand-based rates or fixed charges) promotes energy conservation while eliminating the need for more advanced metering equipment and complicated rate designs. However, recovering fixed costs through volumetric rates allows low-usage customers to pay less of the fixed cost of service associated with their consumption. This can cause distribution system costs to disproportionately shift from lower-usage ratepayers to the remaining ratepayers (PG&E, 2014). As the number of solar net metering customers increases across the country, public utility commissions, solar advocates, utilities and others are working to balance the benefits and costs of distributed generation in the context of existing volumetric rate designs which can shift fixed distribution system costs to customers without net metered systems.

As a counter to this view, some solar advocates have argued that shifting of utility system costs between ratepayers within a rate class or between rate classes is not unique to net metering and that cost shifts between customer types that further public policy goals have a well-established history of broad-based support. In many states, charges related to energy efficiency, renewable energy and low-income programs shift costs and benefits between participating and non-participating ratepayers. These cost shifts have been deemed acceptable by legislators and regulators as furthering broader public policy goals (Kennerly, Wright, Laurent, Rickerson, & Proudlove, 2014).

In focus group sessions conducted as part of Task 1 some stakeholders expressed the view that current net metering policies created cost shifts between ratepayers that require either new rate structures or the implementation of a

[84] In this figure "Energy" refers to a per kWh charge as opposed to an energy supply charge.

minimum bill policy. Other stakeholders said that new approaches to net metering are not needed and that costs associated with current rate structures are acceptable given the public policy goals that net metering rates support.

In addition to reducing cost shifting between net metering and non-net metering customers, minimum bills can also be used as a mechanism to reduce utility lost revenue due to customer on-site generation. This feature of a minimum bill threshold policy is less relevant in Massachusetts as each of the state's investor owned utilities has existing cost recovery mechanisms that enable recovery of lost revenues associated with net metering.

A minimum monthly contribution mechanism was introduced as part of the draft legislation negotiated between some members of the solar stakeholder community and the Massachusetts investor owned utilities during the final months of the 2014 legislative session. Section 94J of H 4185 defined a minimum bill as:

For all rate classes of each distribution company, the [Department of Public Utilities] shall review and approve a minimum monthly contribution to be included on a customer's total bill that ensures each customer contributes each month a reasonable amount toward the costs of the electric distribution system that are not caused by volumetric consumption. Minimum monthly contributions may differ by rate class and by amount of customer load within each rate class. The [Department of Public Utilities] may exempt or modify the minimum monthly contribution for the low income rate class (Massachusetts General Court, 2014).

Similarly, the proposed legislation included language in the same section that required the minimum bill contribution to be applicable to all customers within a rate class regardless of whether or not they owned renewable energy facilities:

The [Department of Public Utilities] shall ensure that any minimum monthly contributions approved in a revenue neutral rate design filing are applied in a nondiscriminatory manner so that customers with renewable energy generating facilities are subject to the same monthly contributions as customers who do not have onsite renewable energy generating facilities (Massachusetts General Court, 2014).

2.2 Minimum Bills vs. Increased Customer Charges

One potential mechanism to reduce cost shifts associated with low-demand customers and volumetric rates is to increase fixed monthly customer charges while lowering volumetric charges in a revenue neutral fashion. This approach would allow utilities to recover their fixed distribution system costs through fixed rates that are likely better aligned with the costs of serving customers than variable rates. There are, however, several potential drawbacks to this approach that run counter to well established public policy goals. For instance, reducing volumetric charges while increasing fixed charges reduces a customer's economic incentive to conserve energy, and so may drive increased energy consumption (Lazar, 2014). Additionally, increasing traditional fixed charges that apply to all customers within a rate class will likely disproportionately impact low-use, lower income customers (CPUC, 2014).

Alternatively, minimum bills overcome one of these challenges by leaving volumetric kWh prices unaltered, while increasing charges on a small subset of ratepayers whose consumption does not meet the minimum bill threshold. This mechanism may, however, result in bill increases for low income customers with limited electricity consumption. For this reason, establishing a minimum bill threshold that does not create unintended adverse effects for low income customers may require careful consideration of the appropriate rates or specific exemptions for those customers.

Adapted from methodology found in Lazar 2014, Table 1 below shows the total cost for different customer consumption levels for three hypothetical rate structures. The first scenario in the table is a reference case with a low customer charge and higher kWh electricity charge. The second scenario illustrates an increased customer charge applied to all ratepayers with a reduced per kWh charge. The third example is a minimum bill charge set at $20 per month with a small reduction in per kWh charges. For each of these cases, the total costs recovered from customers is identical.

Table 68. Comparison of residential fixed cost recovery scenarios[85]

	kWh Consumption	Low Customer Charge	High Customer Charge	Minimum Bill Charge
Customer Charge		$5	$20	$5
Minimum Bill				$20
Per-kWh Charge		$0.10	$0.0802	$0.096
Customer Consumption	10	$6.00	$20.80	$20.00
	100	$15.00	$28.02	$20.00
	200	$25.00	$36.05	$24.27
	500	$55.00	$60.11	$53.17
	1,000	$105.00	$100.23	$101.35
	1,500	$155.00	$140.34	$149.52
	2,000	$205.00	$180.45	$197.69
Total Costs Recovered		**$566.00**	**$566.00**	**$566.00**

Under the high customer charge scenario, all customers in the low consumption tiers pay higher monthly bills while high-use customers pay substantially lower monthly bills. Under the minimum bill scenario, monthly bills for customers with the lowest usage increase compared to the low customer charge case, but other customers see a modest cost reduction resulting from slightly reduced volumetric charges. This example illustrates how a minimum bill mechanism can be applied to increase cost recovery from very low consumption consumers without increasing costs for other customers or significantly reducing volumetric charges. This case also illustrates the challenge of calibrating a minimum bill threshold so as not to unduly impact low income customers. In the example, the two lowest-tier consumption customers (10kWh and 100kWh)[86] see higher bills under the minimum bill scenario compared to the reference scenario, but the third lowest consumption tier (200kWh) sees a slight bill reduction compared to the reference case.

2.3 Net Metering in Massachusetts

In Massachusetts, customer generators have the ability to reduce their utility bills either through installation of on-site generators or through the application of net metering credits from off-site generators (aka., virtual net metering). Net metering credits applied to customer bills can reduce utility bills significantly and customers have the ability to roll over the monetary value of excess credits for use in future billing periods. These bill credits can be used to offset all bill charges including demand charges, customer charges and other costs, allowing customers to pay their entire monthly bills through the application of net metering credits (Massachusetts DOER).

Investor owned utilities (IOUs) in Massachusetts recover their allowed base revenue, including lost revenue associated with customer net metering (for both on-site net metering and virtual net metering) through either a Revenue Decoupling Mechanism (RDM) or through a Net Metering Recovery Surcharge (NMRS).[87] RDMs establish a fixed annual

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[85] Adapted from Lazar 2014. The numbers in this example are for illustrative purposes only and may not be reflective of specific conditions in Massachusetts.

[86] For reference, the average National Grid residential customers uses around 600 kWh per month. Few customers are likely to have consumption in the 10 to 100 kWh per month range.

[87] Unitil, WMECO and NSTAR recover net metering-related revenues through a NMRS, while National Grid recovers its net-metering related lost revenue through its RDM. WMECO, National Grid, and Unitil are decoupled, and therefore recover their annual target revenue on a reconciling basis; these companies are therefore not negatively impacted by lost sales from increased distributed generation. Currently, NSTAR Electric is not decoupled, and so does not recover lost distribution revenue from reduced sales due to increased distributed generation.

revenue requirement for a utility and allow the utility to recover those revenues through an adjusting per kWh charge that increases or decreases with changes in customer consumption and other factors.[88] This mechanism is intended to make utilities indifferent to the customer activities that may either increase or reduce consumption such as energy conservation measure installation, on-site generation or electric vehicle adoption. Recovery of net-metering related lost revenue is one of many components associated with this charge. NMRSs are a more proscribed charge that allows a utility to recover lost revenue and other costs associated with providing net metering service through an incremental charge on all kWh sales in their territory. In Massachusetts, both these revenue recovery mechanisms are regulated by the DPU and reconciled on an annual basis. National Grid currently uses a RDM mechanism to recover its net metering associated lost revenues. WMECO and Unitil use a combination of NMRSs and RDMs to recover their net metering costs and lost revenues. NSTAR exclusively uses an NMRS for net metering cost recovery.

Over the past several years, as more customers have taken advantage of net metering, these RDM and NMRS charges have increased to allow utilities to recover the increasing loss of revenue associated with distributed generation growth. Table 2 below shows the most recent effective NMRS and RDMs for residential customers of the Massachusetts investor owned utilities. Total aggregate distribution charges are listed as well for reference. As noted above, net metering associated costs contribute to RDM charges, however RDMs are structured to recover costs from a much broader range of utility activities than just net metering.

Table 69. Current NMRS and RDM rates for Massachusetts IOUs[89]

Utility Territory	Current Residential NMRS per kWh	Current Residential RDM per kWh	Current Total Residential Distribution Charge (First Block) per kWh
Eversource - Western Mass Electric Company	$0.00172	$(0.00280)	$0.04006
Fitchburg Gas & Electric (d/b/a Unitil)	$0.00199	$0.00638	$0.11220
Eversource – NSTAR BECO	$0.00200	N/A	$0.08287
Eversource – NSTAR Cambridge Electric	$0.00360	N/A	$0.08196
Eversource – NSTAR Commonwealth Electric	$0.00199	N/A	$ 0.09280
National Grid	N/A	$0.00069[90]	$0.07161

These revenue recovery mechanisms protect Massachusetts utilities from lost revenues associated with net metering, eliminating one barrier to wider adoption of customer-sited generation. Under its current structure, net metering does, however, create distributional effects between net metering customers and non-net metering customers. For instance, as part of its 2015 NMRS request, NSTAR requested to recover $30.8 million in costs associated with net metering. As per NSTAR's net metering tariff, this value includes:

(1) The value of any net metering credits paid to customers the previous year;
(2) Lost distribution revenue associated with on-site power consumption by net metered customers;
(3) The total amount under-recovered costs during the previous year under the NMRS mechanism.

These costs are reduced by revenues received by NSTAR for power sold into the ISO-NE market from Class II and III net metering generators.

[88] NMRSs can also be used to provide credits back to customers in the event utilities over-recover their costs in a given year.
[89] (WMECO, 2015), (Unitil, 2015), (National Grid, 2014)
[90] This rate includes a portion of National Grid's Capital Expense tracker, the reconciliation of the prior year's RDM balance, along with any effects on billed revenue from the economy and/or weather, which is more than simply lost revenue and net metering credits for the prior calendar year.

Recent filings by National Grid as part of their annual RDM filings indicated that $40.1 million in net metering credits were provided to customers in 2014 while $12.2 million was recovered through sales of electricity to ISO-NE from Class II and Class II net metered generators. As of this writing, the cost associated with lost distribution revenues from displaced customer consumption has not been published (National Grid, 2015).

Recovery of these charges represents a cost to non-participating ratepayers and a benefit to customer generators. Under these cost/revenue recovery models, as participation in net metering increases over time, the shift in costs associated with net metering will increase.

Some analysts have argued in other states that net metered customers provide additional benefits to the utility system that benefit non-participating customers and that are not monetized in simplified net metering cost recovery frameworks. Potential benefits that are not accounted for in the Massachusetts NMRS model could include avoided transmission and distribution investments. If these avoided utility costs were integrated into the NMRS cost recovery framework, total recoverable net metering costs could be lower. In theory and over the long term, the costs avoided by the installation of customer-sited generation are accounted for by a RDM where any avoided costs to the distribution system associated from customer generators would result in lower applicable RDM charges. The total net change in a RDM charge due to integration of customer-sited generation, however, would include a range of both costs and benefits, meaning the net effect on these charges could be either an increase or a decrease in rates depending on the magnitude of the applicable system costs and benefits.

3 Minimum Bill Policies in Other States

A number of other states have either implemented or are actively exploring implementing minimum bill mechanisms. To date, the policies that have been implemented have included relatively modest minimum bills, ranging from $1.77 per month in one California utility territory to up to $25 per month in Hawaii.[91] These states have some of the most robust solar markets in the United States, suggesting that minimum bills, as implemented, are not fundamentally incompatible with solar market development. The following section reviews experiences in these and other states.

3.1 Minimum Bill Policies in California

California's investor owned utilities have small, longstanding minimum bill rates. Similarly, several California municipal utilities have implemented minimum bills or have recently increased fixed charges in part as a result of increased customer DG adoption. The following two sections discuss these California utilities.

3.1.1 Current and Future Investor Owned Utility Policies

Pacific Gas & Electric (PG&E), Southern California Edison (SCE) and San Diego Gas & Electric (SDG&E), California's three largest investor-owned utilities have established residential minimum bill policies in place. This alternative to fixed charges was first authorized in a 1981 California Public Utilities Commission (CPUC) ruling (CPUC, 2014). These charges are billed as daily minimum meter charges and are meant to help utilities cover fixed costs for transmission, distribution, billing and metering. The current fee structure for each of that state's IOUs is summarized in Table 70 below.

[91] Task force members have suggested that minimum bills may be higher in vertically integrated utility territories. The limited number of cases reviewed in this report do not allow for a definitive conclusion to be reached on this question.

Table 70. California IOU Minimum Bill Charge Structures[92]

Utility	Minimum Charge ($/meter/day)	Total Monthly (30-days)
PG&E	$0.14784	$4.435
SDG&E	$ 0.170	$5.10
SCE[93]	$0.059	$1.77

Some California utilities additionally provide separate, reduced minimum bill charges for qualifying low-income customers as well as separate rates for multi-family residences. Given the longstanding nature of these minimum charges and their relatively modest rates, and the fact that California has been a leading solar state for many years, it is unlikely that these minimum bill mechanisms have significantly impacted the growth of customer-sited generation in California.

In October 2013, the California legislature passed Assembly Bill 327 (AB 327) which has a number of implications for the future of the state's solar market development and net metering programs. The bill marked the start of a regulatory reform process by removing restrictions which had previously limited changes to residential rates. This shift was motivated by inequities and cost shifts in the existing rate structure. AB 327 requires the state's current net metering program to end by July 1, 2017 or when investor owned utilities (IOUs) reach their existing program caps. Existing net metered generators would continue to receive net metering credits at the retail rate under the current program for the useful life of their system. However, new generators will be required to use a new uncapped net metering program which will be designed through a CPUC processes. The CPUC is expected to announce the details of the revised net metering program, which will feature a standard contract, before 2016. Additionally, AB 327 allows for utilities to file for new rate design proposals including fixed charges or minimum bills capped at $10/customer (CPUC, 2014).

During the stakeholder process that resulted in the CPUC's residential rate design recommendations, a number of stakeholders made arguments for and against minimum bill policies. For instance, utility stakeholders argued that fixed charges were superior to minimum bill programs as they better reflect cost causation principles that ensure fairness amongst ratepayers. Similarly, utility stakeholders argued that allowing distributed generators to avoid fixed customer charges amounted to an arbitrarily set incentive. Additionally, stakeholders in favor of fixed charges argued that these mechanisms did not necessarily reduce customer incentives to invest in energy efficiency and that volumetric charges set to recover fixed utility costs may lead to customer energy efficiency investments that were not cost effective from the societal perspective. Proponents of minimum bills argued that these mechanisms have the benefit of reducing free ridership without altering the economic incentive for most customers to invest in energy efficiency (CPUC, 2014).

In the CPUC's *Staff Proposal for Residential Rate Structure*, the CPUC stated that a minimum bill could be considered as an alternative to a fixed charge for utilities if the minimum bill was initially capped at $10/month per customer and $5/month for low-income customers. Any minimum bill rate could adjust with inflation over time. The CPUC agreed with commenters that a minimum bill would prevent free ridership from zero or low-consumption customers, and not unduly penalize other ratepayers (CPUC, 2014). In the case of either a fixed charge or minimum bill thresholds, the Commission would require that the charge reflect the cost of service for customer classes, prevent significant erosion of incentives for conservation, and minimize burdens on low-income customers. The CPUC will begin to consider new fixed charges or minimum bills this year as utilities make revised residential rate proposals.

3.1.2 California Municipal Utility Programs

In addition to the IOU minimum bill programs, two municipal utilities, Sacramento Municipal Utility District (SMUD) and the Los Angeles Department of Water and Power (LADWP) have existing fixed charge or minimum bill policies in place that establish non-zero minimum monthly contributions. Both SMUD and LADWP have a significant penetration of net

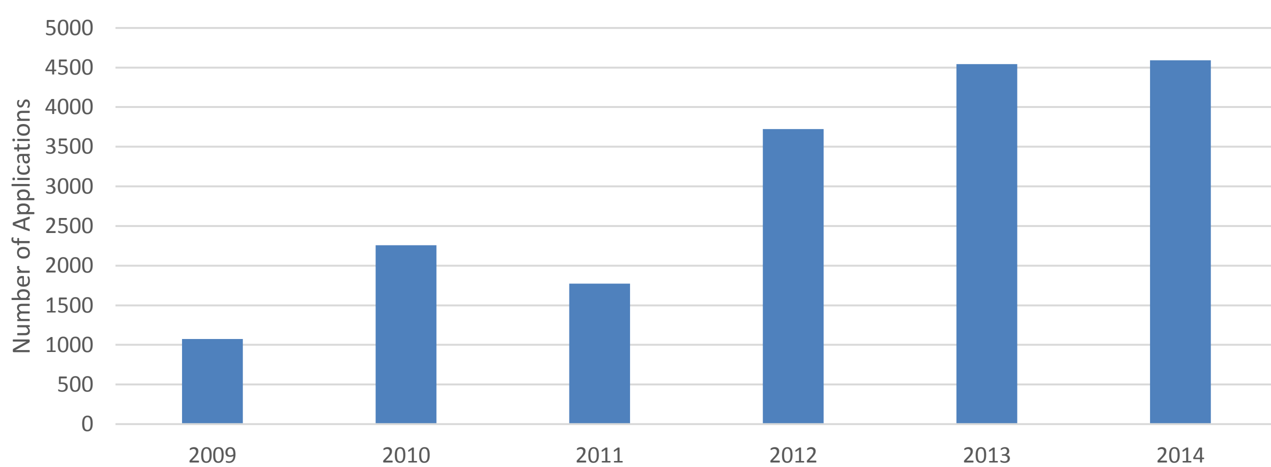
[92] (PG&E, 2015), (SDG&E, 2015), (SCE, 2014), (SCE, 2014)
[93] SCE has a separate minimum bill rate for multi-family residential customers of $0.044 $/meter/day.

metering customers, with LADWP having over 12,000 installations as of April 2014 (LADWP, 2014). The details of their programs are discussed below.

Los Angeles Department of Water and Power (LADWP)

As part of its strategy to stabilize revenues, LADWP began a rate reform process in 2008, which included revenue decoupling (City of Los Angeles, 2012). As part of this process, LADWP instituted a minimum charge for some residential customer rates (City of Los Angeles, 2012). Los Angeles has one of the most robust municipal solar markets in the United States and, as of July 2014, had the most net energy metering customers of any municipal utility in the country with over 12,000 installations (LADWP, 2014). LADWP has offered solar incentives since 1999, and currently offers a declining block incentive program for its customers (LADWP, 2015). LADWP's net metering program credits excess generation at the retail rate, though the utility has proposed studying other policy alternatives before the current program ends in December 2016 (LADWP, 2014). Solar systems up to 1MW can qualify for the program and virtual net metering is not allowed under current net metering rules. Net metering credits cannot be used to reduce a customer's bill below the minimum charge (DSIRE, 2014). Thus, if a customer is low or zero usage, they still have to pay the minimum charge associated with their rate class. For residential customers using Standard Residential Rate (R1-A), this charge is currently $10. This $10 minimum bill has been in effect since at least 2009. Figure 66 below shows the annual applications from the LADWP solar program from 2009 to 2015. During this period, solar installations in LADWP's utility territory have grown substantially, suggesting this minimum bill mechanism has not been a substantial barrier to market growth during this period.

Figure 66. Applications for LADWP Solar Incentive Program 2009-2014



LADWP has proposed additional rate reforms to unbundle residential rates into generation, distribution and transmission components so that net metering credits can be applied to the most appropriate portion of customer bills. This was proposed in order to prevent further cost-shifts after the net metering program expands beyond the current 310MW cap.

Sacramento Municipal Utility District (SMUD)

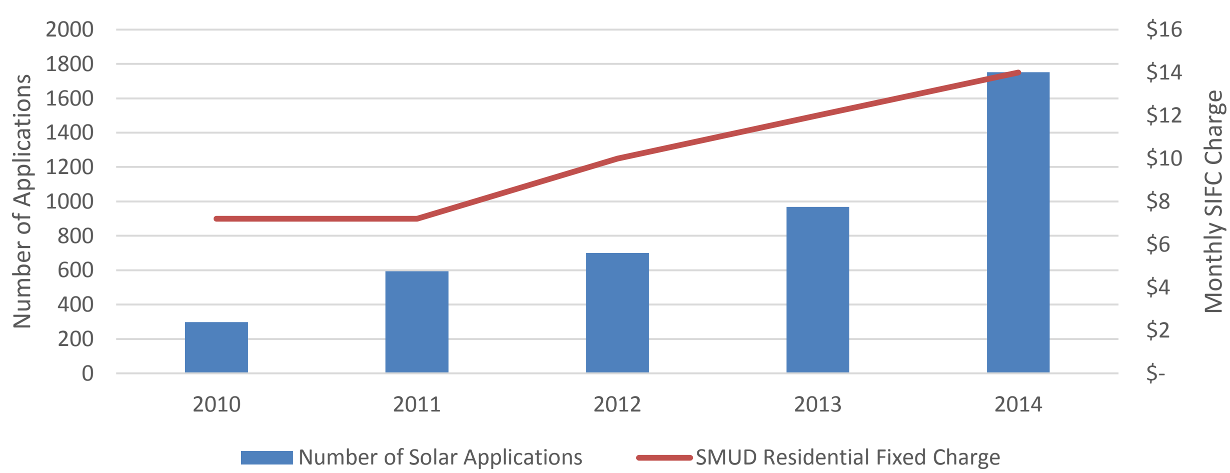
SMUD installed the nation's first utility scale solar system in 1984, and has remained supportive of solar energy development. The municipal utility offers net energy metering for distributed generators up to 1 MW in size, and a community solar program called Solar Shares. SMUD compensates excess generation at the retail rate and exempts distributed generators from standby charges (SMUD, 2010). SMUD also provided a feed-in-tariff for solar energy until the program reached capacity in 2010. Residential systems now qualify for a $500 upfront payment incentive. As of January 2015, SMUD had processed over 5,000 applications for its incentive programs (SMUD, 2015).

During a recent review of its rates, SMUD found that 75 percent of residential customers were not paying their full cost of service. The utility is currently undergoing a residential rate reform process to allow rates to more accurately reflect cost of service. SMUD intends to shift entirely to time-of-use residential rates by 2017, and is undergoing a process to reduce its tiered residential rate system.

In addition to rate reform, SMUD began increasing its System Infrastructure Fixed Charge (SIFC) in 2012 in order to help recover the fixed costs of serving utility customers. These increased fixed charges were matched with reductions in volumetric kWh charges. SMUD's board approved these changes to more closely align with the cost to serve each customer. This charge is assessed on all bills and is set to escalate to $20 for residential customers by 2017 to cover 100 percent of customer and distribution costs. The current residential fixed charge has risen to $16 from $7.20 per customer in 2011. As a fixed charge, the SMUD SIFC is not a minimum bill policy as defined in this report as the charge, when implemented, led to a rate increase for all customers regardless of consumption. However, like a minimum bill, the SIFC cannot be avoided through net metering credits or conservation (SMUD, 2015).

Despite not being structured as a minimum bill, this rate mechanism can provide some limited insight into the potential effects of a minimum bill policy on solar market development. SMUD's fixed charge has increased gradually since 2012 for all rate classes. Despite this, SMUD has continued to see a growth in applications for its solar program. Figure 67 below shows the annual number of residential solar program applications between 2010 and 2014 along with the applicable residential SIFC charge. As the figure shows, the number of solar program applications continued to grow as the charge increased, suggesting that the charge has not been a significant barrier to local solar market growth. Notably, this simplified analysis does not take into account changes to solar installed costs over this time period or reductions in SMUD incentives which likely have more significant influences on solar market growth rates.

Figure 67. SMUD PV Program Applications and SIFC Charge Rates 2010-2014



3.2 Minimum Bills in Hawaii

Hawaii has one electric holding company (collectively known as the HECO Companies) that serves three separate utility territories, Hawaii Electric Company (HECO), Maui Electric Company (MECO), and Hawaii Electric Light Company (HELCO). The state has the highest per-capita solar penetration in the United States, with more than 10 percent of residential customers having PV installations in some utility territories (Wesoff, 2014). Driven by high fuel costs, electricity prices in Hawaii are some of the highest in the nation, with average residential electricity prices ranging between \$0.39 and \$0.46 per kWh in 2013 (HECO, 2014). Hawaii has had robust utility solar incentives over the past decade, with Hawaii utilities offering both a feed-in tariff program and net metering (HECO, 2014).

Each of Hawaii's IOU territories includes minimum charges in each of their tariff rates. These charges have been in place since before the development of the state's solar PV market. For residential customers, minimum charges are in addition to the monthly customer charges and must be paid in the event that customer consumption drops below the minimum charge threshold. Customers that exceed the monthly minimum bill are not subject to any additional monthly charges as a result of this mechanism. Table 4 below shows the current minimum charges for each of the three Hawaii IOU territories for the residential rate.

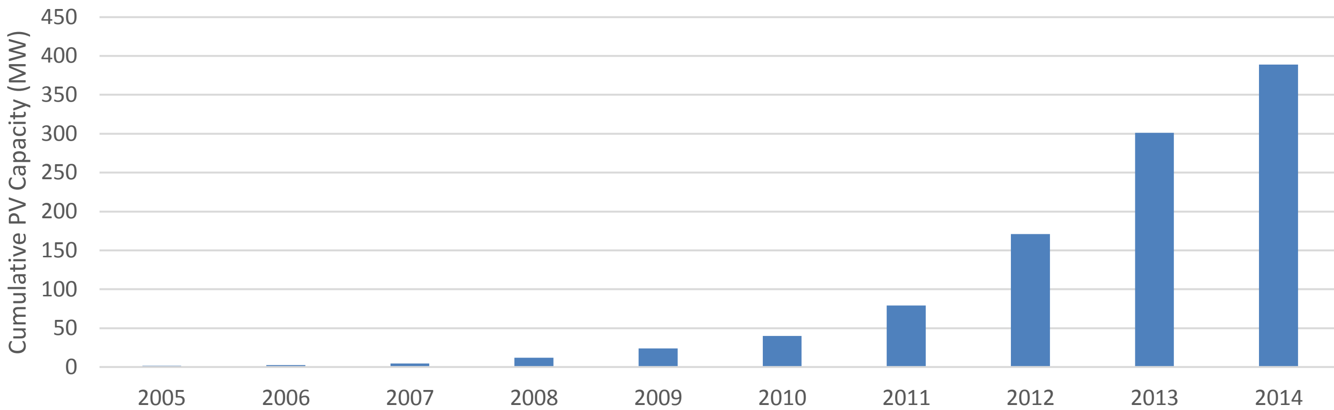
Table 71. Residential Minimum Charges for Hawaii IOU Territories (HECO, 2014)

	Single Phase Minimum Charge per Month	Three-phase Minimum Charge per Month
Hawaii Electric Co. (HECO)	\$17.00	\$23.00
Hawaii Electric Light Co. (HELCO)	\$20.50	\$25.00
Maui Electric Co. (MECO)	\$18.00	\$22.50

Minimum charges for demand metered customers are defined as the sum of the customer charge and any applicable demand charges. Because these minimum charges for demand metered customers are effectively the same as the charges that would be paid by any customer in the rate class regardless of consumption, they are fundamentally different from the minimum charge structure that is applied to residential rates. This minimum charge structure effectively ensures that standard demand charges cannot be bypassed through conservation or net metering.

Hawaii has seen robust solar market growth over the past several years. Figure 4 shows the cumulative PV capacity in the HECO Company territories between 2005 and 2014. Given this aggressive market growth, the relatively high minimum bill charges applied to distributed generation customers do not appear to have created a significant barrier to solar market development. Critically, these relatively high minimum charges are being applied in a market with substantially higher retail electricity prices than seen in mainland U.S. utility territories, potentially mitigating any effects of the charges on solar market development.

Figure 68. Cumulative PV Capacity in MW in HECO Company Territories (HECO, 2015)



In January 2015, the HECO Companies submitted a request to the Hawaii Public Utility Commission for approval of a Transitional Distributed Generation Plan as part of ongoing efforts to reform the utility business model in the state to increase renewable energy generation. The transitional plan recommended significant changes to the existing net metering framework, including transitioning from full retail rate net metering to generation payment rates set equal to the utility's avoided fuel cost. This proposal has received a significant negative response from the solar stakeholder community in Hawaii and is currently the subject of ongoing regulatory consideration. At the same time, Hawaii's IOUs have proposed, as part of the state's broader renewable energy transition process, to move towards a rate structure with higher minimum charges and lower volumetric rates. The HECO Company's initial filing proposed illustrative minimum residential charges of $55 for customers without on-site generation and $71 for customers with on-site generation. In the example offered, these higher minimum charges would be offset by lowering electricity rates from $0.34 per kWh to $0.26 per kWh for residential customers (HECO, 2014). The final outcome of this reform proposal is currently pending.

3.3 Ongoing Net Metering Cost Recovery Discussions in Other States

Discussions about the future of net metering and the potential applicability of minimum bills are ongoing in a number of states. The following section provides background information on several of these state-level policy discussions.

3.3.1 Arizona

In 2013, Arizona Public Service (APS) went before the Arizona Corporation Commission (ACC) with two proposals to address ratepayer cost-shifting resulting from their existing net metering program. In support of this request, APS indicated that it received an average of 500 net metering applications per month and estimated that each system resulted in $800-$1,000 in added costs to non-ratepayers annually (Arizona Corporate Commission, 2013). As part of the regulatory proceedings, solar advocates submitted a study which concluded that the benefits of DG systems exceeded the costs and argued that net metering under-compensated DG generators (Arizona Corporate Commission, 2013). APS proposed transitioning net metering customers to time of use rates with demand charges or shifting DG customers to a buy-all, sell-all approach to address these costs.[94] APS's proposed demand charges under either of the existing residential rate structures significantly eroded savings for net metering customers (Arizona Corporate Commission, 2013). Several protests were filed which stated the APS analysis excluded the benefits of DG, and that such changes were more appropriately addressed by a rate case.

[94] Under a buy-all, sell-all approach, distributed generation owners sell the entirety of the generation of their system to the grid, using no self-generated power on site.

The ACC noted that existing studies of the value of DG were inconclusive and that imposition of demand charges or a tariff approach for DG customers would be more appropriately addressed in a rate case. The ACC rejected both of APS's proposals in favor of an interim adjustment to APS's Lost Fixed Cost Recovery Mechanism of $.70/kW, resulting in a revenue neutral charge for all new systems installed after December 31, 2013. Existing generators would not be subject to any changes until after APS's next rate case in 2015 (Kennerly, Wright, Laurent, Rickerson, & Proudlove, 2014).

In addition to the APS rate design discussions, the Salt River Project (SRP), an Arizona public power provider, has recently approved a new demand charge on solar customers as part of a broader rate restructuring effort. Reports have indicated that this new solar demand charge could increase residential solar customer's bills by $50 per month. SolarCity, a national solar installation company with a significant presence in Arizona, has filed a lawsuit in an effort to block implementation of the new solar demand charge (Pyper, 2015).

3.3.2 Kansas

In 2014, Kansas legislators voted to continue the state's net metering program with modifications. House Bill 2101 allowed utilities to submit proposals to the Kansas Corporation Commission on minimum bills, time of use rates or other rate structures for DG after July 1, 2014 (Legislature of the State of Kansas, 2014). As of yet, however, Kansas' IOUs have not proposed a minimum bill or other cost recovery mechanism to the Commission. The bill also reduced the eligible system size for net metering. Residential size caps decreased from 25 to 15 kW, commercial systems sizes dropped from 200 to 100 kW and non-profit or public sector systems are now capped at 150 kW. The bill also reduced the credit for excess generation from the retail rate to avoided costs. Systems installed prior to July 1st, 2014 are grandfathered under the current program until 2030. In April 2014, Kansas had approximately 200 net-metered systems. The bill was considered a compromise in Kansas since the original proposal would have eliminated the state's net metering program (Uhlenhuth, 2014).

3.3.3 Oklahoma

In April 2014, the Oklahoma legislature passed Senate Bill 1456 which was designed to prevent the cross-subsidization of distributed generators by other ratepayers. The law enables utilities to impose fixed charges solely on DG customers in a rate class as long as the charge is justified. Utilities are allowed to submit proposed tariffs to the Oklahoma Corporation Commission (OCC) by the end of 2015 (Oklahoma Senate, 2014). The law was later clarified via an Executive Order in July 2014. The Executive Order stated that the OCC could consider alternative policy choices, such as minimum bills, time of use rates and demand charges before implementing fixed charges. At present, no tariffs have been proposed to the OCC. As of July 2014, Oklahoma IOUs had approximately 350 DG customers (Oklahoma Secretary of State, 2014).

3.3.4 Texas

The Texas Public Utility Commission allows Retail Electricity Providers (REPs)[95] to assess minimum or low usage charges on customers with low consumption (Public Utility Commission of Texas, 2014). This threshold is defined by each REP. A study by the Texas Ratepayers' Organization to Save Energy documented that the number of Texas retail electricity providers assessing minimum usage fees grew from 36% to 81% between 2011 and 2013. In most cases, the usage fees trigger when customers use 1,000 kWh or less of electricity and range in price from $6-$20. These fees tend to be disclosed in the terms of service for each provider (Biedrzychi, 2013). The cumulative capacity of solar installations in the state grew by 307% between 2011 and 2013, however a limited portion of this growth was behind the meter systems (IREC, 2014). Texas does not currently have a statewide net metering policy. Given the significant difference in the local solar market and electricity service delivery market structures between Texas and Massachusetts, direct comparisons between the states is difficult.

[95] Texas has transitioned to a retail electric competition model under which REPs provide service through regulated Transmission and Distribution Utilities (TDUs) allowing REPs them to offer full service electric generation, transmission and distribution services for retail customers (Public Utility Commission of Texas, 2014).

4 Minimum Bill Modeling

In order to explore the dynamics of a potential minimum bill both on individual customer utility charges and PV system economics, a simplified PV system cash flow model was developed. To isolate the potential impacts of a minimum bill policy and evaluate a range of policy and system parameters, modeling was conducted on a representative residential PV system. A series of sensitivity analyses were conducted to explore how different minimum bill levels might lead to different project cash flow parameters and utility charges. Modeling outputs included total utility charges recovered, simple payback and internal rate of return (IRR). The following sections review the assumptions and results of this modeling exercise. Critically, the results of this section are specific to the system type modeled and the assumptions used. The production, economics and on-site load parameters are unique for each PV system in Massachusetts, with no two systems being alike. The results found in this section were developed with the intent of informing the Massachusetts net metering task force regarding the dynamics of a potential minimum bill policy. This is not intended as a minimum bill rate setting exercise or as a conclusive exploration of the merits of a minimum bill policy over other potential policy mechanisms.

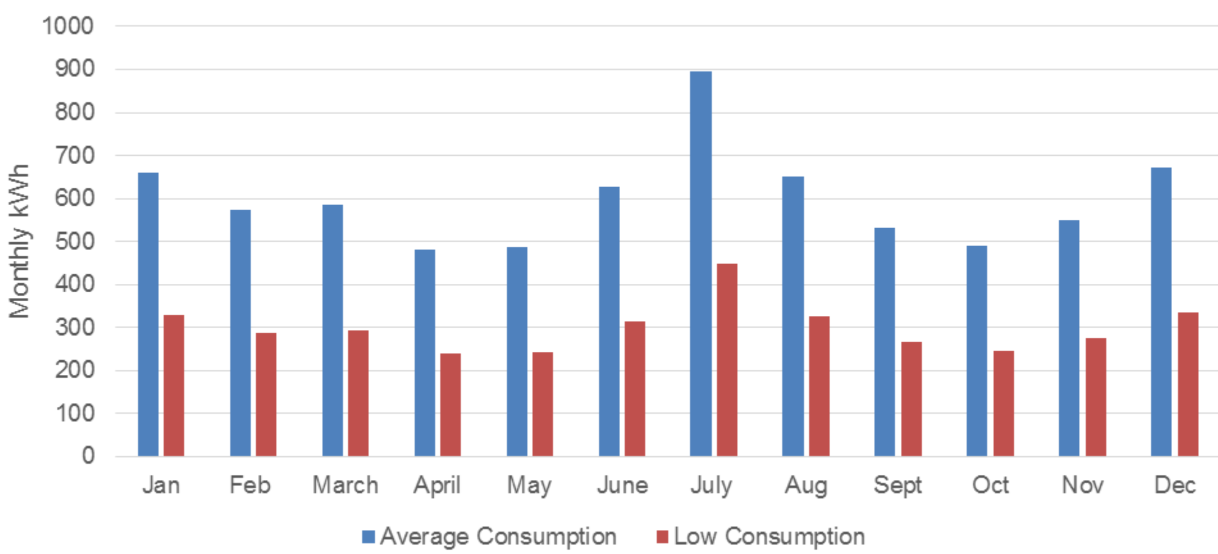
4.1 Modeling Parameters

The following section describes the major modeling parameters used to evaluate the potential effects of a minimum bill on utility costs recovery and PV system economics.

4.1.1 Onsite Load

The National Grid basic service R-1 hourly load data from 2013 was used as the modeled home electricity consumption under this task (National Grid, 2015). This system-wide hourly load curve data was normalized on a percentage basis and scaled to create two hourly annual load curves, one for a home using an average of 600 kWh per month ("Average Consumption") and another for a home using an average of 300 kWh per month ("Low Consumption"). This corresponds to an average National Grid residential customer and a low-usage customer. These scaled hourly load profiles were transformed to create monthly load profiles for each of the two load cases. Figure 69 below shows the two monthly electricity consumption profiles used in the modeling.

Figure 69. Modeled Monthly Consumption Profiles



4.1.2 PV System Parameters

The modeled system was assumed to have a 20-year life. PV system parameters were adjusted National Renewable Energy Laboratory's PVWatts program to develop a monthly kWh production profile for a residential PV system that aligned with historic Massachusetts PV system production (DOER, 2015). Solar insolation data from Worcester, Mass. was selected for developing the production profile. Table 72 below shows the default PVWatts parameters while Figure 70 below shows the monthly PV production profile for a representative 1kW system.

Table 72. PV System Modeled Parameters

PV System Assumptions		
Production Profile	PV Watts Standard Assumptions for Worcester, MA	
Array Tilt	35	Deg
Array Azimuth	190	Deg
System Losses	24%	Percent
Inverter Efficiency	96%	Percent
DC to AC Size Ratio	1.1	
System Degradation	0.50%	Percent per year
Annual production	1,180	kWh/kW

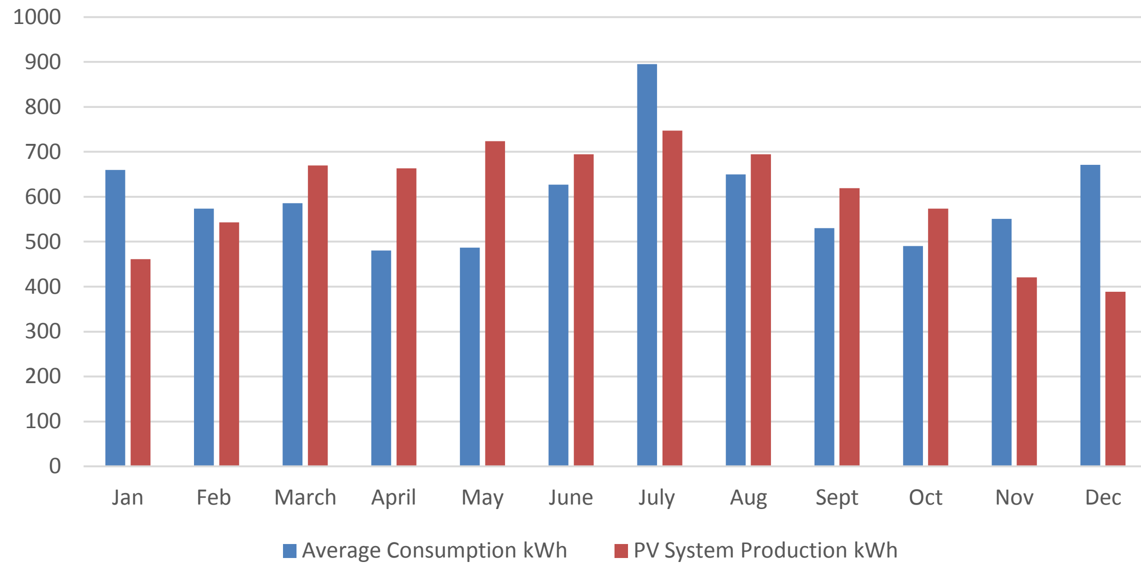
For the minimum bill analysis, a range of system sizes were used to evaluate the potential effects of differing minimum bill levels on multiple PV system sizes. For the analysis, four system sizes were evaluated for each of the two representative home load cases. These system sizes were modeled to cover 120%, 100%, 80% and 60% of a homeowner's annual load. Table 73 below shows the system sizes modeled for each of the site annual consumption cases.

Table 73. PV System Sizes Modeled

PV Production to Annual Consumption Ratio	Average Consumption Case	Low Consumption Case
120%	7.32 kW	3.66 kW
100%	6.10 kW	3.05 kW
80%	4.88 kW	2.44 kW
60%	3.66 kW	1.83 kW

Table 72 below shows the monthly PV system production profile for a 6.1 kW system with the annual load profile for the average home load case. Under this scenario, the PV system provides 100 percent of the annualized electricity consumption.

Figure 70. 6.1 kW PV System Monthly Production and Average Consumption Monthly Profile



4.1.3 Financial Assumptions

Across Massachusetts, there is significant variation in PV system ownership models and financing structures. In order to best isolate the potential effects of a minimum bill on PV system economics and eliminate potential confounding effects related to system economic financing assumptions, the modeled systems in this analysis assumed a cash purchase by the homeowner. While this assumption represents only one of many potential ownership and financing models currently used in Massachusetts, and may not represent the majority of residential PV systems currently in the marketplace, it was chosen as a simplifying assumption that would allow for a more straightforward exploration of a minimum bill on the dynamics of PV system economics. As such, the investment return values presented as outputs to this analysis may not be representative of typical returns currently seen for PV system in Massachusetts.

In order to model a range of potential system paybacks and investment returns, three cost cases were modeled. Individual cases were examined assuming $3, $4 and $5 per watt system installation costs. This represents a broad range of potential system costs that is representative of the range of system prices reported in the latest DOER SREC II public dataset. One assumption that was made in order to simplify the analysis is that PV system costs do not benefit from economies of scale. A homeowner purchasing a 7.3 kW system may be able to benefit from a lower per watt price than the same homeowner purchasing a 3.7 kW system. This effect was not modeled and would tend to improve the economics of larger systems relative to smaller systems in the analysis.

4.1.4 Utility Bill Parameters

Modeled utility bill parameters were based on National Grid R-1 distribution rates (National Grid, 2015). Distribution rates for net metering credits from exported power do not include the energy efficiency and renewable energy charges per current statute, regulations and tariffs. Separate basic service supply rates were modeled for winter periods (November through April) and summer periods (May through October). Basic service rates for summer and winter periods were based on the average basic service rates for those periods over the last five years. A five-year average was chosen instead of the most recent year basic service rates in order to lessen the effects of recent high winter basic service rates on modeling. Additionally, a $4 customer charge was applied to each monthly period modeled. All utility bill elements were escalated throughout the analysis at a 1.89% annual rate.

Table 74. Electricity Bill Component Parameters

Electricity Value of Production and Utility Bill Components		
Starting Customer Charge	$4.00	National Grid R-1 Customer Charge
Starting Distribution Rate for On-site Consumption	$0.07426 $0.08008	National Grid R-1 Distribution Rates[96]
Starting Distribution Rate for Monthly Exported Power	$0.0611	National Grid R-1 Distribution Rate minus EE and RE Charges
Staring Basic Service Supply Summer (May - October)	$0.0753	Average of last five years[97]
Starting Basic Service Supply Winter (Nov - April)	$0.0999	Average of last five years[98]
Utility Bill Escalation Factor	1.89%	Annual Escalator for All Bill Components[99]

4.1.5 Minimum Bill Parameters

Four minimum bill cases were modeled: $4, $10, $25 and $50.[100] These values were selected for the sole purpose of providing a sensitivity analysis of the potential impacts of a minimum bill and do not represent suggestions for a Massachusetts minimum bill. Additionally, a base case without a minimum bill was modeled. Like the other bill components, the minimum bill was assumed to escalate yearly at 1.89%. The minimum bill was structured as the non-zero lowest potential bill threshold for each month modeled. During months in which there was a calculated utility bill that exceeded the minimum bill, previously banked net metering credits, if available, were first used to reduce the utility bill, either to the minimum bill threshold or until the banked net metering credits were fully used. Any remaining required utility bill, either at the minimum bill level, or in excess of the minimum bill, was assumed paid by the customer during that month. During months in which the calculated bill based on monthly consumption was below the minimum bill threshold, the utility customer was assumed to pay the minimum bill. The difference between the minimum bill paid and what the bill would have been without the minimum bill was carried forward for use in future months. Additionally, in months in which production resulted in a net export of power, net metering credits were calculated and any excess credits were similarly rolled over into the next monthly period. Minimum bill payments are assumed to be paid to the distribution utility and not passed on to electricity suppliers. From the perspective of the PV system owner, this does not affect project economics. This minimum bill structure was modeled as an example that most closely approximates minimum bills in other states. New minimum bill designs could be developed and implemented in Massachusetts that would have different parameters, and Task force members representing the Massachusetts utilities have suggested that innovative minimum bill structures that are tailored to a customer's load and/or differentiate between on-site and virtual net-metered systems could be a potentially appropriate approach.

4.1.6 Incentive Assumptions

Modeled PV systems were assumed to benefit from both the 30% federal residential renewable energy tax credit and the Massachusetts residential renewable energy income tax credit. Both these tax incentives were assumed to be fully monetized in April during the year after the installation of the system. Additionally, the modeled system benefited from SREC revenues over the first ten years of the system life. SRECs were assumed to be monetized at the SREC auction price floor with payments for 12 months of SRECs occurring once a year after the close of the auction.

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[96] National Grid's R-1 rate is structured as an inclining block structure, with kWh consumption over 600kWh having a different tariff rate than consumption under 600kWh.

[97] (National Grid, 2015)

[98] (National Grid, 2015)

[99] 20-year average residential annual utility cost increase 1994-2013 from (EIA, 2015). Each bill component has different cost drivers and likely escalation (or de-escalation) rates, however determining likely component-by-component cost escalation rates is beyond the scope of this analysis.

[100] These correspond to the current National Grid customer charge and 2.5, 6.25 and 12.5 times the customer charge value respectively.

4.1.7 Other Simplifying Assumptions

In order to isolate the potential effects of a minimum bill, a number of simplifying assumption were made in developing the model. For instance, random annual fluctuations in onsite load or PV system output were not modeled and instead a consistent annual onsite load and PV production pattern was used. Adding annual variations in production and consumption have the effect of altering minimum bill dynamics potentially creating more or less annual net metering credit carryover. Additionally, the model does not include ongoing costs associated with system operations and maintenance or potential future inverter replacement. The modeled system is installed on January 1st of 2015 and different system modeling start dates could affect early-year model outputs, system paybacks and rates of return. This simplified model also assumes that system owners are not monetizing cumulative excess generation through the Schedule Z credit transfer mechanism. The implications of this assumption are discussed later in this section. Finally, all utility bill components are assumed to escalate at the same rate, in reality market conditions and regulatory cases will cause these components to increase (or decrease) at different rates.

This analysis does not examine potential minimum bill dynamics on non-residential utility customers. Given the significant variation in customer loads and rate structures for non-residential utility customers, modeling a representative building that could provide generalized insights to the Task Force would be difficult. Additionally, minimum bills for commercial customers in other jurisdictions have typically been designed as non-bypassable demand charges, making them highly customized to the specific circumstance of each utility customer.[101] This analysis also does not explore other unique residential cases such as seasonal second homes or community shared solar. In particular, the effects of minimum bills on community shared solar customers may be similar to the low-consumption case discussed in this section, although these similarities would likely only apply to certain community shared solar ownership models.

4.2 Modeling Results

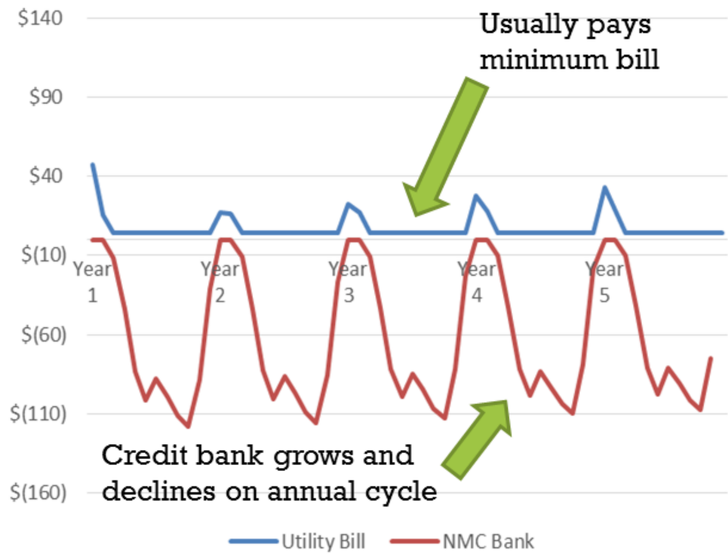
4.2.1 Minimum Bill Dynamics

Each of the modeling parameters were run as part of 40 unique cases. Results showed that combinations of minimum bill levels, relative PV system sizes and total home consumption resulted in three distinct patterns. These three scenarios are illustrated below.

Under one scenario, illustrated in Figure 71 below, PV production leads to excess generation and banking of net metering credits during spring and summer periods. The blue line represents the customer's total utility bill for each month while the red line is the cumulative value of the customer's banked net metering credits. Under this scenario, the customer banks credits during the spring and summer months while credits are used in the late fall and winter months. This banking cycle occurs on an annual cycle and the customer does not build up a bank of credits that are carried forward for multiple years. This credit banking dynamic can result in customers paying the minimum bill during certain period of the year and paying higher bills during period of low PV production when the net metering credit bank has been full expended.

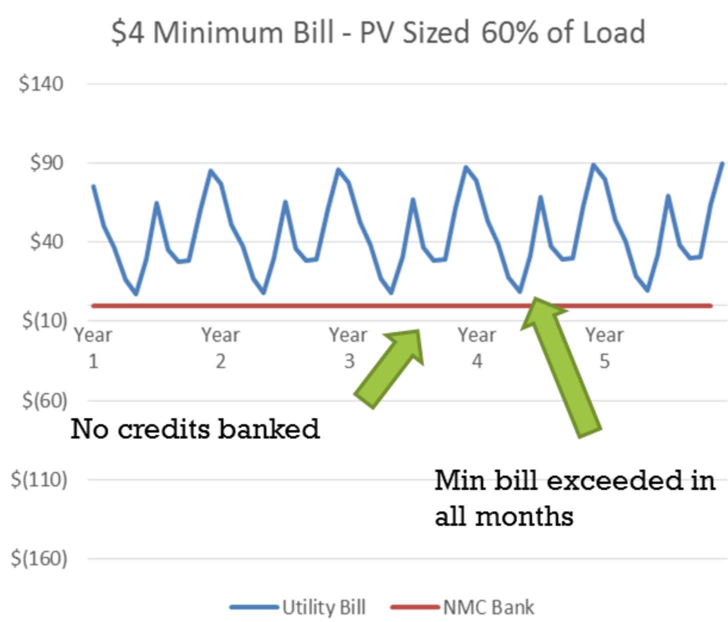
[101] The use of monetarily denominated net metering credits in Massachusetts that can be applied to non-volumetric charges allows commercial customers to reduce demand-related portions of their utility bills. Some states do not have similar net metering structures, and instead denominate net metering credits volumetrically, making commercial minimum bills in those states less relevant, as customers under those circumstances cannot avoid demand charges through net metering.

Figure 71. Five-Year Utility Bill Dynamics - $4 Minimum Bill – System Sized to 100 Percent of Average Consumption Load Case



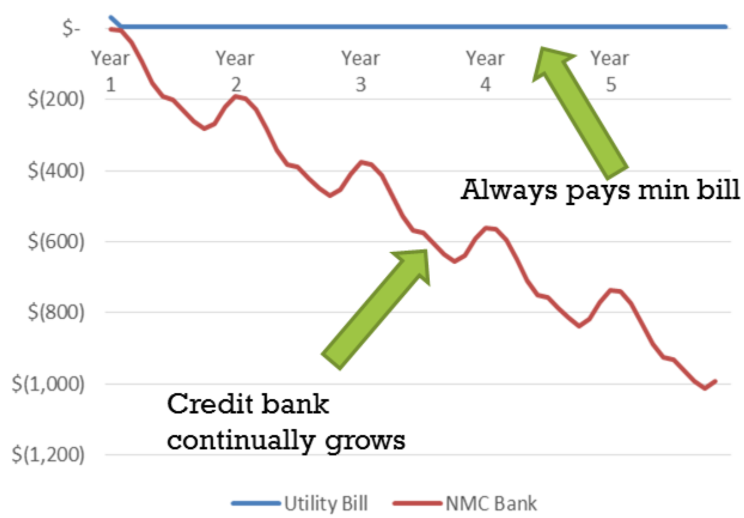
The second common bill dynamic is illustrated in Figure 728. Under this scenario, the PV system is sized smaller than the home's annual load. The customer's monthly bill rises and falls with seasonal changes in PV system production and onsite-load. Despite having a $4 minimum bill, under this case, the homeowner has no months in which a minimum bill is paid as that total utility bill always exceeds the minimum bill. Net metering credits are not banked under this scenario.

Figure 72. Five-Year Utility Bill Dynamics - $4 Minimum Bill – System Sized to 60 Percent of Average Consumption Load Case



The final common dynamic occurs when either the system is over-sized to the home load or when the minimum bill is high enough to cause the homeowner to always pay the minimum bill. Under this combination of factors, illustrated in Figure 9, the PV system continually generates net metering credits which are not monetized. As a result, the net metering credit bank grows over the life of the system. Notably, this is the same scenario customers with systems sized greater than their annual loads experience today even without a minimum bill. In the simplified modeling scenarios developed for this task, the net metering customer in this scenario does not take advantage of the opportunity to bilaterally sell excess net metering credits through the Schedule Z mechanism. A homeowner could gain a financial benefit from these unused credits by selling them to another utility customer, although the value at which these credits could be monetized in a bilateral net metering credit sale is unknown and would dictate the total financial loss, if any, resulting from this dynamic.

Figure 73. Utility Bill Dynamics - $4 Minimum Bill – System Sized to 120 Percent of Average Consumption Load Case



4.2.2 Effect of Minimum Bill on Total Utility Bill

To test the effect of different minimum bill levels on the overall utility bill paid by system owners, model runs were conducted for each of the system size cases and minimum bill levels. Both the average and low consumption home cases were modeled for each system size and minimum bill condition. First year, five-year and 20-year cumulative utility bills were calculated. These represent the total utility bills paid by customers including all customer charges, distribution charges and supply charges. The following tables show the results of this modeling. These results do not explicitly allocate utility bill costs between electricity suppliers and distribution utilities, however it is assumed that, during periods when a minimum bill is paid, those charges are paid exclusively to the distribution company without passing along funds to electric suppliers. A separate analysis is provided in the appendix of this report showing the total distribution portion of the customer bill for the average consumption case over the same time periods (see Figure 12).

Average Consumption Case / **Low Consumption Case**

Year 1 Utility Bill

PV/Load Ratio	$-	$4	$10	$25	$50	PV/Load Ratio	$-	$4	$10	$25	$50
1.2	$23	$67	$133	$300	$600	1.2	$13	$57	$123	$300	$600
1	$66	$88	$149	$314	$600	1	$57	$68	$131	$300	$600
0.8	$291	$291	$291	$333	$605	0.8	$169	$169	$169	$304	$600
0.6	$520	$520	$520	$520	$621	0.6	$284	$284	$284	$313	$600

Years 1-5 Total Utility Bill

PV/Load Ratio	$-	$4	$10	$25	$50	PV/Load Ratio	$-	$4	$10	$25	$50
1.2	$23	$268	$636	$1,558	$3,116	1.2	$13	$259	$626	$1,558	$3,116
1	$399	$403	$652	$1,571	$3,116	1	$324	$326	$634	$1,558	$3,116
0.8	$1,557	$1,557	$1,557	$1,591	$3,120	0.8	$903	$903	$903	$1,562	$3,116
0.6	$2,739	$2,739	$2,739	$2,739	$3,136	0.6	$1,494	$1,494	$1,494	$1,571	$3,116

Years 1-20 Total Utility Bill

PV/Load Ratio	$-	$4	$10	$25	$50	PV/Load Ratio	$-	$4	$10	$25	$50
1.2	$23	$1,172	$2,897	$7,210	$14,421	1.2	$13	$1,163	$2,887	$7,210	$14,421
1	$2,889	$2,889	$2,913	$7,224	$14,421	1	$2,021	$2,021	$2,895	$7,210	$14,421
0.8	$8,063	$8,063	$8,063	$8,063	$14,425	0.8	$4,608	$4,608	$4,608	$7,215	$14,421
0.6	$13,326	$13,326	$13,326	$13,326	$14,441	0.6	$7,240	$7,240	$7,240	$7,243	$14,421

These cases illustrate the potential dynamics of a minimum bill across a wide range of minimum bill thresholds. Under some conditions, total utility bills are unaffected by the addition of a minimum bill mechanism. In other cases, increasing minimum bill levels lead to significantly higher total utility bill collections. It is also notable that at higher minimum bill levels, customers pay the same cumulative utility bills regardless of the size of their PV systems. This effect is most pronounced in the $50 minimum bill categories where all customers, regardless of the size of their PV system or onsite load pay nearly the same utility bill.

Despite the increased costs for several of the cases with the implementation of a minimum bill compared to the no minimum bill case, customers in all cases see significant savings as a result of their solar installations regardless of the minimum bill. For reference, the modeled one-, five- and twenty-year total utility bills for the average-use customer without a solar PV system would be $1,214, $6,303 and $29,175 respectively. Each of these values is more than twice the modeled cumulative utility bill for the $50 minimum bill case.

This analysis only takes into account the total utility bill collections over the course of the analysis periods. As mentioned above, minimum bills can significantly change the timing of utility bill payments within an analysis period. For system size and load combinations where net metering credits are on an annual cycle in which credits are banked during periods of high production and fully utilized during months of low production, this would tend to decrease the monthly bill variance. The effect of this delay in monetizing system production is discussed in greater detail in the system financial analysis section of this report.

The same data is provided below in a different format that illustrates the relative increase in total utility bill for each system size and building consumption case relative to the no minimum bill case for that scenario.

	Average Consumption Case					
	PV/Load Ratio	$-	$4	$10	$25	$50
Year 1 Utility Bill	1.2	1.0	3.0	5.9	13.3	26.6
	1	1.0	1.3	2.3	4.8	9.1
	0.8	1.0	1.0	1.0	1.1	2.1
	0.6	1.0	1.0	1.0	1.0	1.2
	PV/Load Ratio	$-	$4	$10	$25	$50
Years 1-5 Utility Bill	1.2	1.0	11.9	28.2	69.1	138.1
	1	1.0	1.0	1.6	3.9	7.8
	0.8	1.0	1.0	1.0	1.0	2.0
	0.6	1.0	1.0	1.0	1.0	1.1
	PV/Load Ratio	$-	$4	$10	$25	$50
Years 1-20 Utility Bill	1.2	1.0	52.0	128.4	319.6	639.3
	1	1.0	1.0	1.0	2.5	5.0
	0.8	1.0	1.0	1.0	1.0	1.8
	0.6	1.0	1.0	1.0	1.0	1.1

	Low Consumption Case					
	PV/Load Ratio	$-	$4	$10	$25	$50
Year 1 Utility Bill	1.2	1.0	4.3	9.3	22.6	45.2
	1	1.0	1.2	2.3	5.3	10.6
	0.8	1.0	1.0	1.0	1.8	3.5
	0.6	1.0	1.0	1.0	1.1	2.1
	PV/Load Ratio	$-	$4	$10	$25	$50
Years 1-5 Utility Bill	1.2	1.0	19.5	47.2	117.3	155.8
	1	1.0	1.0	2.0	4.8	9.2
	0.8	1.0	1.0	1.0	1.7	3.4
	0.6	1.0	1.0	1.0	1.1	2.1
	PV/Load Ratio	$-	$4	$10	$25	$50
Years 1-20 Utility Bill	1.2	1.0	87.6	217.4	543.0	721.1
	1	1.0	1.0	1.4	3.6	6.9
	0.8	1.0	1.0	1.0	1.6	3.1
	0.6	1.0	1.0	1.0	1.0	2.0

As the data shows, the total change in utility bill over the time periods analyzed is highly dependent on the system size relative to total site load (PV/Load Ratio). For many of the scenarios, a minimum bill leads to no increase in total utility bills, while in others, the increase is potentially substantial on a percentage basis. Systems sized to produce the total annual onsite load and those sized to produce more than the total onsite load see an increased utility bill at all minimum bill levels in the 1 and 1-5 year timeframes. Alternatively, systems undersized to total load do not see any increase in total utility bill under the $4 and $10 minimum bill cases for all analysis timeframes.

The above table also illustrates the disproportionate effect of a fixed minimum bill on customers with lower consumption. For cases where a minimum bill leads to an increase in total utility bill, the relative increase is typically higher in the low consumption case compared to the high consumption case.[102] This effect could potentially be mitigated with a minimum bill structure that scales to the total on-site consumption. Under such a structure, homes with lower inherent consumption would be subject to lower minimum bill rates.

An important simplification in this analysis is that system owners that generate excess net metering credits for over-sized systems do not monetize those credits through bilateral net metering credit sales to other residents through the Schedule Z mechanism. System owners under this scenario could seek to monetize unused credits through this transfer mechanism. Therefore any increased utility revenue due to a minimum bill from an individual system owner may not lead to an overall utility-wide increase in bill collections as any unused net metering credits could be monetized by other utility customers, lowering their utility bills. Instead of increasing the net bill collections from net metering customers, a minimum bill may lead to an overall increase in the number of customers taking advantage of net metering (through the Schedule Z mechanism) with the total benefit available to any individual net metering customer being decreased.

4.2.3 Effect of Minimum Bill on System Rates of Return and Simple Payback

Minimum bills can potentially affect PV system economics in several ways. For instance, a minimum bill can delay a system owner's ability to monetize the production of their PV system by several months, potentially lowering total

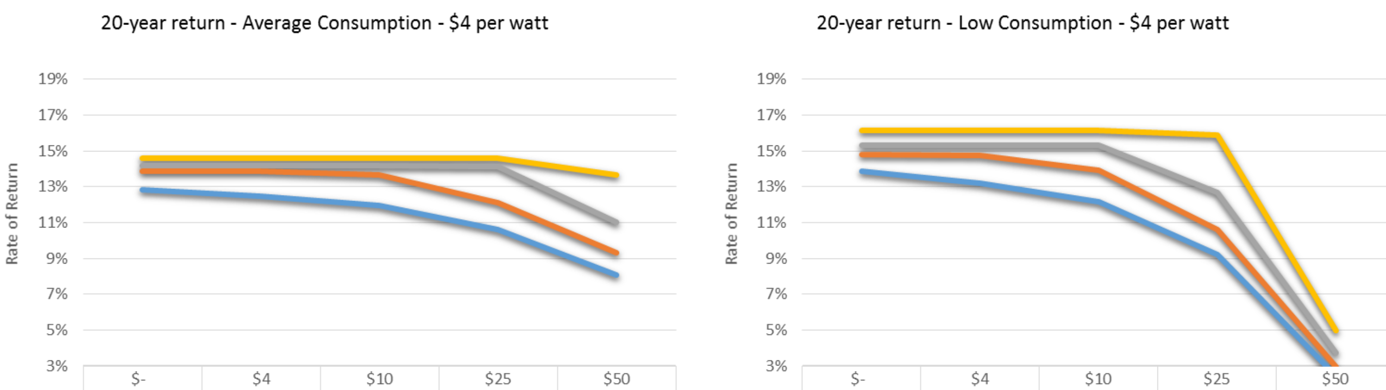
[102] The effect is not seen in the Year 1 case due to the effects of the utility bill in the first analysis month. The timing of the start of the analysis, in January, creates a high first-month utility bill that influences this analysis.

system investment returns and increasing simple paybacks. Additionally, as noted previously, a minimum bill can also prevent a system owner from monetizing the entirety of their system's electricity production if the combination of system size and minimum bill threshold create a dynamic in which credits are continually banked.[103]

In order to determine the potential financial impacts of a minimum bill on system economics, 20-year internal rate of return[104] and simple payback (in years) were calculated for each of the modeling cases assuming $3, $4 and $5 dollar per watt installation costs. Both these financial metrics were included in the analysis as some residents may make decisions based on simple payback calculations while others may instead evaluate the systems lifetime rate of return. As mentioned above, this analysis included revenue streams from sources beyond utility bill savings including the 30% federal tax credit, the Massachusetts residential tax credit and SREC revenues. These components make up a significant portion of a system's total financial value.

Figure 10 below show the 20-year rates of return for a system systems built for $4 per watt scaled to supply various onsite loads. As the figures illustrate, the range of potential system rates of returns is larger for the Low Consumption scenario, ranging from 16.1% in the no minimum bill case serving 60% of the annual home load to a 2.4% rate of return for the $50 minimum bill case where the system is sized to supply 120% of household annual load. The Average Consumption case range from 14.6% to 8.1% indicating that the minimum bills have a smaller overall impact on system economics compared to the smaller household load scenarios.

Figure 74. Internal Rates of Return for Two Residential Modeling Cases



	$-	$4	$10	$25	$50
1.2	12.8%	12.5%	12.0%	10.6%	8.1%
1	13.9%	13.9%	13.7%	12.1%	9.3%
0.8	14.2%	14.2%	14.2%	14.1%	11.0%
0.6	14.6%	14.6%	14.6%	14.6%	13.7%

	$-	$4	$10	$25	$50
1.2	13.9%	13.2%	12.1%	9.2%	2.4%
1	14.8%	14.7%	13.9%	10.6%	3.0%
0.8	15.3%	15.3%	15.3%	12.7%	3.7%
0.6	16.1%	16.1%	16.1%	15.9%	5.0%

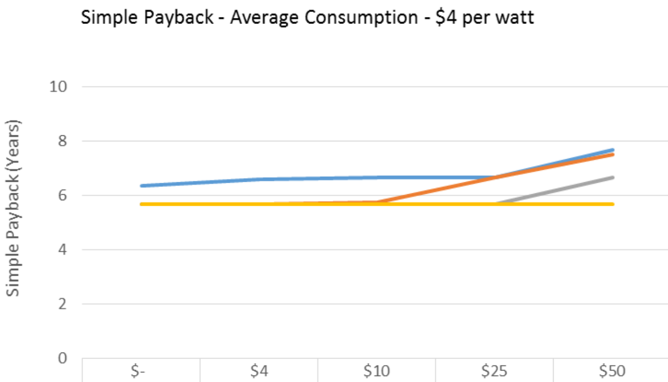
Figures 11 shows the simple payback for the same cases discussed above. As with the rate of return metric, the simple payback results show a wider potential range of paybacks for systems in the Low Consumption cases, ranging between 5.0 years and 9.7 years indicated a greater sensitivity to minimum bill effects for the lower consumption customer case.[105]

[103] As previously mentioned, this loss could be mitigated by selling unused credits to other utility customers.

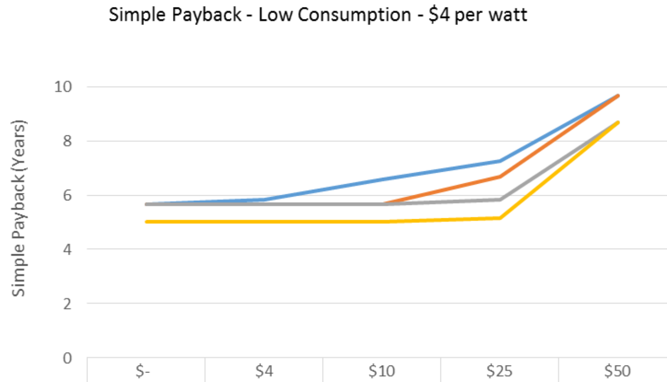
[104] The internal rate of return for the system is the equivalent to the discount rate at which the net present value of the total investment would be zero.

[105] The simple payback results show less overall variability in part because it is a less sensitive metric and because of the unevenness of system cash flow over the life of the system. For instance, SRECs are assumed to be monetized once a year after the SREC clearinghouse auction meaning that many of the modeled systems have the same simple payback values despite having differing overall cash flow profiles and internal rates of return.

Figure 75. Simple Payback for Two Residential Modeling Cases



	$-	$4	$10	$25	$50
1.2	6.3	6.6	6.7	6.7	7.7
1	5.7	5.7	5.8	6.7	7.5
0.8	5.7	5.7	5.7	5.7	6.7
0.6	5.7	5.7	5.7	5.7	5.7



	$-	$4	$10	$25	$50
1.2	5.7	5.8	6.6	7.3	9.7
1	5.7	5.7	5.7	6.7	9.7
0.8	5.7	5.7	5.7	5.8	8.7
0.6	5.0	5.0	5.0	5.2	8.7

Additional scenarios for $3 and $5 dollar per watt installed costs are provided as an appendix to this report. In general the dynamics highlighted above are observed in these alternative cost cases.

As this analysis shows, the effects of minimum bills on project financial returns is highly dependent on the level of the minimum bill, the overall home load, the system cost, and the relative size of the system to the home load. Even within this simplified case, the range of effects from these parameters is substantial. As previously mentioned in this section, modeling results that assume different parameters would significantly change modeling outputs. Given the significant variation in potential system configurations, utility rates, financing and ownership structures, and system costs, it is difficult to generalize what the potential effects an undefined minimum bill policy could have on the development of the Massachusetts solar market. Additionally, any lost system value stream that results from the implementation of a minimum bill could potentially offset through adjustments from other incentive programs. If a minimum bill were to significantly decrease system economics, increased SREC market prices could potentially compensate for these losses.

4.2.4 Potential Impacts of a Minimum Bill on Virtual Net Metered Customers

The modeling presented in this section represents a PV system sited on a homeowner's roof. Massachusetts has one of the most expansive virtual net metering regulations in the nation, allowing net metering credits from PV systems anywhere within a customer's utility territory and ISO load zone to be used to reduce their utility bill. This has facilitated a number of community solar ownership models and has also supported the development of large ground-mounted systems that produce credits that serve multiple utility accounts of the same customer. The dynamics of a minimum bill related to these installation types were not modeled under this task, however the imposition of a minimum bill on customers using virtual net metering could substantially mirror the effects seen in the residential minimum bill model.

Whether a system is net metered or virtually net metered would only make a limited impact on project economics under a minimum bill. For instance, customers that over-size their net metering contracts relative to both their annual consumption and the minimum bill threshold would be unable to fully benefit from their net metering credit purchases. For community solar installations serving low-use customers, the effects would likely be similar to those seen in the low-consumption case modeled above. From the perspective of PV system economics, having multiple net metering credit offtakers subject to a minimum bill could lead to a lower overall project size relative to the size of a system that could be developed without a minimum bill. For a large community solar installation, this effect could be overcome by increasing the number of participants taking advantage of the system, with each participant taking less of the systems overall production in order to avoid continually paying the minimum bill. Additionally, the effect of a minimum bill on the PV system exporting account, depending on the size of the minimum bill and the overall project size, could impact project economics.

The dynamics of utility revenue recovery, however, may have important differences depending on whether a PV system serves an onsite load or is used primarily for virtual net metering. Under virtual net metered system models, where systems serve minimal onsite load, utilities are able to recover the full value of the exported net metering credits (transmission, distribution and basic service supply costs, etc.). PV systems that predominantly serve on-site loads lead to lower overall increases in utility revenue recovery charges as the utilities may only recover lost revenue associated with lost base distribution revenues and not basic service supply costs for electricity that is used on-site. Minimum bill designs that account for these differences have not been implemented in other jurisdictions, however a minimum bill could be designed to address differences in associated utility system costs between virtual net-metered and on-site net-metered systems.

For large PV systems serving a single customer with multiple meters, minimum bill impacts on system economics would depend on the number of utility meters served, the system size, the minimum bill level and the overall consumption the customer can offset via net metering. If the customer has sufficient annual consumption to fully utilize all the system output and can assign net metering credits in a manner that avoids the minimum bill on each account, project economics may be only modestly affected by the minimum bill. Alternatively, if a customer with multiple meters does not have sufficient load to monetize the entirety of their system's production without continually paying minimum bill levels, the economics of the project may be affected.

5 Conclusions

Minimum bill policies have been implemented in a limited number of jurisdictions across the country. These mechanisms have been used to ensure a minimum revenue is collected from all ratepayers within a rate class while also maintaining volumetric charges that promote energy conservation goals. Minimum bill policies have been implemented in some of the most active and growing solar markets in the United States, suggesting that these rates have not been incompatible with solar market growth. Critically, the existing policies examined under this task have established minimum charges at or below $25 a month. The potential effects of higher minimum bills, such as those recently proposed in Hawaii, on solar market develop is unknown at this time.

Modeling of a hypothetical residential Massachusetts PV system shows that the potential effects of a minimum bill in the Commonwealth on both customer utility charges and PV system economics would be highly dependent on the specifics of how the minimum bill policy was defined and the specific parameters of the PV system. Under certain modeling conditions a minimum bill policy resulted in limited changes in total utility bill costs for the modeled system while under other conditions, a minimum bill was shown to significantly increase utility bill costs for PV system owners. Without a better defined minimum bill proposal, drawing conclusions about how a minimum bill could affect either utility cost recovery or PV market dynamics is not possible. Despite this, modeling results suggested that a minimum bill that was set at a fixed level for all customers within a rate class would be more likely to affect customers with lower consumption compared to those with higher annual consumption levels. Another key finding is that the size of a PV system relative to the annual load of a home significantly influences the overall impact of a minimum bill on system economics, with systems sized to meet more than the customer's annual load seeing the greatest impacts from a minimum bill. Finally, potential effects of a minimum bill on PV systems with more complex ownership structures or on commercial PV system were not modeled under this task. A minimum bill policy could potentially affect these market segments in ways not explored through the modeling completed in this section. However, as with simplified model presented under this task, any impacts on utility bills, PV system economics and overall market dynamics would likely be highly dependent on the specifics of the minimum bill policy and the individual system parameters.

Figure 12. 20-Year IRR and Simple Payback Matrix for Average Consumption Case

20-Year IRR

	PV/Load Ratio	$0	$4	$10	$25	$50
$3 per Watt	1.2	18.7%	18.3%	17.7%	16.2%	13.3%
	1	20.1%	20.0%	19.7%	18.0%	14.8%
	0.8	20.5%	20.5%	20.5%	20.4%	16.8%
	0.6	21.1%	21.1%	21.1%	21.1%	20.0%
$4 per Watt	1.2	12.8%	12.5%	12.0%	10.6%	8.1%
	1	13.9%	13.9%	13.7%	12.1%	9.3%
	0.8	14.2%	14.2%	14.2%	14.1%	11.0%
	0.6	14.6%	14.6%	14.6%	14.6%	13.7%
$5 per Watt	1.2	9.0%	8.7%	8.2%	6.9%	4.6%
	1	9.9%	9.9%	9.7%	8.3%	5.7%
	0.8	10.1%	10.1%	10.1%	10.0%	7.3%
	0.6	10.4%	10.4%	10.4%	10.4%	9.6%

Simple Payback (Years)

	PV/Load Ratio	$0	$4	$10	$25	$50
$3 per Watt	1.2	4.7	4.7	4.7	5.3	5.7
	1	4.7	4.7	4.7	4.7	5.7
	0.8	4.7	4.7	4.7	4.7	4.7
	0.6	4.3	4.3	4.3	4.3	4.7
$4 per Watt	1.2	6.3	6.6	6.7	6.7	7.7
	1	5.7	5.7	5.8	6.7	7.5
	0.8	5.7	5.7	5.7	5.7	6.7
	0.6	5.7	5.7	5.7	5.7	5.7
$5 per Watt	1.2	7.7	7.7	8.0	8.7	9.7
	1	7.6	7.6	7.7	7.8	9.3
	0.8	7.4	7.4	7.4	7.4	8.7
	0.6	7.1	7.1	7.1	7.1	7.7

Figure 13. 20-Year IRR and Simple Payback Matrix for Low Consumption Case

20-Year IRR

	PV/Load Ratio	$0	$4	$10	$25	$50
$3 per Watt	1.2	20.2%	19.4%	18.2%	14.9%	7.8%
	1	21.4%	21.4%	20.4%	16.6%	8.5%
	0.8	22.2%	22.2%	22.2%	19.1%	9.4%
	0.6	22.6%	22.6%	22.6%	22.2%	10.2%
$4 per Watt	1.2	13.9%	13.2%	12.1%	9.2%	2.4%
	1	14.8%	14.7%	13.9%	10.6%	3.0%
	0.8	15.3%	15.3%	15.3%	12.7%	3.7%
	0.6	16.1%	16.1%	16.1%	15.9%	5.0%
$5 per Watt	1.2	9.8%	9.2%	8.2%	5.5%	-1.2%
	1	10.5%	10.5%	9.8%	6.8%	-0.7%
	0.8	10.9%	10.9%	10.9%	8.6%	-0.1%
	0.6	11.5%	11.5%	11.5%	11.3%	1.0%

Simple Payback (Years)

	PV/Load Ratio	$0	$4	$10	$25	$50
$3 per Watt	1.2	4.7	4.7	4.7	5.7	6.7
	1	4.2	4.2	4.6	4.7	6.7
	0.8	3.7	3.7	3.7	4.7	6.7
	0.6	3.7	3.7	3.7	3.7	5.7
$4 per Watt	1.2	5.7	5.8	6.6	7.3	9.7
	1	5.7	5.7	5.7	6.7	9.7
	0.8	5.7	5.7	5.7	5.8	8.7
	0.6	5.0	5.0	5.0	5.2	8.7
$5 per Watt	1.2	7.6	7.7	7.7	9.2	-
	1	6.8	6.9	7.6	8.7	-
	0.8	6.7	6.7	6.7	7.7	-
	0.6	6.7	6.7	6.7	6.7	10.7

Figure 14. Distribution Portion of Utility Bill for Average Consumption Case

Year 1 Utility Bill

PV/Load Ratio	$-	$4	$10	$25	$50
1.2	$12	$56	$122	$300	$600
1	$56	$65	$129	$300	$600
0.8	$156	$156	$156	$301	$600
0.6	$262	$262	$262	$307	$600

Years 1-5 Total Utility Bill

PV/Load Ratio	$-	$4	$10	$25	$50
1.2	$12	$257	$625	$1,558	$3,116
1	$314	$316	$632	$1,558	$3,116
0.8	$834	$834	$834	$1,558	$3,116
0.6	$1,377	$1,377	$1,377	$1,565	$3,116

Years 1-20 Total Utility Bill

PV/Load Ratio	$-	$4	$10	$25	$50
1.2	$12	$1,162	$2,886	$7,210	$14,421
1	$1,915	$1,915	$2,893	$7,210	$14,421
0.8	$4,249	$4,249	$4,249	$7,211	$14,421
0.6	$6,673	$6,673	$6,673	$7,218	$14,421

Appendix II Current Massachusetts Utility Rates

Massachusetts utility rates, including all customer charges, demand charges, program charges and basic service supply charges are published by each utility company as rates are updated. Given the complexity of the many rate structures offered by the state's four investor-owned utilities, those rate sheets are provided in the following links for reference:

National Grid:

- Nantucket Electric: https://www.nationalgridus.com/non_html/1114nant.pdf
- National Grid: https://www.nationalgridus.com/non_html/1114meco.pdf

Eversource East (former NSTAR territories)

- Boston Edison: https://www.eversource.com/Content/docs/default-source/rates-tariffs/190.pdf?sfvrsn=4
- Cambridge Electric: https://www.eversource.com/Content/docs/default-source/rates-tariffs/290.pdf?sfvrsn=4
- Commonwealth Electric: https://www.eversource.com/Content/docs/default-source/rates-tariffs/390.pdf?sfvrsn=4

Eversource West (formerly WMECO): https://www.eversource.com/Content/docs/default-source/rates-tariffs/1052.pdf?sfvrsn=6

Unitil: http://unitil.com/sites/default/files/tariffs/E_dpu274_Summary_of_Rates_010115.pdf

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APPENDIX A: Task 0 Interview Summaries and Written Responses

Net Metering Task Force, Group A- Utilities

1.20.15

9:00-10:30 a.m.

• Amy Rabinowitz, National Grid	• Kerry Britland, Eversource
• Brian Rice, Eversource	• Laura Bickel, National Grid
• Hayley Dunn, Eversource	• Camilo Serna, Eversource
• Richard Chin, Eversource	• Andy Belden, Meister Consultants Group
• Peter Zschokke, National Grid	• Bob Grace, Sustainable Energy Advantage
• Ian Springsteel, National Grid	• Kathryn Wright, Meister Consultants Group
• Timothy Roughan, National Grid	

As per a request from focus group participants, notes are attributed to speakers from each utility.

Participants introduced themselves, and were informed the session would not be recorded. Participants were given the opportunity to provide additional written comments to supplement the call.

1. Stakeholder objectives and priorities from the Task Force process

What are your goals and objectives for the task force? Of those, what is your most important objective and why? To the extent that goals or objectives may conflict, how would you prioritize?

National Grid: We will be providing written comments by Friday, which will summarize our comments. Supportive of clean energy goals state has and helping meet 1600MW goal and anything that comes beyond that, but we must not lose sight of how we hit the goals and cost-effectiveness, particularly for NEM and SRECs. How can we redefine them to be more cost effective to ensure rate fairness, transparency and make sure customers are not paying anything above market prices?

Eversource: We will also submit written comments. The state needs sustainable renewable programs which can be enjoyed by all customers, not a few. Ideal programs would be fair, cost-effective and competitive.

2. Long term Massachusetts solar market goals

The current stated goal of the Massachusetts solar policies is to reach 1,600 MW of installed solar capacity in the 2020 timeframe. Please discuss your perspective on this MW goal, its timing, and the appropriate objectives for the state solar market beyond the timing and quantity of this goal.

National Grid: We think 1600MW is an aggressive, but achievable goal. It represents ~4% of energy supply and ~12% of peak demand. A lot of this will be based on our company's ability to interconnect, overall development funding and the market. With the high incentive level we are going to achieve this goal early. Cited virtual net metering in particular because developers can choose the site location and then not contribute to system costs. The costs of the NEM and SREC programs need to be reduced to increase net benefits. We also need to reduce payments to solar developers and investors, particularly those from out of state.

Eversource: Believes that Mass. is paying well above market prices. SRECs and NEM are nearly seven times more than wholesale power and four times more than wholesale renewable programs. Mass.'s program costs three times Conn.'s program, which participant's company also participates in. NEM customers are receiving $.50/kWh. There are better ways to structure the program- we need to develop an all-in cost per kWh of installed solar and accompanying cost-effectiveness goals. We've seen solar prices drop with increases in volume and manufacturing efficiencies and the level of incentives should be decreasing as well. Over the next few years, $7 billion will be paid above market costs to support solar development.

Eversource: We looked at results under the ZREC program for 15-year contracts. CT has lower prices and lower NEM support. We also looked at other states. We compared this on a straight rate perspective. This is not apples to apples comparison, but if you were to do so, we find that the net cost of the ZREC program is less than MA no matter what perspective you take.

National Grid: Agreed with Participant 10, and adds costs are high when compared with Rhode Island too.

Eversource: We are looking at NEM around $0.15 credit plus basic service. The 2015 vintage for SREC-I is above 400 dollars. This gets us at or above $0.50/kWh, though in other years the amount has been lower.

3. Perspectives on current net metering approach

Solar PV systems in Massachusetts typically benefit from net metering with various system sizes and configurations receiving different net metering benefits. Additionally, volumetric caps to net metering have been revised through legislation on multiple occasions over the past several years. Please provide your perspective on the current Massachusetts net metering approach.

National Grid: Current system is not well designed. There are two issues: cost shifts between customer classes and distributed generators (DG) only paying for a portion of their fixed costs. DG customers are receiving reliability services and the ability to transact and monetize solar energy. Other non-transmission and distribution costs are not being recovered or shifted to others, such as the renewable and efficiency funds as well as other programs. Once you add-in the VNEM concept these issues are made worse because it is a significant administrative burden for utilities. We have to transfer payments from generator to customer accounts, which is not related to how power is being produced or used. There may also be an issue with community solar providers and ISO New England rules. There was a challenge regarding settlement at the DPU in 2011, with the result being that some suppliers are dropping customers since they can't serve them.

National Grid: ISO defines a large unit SOGs as greater than 5MW. It's not clear how they should be treated who should take ownership of these units. For customer's that are interval-metered, suppliers are being billed based on generation. The net metering credit is a construct which creates a mismatch between the suppliers and what ISO needs to register in the system. Anyone bidding into basic service will bid at a higher rate to take into account this issue. We are receiving 1,000s of applications for PV interconnections, and will likely cause higher basic service charges in the future to account for this risk. In the smart grid pilot, 2,200 of 15,000 have left basic service because of costs. Now is the time to consider this issue. Community solar providers should be administered by ISO New England and regulated by FERC as retail providers.

National Grid: The NEM construct may be appropriate for giving solar a jump-start, but it is not sustainable for a long-term program. If you have every customer net metering to zero out their bills, no one is paying for the costs of the system. All PV systems are receiving same net metering credit value. Using 2015 rates, it can be shown that VNEM costs customers more than NEM coincident with customer load. VNEM results in a 40% higher cost than most behind the meter systems. VNEM uses distribution system and provides less benefit.

4. Perspectives on current Massachusetts solar incentive model approach

Massachusetts solar installations typically benefit from a range of incentives, including SRECs, federal tax credits and net metering being major contributors to system economics. Please discuss your perspective on the current mix of incentives other than net metering (and virtual net metering) available to Massachusetts solar systems with a particular focus on the Massachusetts SREC incentive.

National Grid: SREC obligations put a higher cost on IOU customers than it should. Prices are not declining with time even though PV is cheaper. SREC-II narrowed the floor and ceiling with declining price, but SREC values are still too high and volatile. This creates artificial risk and financing difficulties. If we introduced competition based on cost and total development, it would help developers. A fixed rate would give customers a hedge value and should lower costs. The SREC program is high cost/high risk and induces boom-bust cycles. This makes it hard for solar development costs to come down effectively. A competitively procured amount of solar PV production would be better.

Eversource: SREC incentives exceed what’s necessary to deploy solar in the state. CT, NJ and RI all have lower subsidies. We understand the need to provide price certainty, but believe transparency and competitiveness is key element. Having administratively set rates disrupts competition. We can still give appropriate incentives. Some amount of incentives should be set-aside and we should think about how much solar we can procure with a fixed budget. This is much like the CT approach.

Eversource: In NJ, long-term contract support and banking have been able to augment the SREC program and stabilize market participants and the market, even without fixed floor. We think solar could be procured through RPS program without price support. Some market participants are sophisticated and should be able to manage this risk. We have seen this in NJ after the SREC program was changed. In the case of efficiency, incentives and rebates were introduced to jump start the market, but the goal was to reduce the incentives once the market is working. We need to think about how EE works and bring that to the next evolution of the SREC program.

5. **Perspectives on other solar incentive models**

Other states have implemented a range of incentive program types in order to grow their solar markets. Several program types that you may be aware of include (but are not limited to):

- *Standard offer incentive programs (aka. feed-in tariffs)*
- *Declining block incentive programs*
- *Competitive procurements (aka. auctions or solicitations)*

There are also many variations on these approaches, as well as co-policies. Are any of these incentive program types of particular interest to you? Please discuss your impressions of these or other incentive program types that you may be aware of, and whether we should focus on particular incentive types that are of interest to you. How do you think the effectiveness of these incentive program types vary for different solar installation types (e.g. residential vs. utility scale)? What options would you like to see the consulting team consider and analyze for Massachusetts?

Eversource: It is more about what parameters are needed instead of focusing on a single program having looked at other states. A program should be fair, transparent, and appropriate to level of solar development in industry. DG should be incentivized based on known, measurable benefits and reevaluated and modified as policy goals are met. Externalities such as jobs and the environment should be treated consistently between the utility scale and DG. Any price above wholesale price should be regulated by DPU. We are supportive of the long-term contracting programs in CT. We also look to RPS programs to have transparent prices through bidding and no discrimination between project types. A tariff system would be easier administratively. We understand the difficulty of following bid schedule, and would be OK with a declining block incentive if the rates were set transparently and the schedule ends at 0. If RPS programs are retained, it should not have a floor, but instead should have these parameters.

National Grid: In RI, renewable energy growth program is launched soon and will be ½ the cost of the MA program. All of the payments are under an approved tariff. Small and medium systems have a fixed –price performance based tariff. Non-residential systems receive a fixed payment for 20-years. Residential systems receive NEM credits and further incentives for performance. A public process sets rate annually based on the market and competitive procurements. Large solar systems must bid into a competitive procurement with a ceiling. During the last auction sizes ranged from 172kW to 1.25 MW. All-in $150-240/MWh bids. Most averaged $200/MWh. New York has used competitive solicitation for 200 kW and up. That program has provided awards worth the equivalent of SREC price of $50 for 10 years at a 10% discount rate. However, it doesn't provide hedge-value. NY is moving to declining block program with a step schedule. This is less cost-effective compared to competitive model and insensitive to market changes and needed rates of return. Our view is that mix of standard PBI tariff rates for smaller systems and competitively set tariff rates for larger systems would be best.

6. **Perspectives on future use of net metering, as well as minimum bill provisions**

During the past year, efforts have been made to revise the framework for net metering in Massachusetts including the addition of a minimum bill for all electricity ratepayers. Please discuss *your perspective on the future use of net metering/virtual in Massachusetts and, to the extent you are able, what options or changes would you like to see and why?*

National Grid: Thinks a minimum bill would reduce inequities between ratepayers and would help NEM participants pay for their fixed costs and not impact the energy efficiency incentive that volumetric rates provide. This would not fully resolve all of the issues with cost-recovery and cross-subsidization, but it can transition us to a world where people pay for what they are using from the utility system.

Eversource: We have indicated problems we see with the current structure. Rate design should function based on cost allocation, efficiency, continuity, and fairness. We feel that net metering violates most of these. Without proper cost-allocation, we can't meet state goals. We need new rate designs which disaggregate the benefits and costs of solar. We want to be able to get the data points we need to create a new rate design. This includes the power exported to our company, the power delivered to customers and the production of DG facilities. We need to recover fixed T&D costs at a level similar to non-DG customers. A separate generation transaction would be compensated – there are many different options. Another alternative is to develop valuation of solar methodology to compensate for energy being distributed. Then the incentives would come into play- we've discussed how they should be structured, and that they should decline over time. We also propose a new customer class with higher T&D customer charges, but it wouldn't be subject to net metering. The bottom line is that we need to address this in a comprehensive manner with a formal regulatory proceeding which can determine appropriate rate design and benefits of DG. Regulatory bodies were established to do this.

Eversource: We believe that the minimum bill is one method of rate design. NEM should reflect the DPUs principles, costs should be properly allocated to customers, and it should have customer protection designed into it. Separation between delivery and export of power will enable a better rate design. VNEM needs to be re-evaluated entirely.

National Grid: Seconds that DPU is the right forum to balance all needs for rate design. As with every other rate change, a minimum bill would have to be customer class specific.

Consultant: Do you have any feedback on if existing installations should be grandfathered for some period of time for rate changes?

Eversource: It depends on what the rate design is and if it will accommodate existing facilities. Any design would have to take that into account. Difficult to explain without a specific example, but it should be a part of discussions.

National Grid: Seconds Eversource's thoughts. Open to a transition, but hard to say more without specifics.

7. Perspectives on policy transitions

A. *At the 2nd Task Force meeting, it was suggested that analysis should account for* ***uncertainty costs****, (i.e., transition costs due to changing goals and programs.) Please discuss qualitatively the nature* *of these costs as you see them, and whether and how you might suggest such costs could or should be quantified.*

B. *Are there particular threshold milestones where it might make sense to consider policy transitions in order to minimize such costs? What other means are available to minimize such costs?*

Eversource: It is difficult to know what kinds of costs there might be. The marketplace is full of uncertainty. Some of the players are becoming sophisticated and should be able to deal with change. Programs are not expected to be exactly the same forever. Any program change should incorporate transition into design. The cost of running the existing program would likely be more than the transition cost.

National Grid: Unclear of what the definition of uncertainty cost is in the question. Costs are being incurred today for the program and the distribution grid. Program participants in the future may be uncertain about what their benefits will be from the utility and for their generation. Certainly, clarity from the DPU would help about where we are going in the future as well as a timeline so everyone is familiar with rate design and other changes. We want for customers to pay for the services provided by grid and be compensated for the services they provide. We need a framework, clarity, time and customer fairness. If VNEM is taken to the extreme no one is paying for the grid. This can't happen. Costs for one party are savings for another. Who is the right party to pay for the distribution grid?

National Grid: The tighter the timeline, the less risk for all the parties involved. Long timelines leave more room for revisions.

8. Utility- specific questions

How would you propose a minimum bill calculation methodology be applied? What other models would you point to that are viable for achieving your objectives?

National Grid: Minimum bill design to be addressed in the written comments.

Eversource: We will provide written responses to questions and a separate attachment on the minimum bill. A minimum bill is less preferable than an appropriate rate design.

With respect to FCM revenues for current Class II and III systems, for which utilities secure certain rights under net metering tariffs, please describe your current practices, and future plans.

Eversource: Haven't offered any NEM system into FCM. We don't control those assets so we aren't willing to assume risk of obligation of those systems. FCM value is still realized through a load reduction, perhaps not of quickly, but it is still there. We will continue to evaluate- if the risks could be addressed maybe it is an option.

National Grid: To date, we have not taken advantage of this, but it is under consideration.

Are utility system integration costs for solar projects now fully borne by project owners?

National Grid: Significant O&M costs, taxes, tree trimming, not being paid by customers even if they are paying upgrade costs. This can be up to 6% of the costs, annually. This is a cost not being borne by DG customers. 1,000 customers applying for interconnection- the $50-70 per meter costs are not being recovered since the simplified process has no fees. There are also costs from issues arising around Schedule Z for utility staff. A minimum 2-3 FTEs work on this issue and that number will grow.

Eversource: We will be providing data on O&M appropriate numbers.

What are the expected potential impacts of Grid Modernization/Time-Varying Rates efforts on net metering value and framework?

Eversource: We are in the very early stages of thinking about implementation. Hard to assess the impacts without specifics.

National Grid: We need to think holistically about costs incurred and recovery. What types of issues might arise from over or under recovering? What happens if customers over produce during a peak?

National Grid: Our decision around TOU rates carries risks for the wholesale market. There is a disconnect between retail-TOU pilots and the way costs are incurred at the wholesale level.

National Grid: We need to reflect on DG Forecast Working Group findings at ISO New England and the FCM for solar.

What are your experiences in other state solar markets with alternative incentive models or policies in place?

No further comments.

Please describe your past and expected future participation in SREC floor price auctions.

National Grid: We haven't participated. We are in the market for SRECs prior to the auction and have typically gotten enough for load. To participate in the auction would be speculative since it would occur before the load was known.

Eversource: Our experience is similar. Our only demand for SRECs is to serve basic service load. We have a process for serving basic service load, and we don't look at time horizons very far in the future. May be the case will be different in the future.

What information can you make available to the consulting team to help us assess the role of avoided T&D cost (if/where applicable) and avoided distribution losses resulting from installation of distributed solar generation?

Information will be provided.

9. Other topics

Are there any major topics or perspectives related to the Task Force's scope that we have not discussed today that you would like to comment on?

Eversource: Recognizes there is a challenge to address everything through legislative process and report. We need regulatory proceedings, and to reflect value that grid provides to the DG. The value of these systems can increase with increased utility involvement in deployment. We believe we provide more services to DG, such as reliability and compensation for variable outputs, frequency regulation and redundancy services, voltage, and start-up power. This needs to be key element of rate design and as initial element of the analysis.

National Grid: Recommended EPRI's paper on the Integrated Grid, and agreed with Eversource regarding the need to reflect the value of grid services. How will the consultant team get costs data from developers and host customers?

Net Metering Task Force Focus Group Interviews
Group B- Utility Customers and Customer Advocates
1.21.2015
3:00 p.m-4:30 p.m

• David Colton, Town Administrator, Easton	• Andy Belden, Meister Consultants Group
• Bob Rio, AIM Representative	• Bob Grace, Sustainable Energy Advantage
	• Kathryn Wright, Meister Consultants Group

1. Stakeholder objectives and priorities from the Task Force process

What are your goals and objectives for the task force? Of those, what is your most important objective and why? To the extent that goals or objectives may conflict, how would you prioritize?

Participant 2- Would like to make sure the result continues to allow development of solar energy in the NEM/VNEM paradigm so that we can continue to reduce our costs of energy. Acknowledge that the subsidies need to be paid by someone. Regardless of what happens, public sector projects need to remain viable. As a secondary goal- alternative energy is important and we need to continue to diversify energy mix for well-being of planet. Third- Don't think we want to see change in the way that electricity is produced, generated and distributed. The separation of distribution and generation companies has been good for MA. We do not want distribution companies to gain more control over generation assets, even if they are distributed. Utilities have demonstrated that they are overstretched with their existing priorities.

Participant 1- The goal is to find the best way to have a solar program. That may or may not be NEM. We need to review rate and incentives structures to ensure they are proper and not overly generous. We need to stay on the trajectory of increased solar. Acknowledges who is paying for subsidies is a huge issue as well as freeridership. In general, people don't understand that the incentives are misaligned with the market. Our goal should be to look at the market and what it takes to develop solar and align incentives for people to install high-value installations. It is not clear what the implications for Massachusetts are or electric stability growth isn't managed.

2. Long term Massachusetts solar market goals

The current stated goal of the Massachusetts solar policies is to reach 1,600 MW of installed solar capacity in the 2020 timeframe. Please discuss your perspective on this MW goal, its timing, and the appropriate objectives for the state solar market beyond the timing and quantity of this goal.

Participant 1- Someone decided that 1600MW is the right number. It could be more or less. Getting to the goal doesn't bother me, but it needs to be clear that this goal has some resemblance of what you need to ensure system reliability and an appropriate fuel mix. The NEM legislation that references

1600MW doesn't mention 2020 so I don't think we are held to that standard. If the incentives are aligned and we get there before then, then that's OK. The location of solar and how we are using DG are more important than goal. Should consider incentives on a locational basis. An example, Nantucket Electric needs power. They have almost no back-up power in summer. Not sure what the attitude towards solar is in Nantucket, but solar could alleviate this problem. An installation is worth far more to society there. There are likely many other places where this is the case. For ISO New England, peak electricity needs are after the sun sets. Solar is not giving us the full benefit we need. We'd better off orienting panels to pick up sun in later hours and incentivizing systems which provide maximum benefit to grid needs instead of maximizing production.

Participant 2- Agree with what was said, but also feels that the goal is too small. The program achieved the previous goal ahead of schedule. No one has demonstrated that there was negative impact from exceeding the previous goal. We've been very successful. Why are we setting this 1600MW goal? It's arbitrary. We can generate more solar power in a broad approach and include targeted installations. There's no need for one or the other or a real problem with exceeding the target.

Participant 1- The problem is that the program blew through the goal so fast, it signals that something isn't optimized. When you start getting to higher MW targets and higher costs, the grid might not be designed to handle that level of distributed power. The system has to be there to provide back-up service. In a perfect world would like to see system modernized, but that's not likely over the next few decades. Right now solar is not deferring generation or T&D. Cloudy days mean all of the solar users go back to drawing from the grid.

Participant 2- When I see there's that much work being completed, it is not necessarily a problem. That kind of program success is a good thing. Sure- maybe it needs to be directed and managed, and be used more efficiently, but we are not generating too much solar.

3. Perspectives on current net metering approach

Solar PV systems in Massachusetts typically benefit from net metering with various system sizes and configurations receiving different net metering benefits. Additionally, volumetric caps to net metering have been revised through legislation on multiple occasions over the past several years. Please provide your perspective on the current Massachusetts net metering approach.

Participant 1- It was a home run for us. The program should be kept.

Participant 2- On the 70% that you are not self-generating, it would be interesting to see how much extra you are paying on the 70% to get the lower rate on the 30%. You may pay additional fees on the 70% than the savings you receive from the 30%. Since you are offsetting such a large amount you are not likely to be generating overall savings. Might be more relevant for smaller systems

I am concerned that fixed costs of the system are not being served. I know people pursing CHP so they don't have to pay into adders and tariffs. Yet if CHP breaks down, they still need the grid. Any costs not paid by DG are picked up by everyone else. None of these customers are paying for EE programs, transmission, distribution, and low income programs. I know people that have gone completely off the grid, which has big implications in the short-term or long-term

Participant 1- Has always felt that the system of tariffs and rates are almost like the federal tax code. It's opaque. If we think that we as a society are moving towards RE and DG and that has an effect on distribution system, then that's a problem. We need to fix the tariffs. The system is creating disincentives for renewables

Participant 2- The utility system is 100-year old model. We have had piecemeal transformation.

Perspectives on current Massachusetts solar incentive model approach

Massachusetts solar installations typically benefit from a range of incentives, including SRECs, federal tax credits and net metering being major contributors to system economics. Please discuss your perspective on the current mix of incentives other than net metering (and virtual net metering) available to Massachusetts solar systems with a particular focus on the Massachusetts SREC incentive.

Participant 2- We have covered some of this. The system is a little bit complicated. Some municipal utilities have different ways of incentivizing solar. I don't know if it is better, but it is certainly simpler. My question is are we unjustly enriching the wrong people? Where do the benefits flow? We support members pursuing incentive programs, and our members comment that the system is confusing and it is always unclear if they are getting the best deal. It would be better in the long-run if MA was more similar to other states.

Participant 1 - Hoping to learn more about what's going on in other states through the task force process. In terms of the SREC program, the only thing I can say with confidence is that it is way too complicated.

Participant 2- I know that DPU is looking at TOU for basic service to push demand off-peak. I'm not a huge fan. Currently, solar is paid the basic service rate. Basic service is a price projection for next 3 o 6 months, while actual rate tends to be much lower. There is no reason why solar PV power being put into market should be compensated at a rate different from what it is worth, when you have to buy power at what it costs. You should get reimbursed for what the power is worth, and that would get rid of need for other programs.

4. Perspectives on other solar incentive models

Other states have implemented a range of incentive program types in order to grow their solar markets. Several program types that you may be aware of include (but are not limited to):

- *Standard offer incentive programs (aka. feed-in tariffs)*
- *Declining block incentive programs*
- *Competitive procurements (aka. auctions or solicitations)*

There are also many variations on these approaches, as well as co-policies. Are any of these incentive program types of particular interest to you? Please discuss your impressions of these or other incentive program types that you may be aware of, and whether we should focus on particular incentive types that are of interest to you. How do you think the effectiveness of these incentive program types vary for *different solar installation types (e.g. residential vs. utility scale)? What options would you like to see the consulting team consider and analyze for Massachusetts?*

Participant 2- Keep it simple. TOU rates, location-based compensation, or production-based compensation. Some municipal utilities compensate in this fashion, and it aligns the value of solar with its cost. The claim is that we are driving down the cost of solar, but there are protests when the incentive level is proposed to be dropped or needs to be dropped. It is unclear what's actually true, but if the incentives are aligned, like I said, I'm indifferent to the model.

5. Perspectives on future use of net metering, as well as minimum bill provisions

During the past year, efforts have been made to revise the framework for net metering in Massachusetts including the addition of a minimum bill for all electricity ratepayers. Please discuss your perspective on the future use of net metering/virtual in Massachusetts and, to the extent you are able, what options or changes would you like to see and why?

Participant 2- If people are compensated for the value of their power only, we wouldn't need a minimum bill, or if you are reimbursed your power costs only, then you would be paying for transmission and distribution costs only. National Grid and NSTAR are saying that someone has to pay for their back-up services, which means the transmission and distribution charge associated with your use of electricity.

Participant 1- There are a lot of elements and tariffs on the electric bill. The credit needs to only be for power portion, and then you can still fund these other programs. A possible exemption might be energy efficiency. The design of the incentive is to get people to use less traditional power, these programs aren't intend to make people use less solar or wind. Part of the incentive for solar should be that you might not have to pay that tariff. I'm not sure the credit should be stripped to just power.

Participant 2- We could have a different distribution tariff or schedule for on-site generation. Maybe you would pay a little less since you are not utilizing all of the programs. I tend to agree that just because you have solar or wind, that does not mean you should use less energy or pay into the efficiency fund. There are still environmental impacts from producing the systems. Our goal should be efficient use of energy period. If you have 5MW CHP system, and you briefly use the grid, you still have unlimited access to EE funds, even though they haven't paid very much into the system. Maybe we think about this further? We tend to look at these programs in a microcosm, but we need to look at all of the DG programs and their costs and think about reliability.

6. Perspectives on policy transitions

C. *At the 2nd Task Force meeting, it was suggested that analysis should account for **uncertainty costs**, (i.e., transition costs due to changing goals and programs.) Please discuss qualitatively the nature of these costs as you see them, and whether and how you might suggest such costs could or should be quantified. Are there particular threshold milestones where it might make sense to consider policy transitions in order to minimize such costs? What other means are available to minimize such costs?*

Participant 2- You can refer to my earlier comments. I have no problem grandfathering during the transition.

Participant 1- Agreed.

Stakeholder Specific

Please describe any concerns about low-income customer impacts and benefits of current Massachusetts solar policies. What changes could be implemented, consistent with overarching policy objectives, to mitigate these concerns?

Participant 1- Just an observation: Many low-income housing developments have ideal roofs for solar PV. The building uses practically little electricity and there's no incentive for the developer to pursue on-site energy. If there were, the energy could be used to reduce the low-income electric bills in the building, which would be a good thing. If we are incentivizing solar, then why not try to maximize benefit? Low-income customers are paying electric bills, they are subsidizing solar elsewhere and not being able to access programs seems unfair.

Participant 2- The incentives are completely misaligned for rentals.

Please describe any concerns about other customer impacts and benefits of current Massachusetts solar policies. What changes could be implemented, consistent with overarching policy objectives, to mitigate these concerns?

Participant 2- Cross subsidy is a problem to the extent that it is happening. Some people just aren't going be able to participate in the program and that is a problem

Participant 1- Even with ideal site conditions a system might not be cost-effective. It's not for everyone.

What are the expected potential impacts of Grid Modernization/Time-Varying Rates efforts on net metering value and framework?

Participant 2- This is what I discussed earlier. There is a loophole since that excludes competitively bid customers. Participant doesn't understand why solar wouldn't be subject to the same system as other generators. Has no problem paying solar generators a lot of money in the summer. We need to align TOU and smart grid with right incentives to build solar systems not for the sake of building them, but help solve reliability concerns.

Participant 1- I don't have an opinion on this yet.

9. Other topics

Are there any major topics or perspectives related to the Task Force's scope that we have not discussed today that you would like to comment on?

Participants offered no further comments.

Net Metering Task Force Focus Group Interviews
Group C- Solar Industry
1.20.2015
10:30 a.m.-12:00 p.m

- Bill Stillinger, PV Squared, Representing SEBANE
- Fred Zalcman, SunEdison, SEIA
- Janet Gail Besser, NECEC
- Lisa Podgurski, Representing urban solar installers
- Larry Aller, Next Step Living
- David O' Connor, SEBANE Kate Plourd, NECEC
- Geoff Chapin, Next Step Living
- Andy Belden, Meister Consultants Group
- Bob Grace, Sustainable Energy Advantage
- Kathryn Wright, Meister Consultants Group

Participants introduced themselves, and were informed the session would not be recorded. Participants were given the opportunity to provide additional written comments to supplement the call.

1. Stakeholder objectives and priorities from the Task Force process

What are your goals and objectives for the task force? Of those, what is your most important objective and why? To the extent that goals or objectives may conflict, how would you prioritize?

Participant 7: There is a document that lays out many of the objectives we have discussed as a solar industry coalition. It does a good job of capturing goals and priorities of several of the members. Provided consultant with documents via e-mail. The primary goal should be to ensure balanced growth of MA solar market for 1600MW and beyond. We should also support continued job growth in cost-effective way.

Participant 5: We need to get a good report and recommendations to the legislature to address net metering and solar incentives so we can hit the 1600MW goal in a timely fashion. We need to encourage other DG as well. Recognizes that utilities have raised concerns about distribution impacts, and the Participant is open to understanding and addressing their concerns. However in the long or shorter-term, there should not be caps. The incentives should be set-up to compensate for distribution impacts only. Hopes to find a win-win solution where EDCs can be partners in supporting DG.

Participant 4: The document Participant 7 referred to does lay out goals and objectives. If I were to prioritize, it would be to create a long-term sustainable market place for solar in the Commonwealth and break the cycle where we return to legislature to raise caps. This creates a lot of market risk for solar developers who are looking for stable, scalable market.

Participant 6: Seconds Participant 4. We can't keep returning to legislature if we want to have steady job industry growth. Maybe we should just remove the cap to prevent going through this cycle again.

Participant: We have simple feedback. We must ensure that the consultants and Task Force do what the legislature prescribed, except the March 31st deadline, which may have to be adjusted. The operating words from the legislature of a stable and sustainable market are important to everyone on this phone call.

2. Long term Massachusetts solar market goals

The current stated goal of the Massachusetts solar policies is to reach 1,600 MW of installed solar capacity in the 2020 timeframe. Please discuss your perspective on this MW goal, its timing, and the appropriate objectives for the state solar market beyond the timing and quantity of this goal.

Participant 1: 1600MW by 2020 has been discussed as a standard/goal we are moving towards, but given what's likely to happen with ITC expiration in 2017, this will not be linear process. We will walk most of the path before 2017, presuming no changes. How can we get to a point where the market is close to goal by end of 2016? We can get the rest of the way with lower incentive rate. For longer-term objectives, it would be ideal to have a stable policy approach and trajectory that initially provides a similar level of value to market participants and then have smooth transition to a stand-alone market after achievement of the goal. This would be similar to what was achieved in CA, but MA is at an earlier stage of market. Perhaps, in the 2025 to 2030 timeframe.

Consultant - What specifically do you mean when you refer to CA?

Participant 1- They took 8-years with their declining block schedule, and it stepped down over time. They still have net metering in place, which is important. The declining block drove significant market volume to develop the stand-alone market. MA is earlier on trajectory. The first step is getting to 1600MW goal without disrupting the market. Anything after 2016 has a 20-30% incentive cost due to expiration of federal tax credits.

Participant 7- Agrees with much of what Participant 1 stated. But, the end state should be self-sustaining market for solar. DOER has avoided boom-bust seen in other SREC markets. There has been more stable growth. Over the next two years, steady state growth is projected to 1600MW. Hopes to see reasonable industry (e.g. 15-30% CAGR) and job growth. We can reevaluate at the 1600MW point and see where solar is relative to grid parity. What incentives will be needed to get the rest of the way? Perhaps value of solar rates rather than incentives.

Participant is more focused on the transition to a new policy environment, and that we not further destabilize market by creating new constructs. Under SREC-II there are some markets where unfettered growth is possible, but most of growth in the market was under the managed growth sector, which is capped. Participant would suggest removing the cap on it before expiration of the ITC.

Participant 1: We will make a lot of progress towards the 1600MW is two years if the market is not interrupted. I think we are both focusing on allowing the market to continue to function without interruption and uncertainty through the end of 2016.

Participant 7- I would agree with that.

3. Perspectives on current net metering approach

Solar PV systems in Massachusetts typically benefit from net metering with various system sizes and configurations receiving different net metering benefits. Additionally, volumetric caps to net metering have been revised through legislation on multiple occasions over the past several years. Please provide your perspective on the current Massachusetts net metering approach.

Participant 1- Generally, we think the current NEM system is OK. A residential carve-out is a good idea, but community solar needs a carve-out too. We think community solar is a democratization of solar, and it should be a real priority. It fits new administration's goal of energy justice.

Participant 4- Agrees, and is supportive of the current NEM policy. We recognize that as solar penetration increases, different compensation schemes may be required based on a fair evaluation of system costs and benefits. This might be higher than retail value. With larger systems and VNEM systems, there's the loss of the distribution component. We will need to see where system is relative to utility distribution system load and where the value is created. Locational effects need to be accounted for in the next paradigm- currently all systems are treated equally.

Participant 6- In terms of NEM, we need to have it in MA, and we need to look at the caps. VNEM assures long-term stabilization of job and solar industry growth, which we need to keep in the mix.

Participant 5- Agrees with earlier statements. It would be useful to hear from consultants as to how policies in other states have dealt with utility concerns about distribution costs, and how to incentivize market as cost-effectively as possible. There are implications for the utility concerns about the distribution systems and our desire to remove caps.

Participant 7- Cap discussions in the legislature have been ongoing for several years. Utilities have traditionally made arguments that caps are technical caps for integration reasons. With 4185, the utilities were willing to remove the cap if they got a minimum bill. If we could get an idea of what is technically feasible for a solar penetration level from the utilities, it would be helpful. Minnesota said DG could serve 40% of retail load without major system impacts. In Massachusetts, we would be at less than 6%. It seems that this is an opportunity to explore technical constraints, if there are any.

4. Perspectives on current Massachusetts solar incentive model approach

Massachusetts solar installations typically benefit from a range of incentives, including SRECs, federal tax credits and net metering being major contributors to system economics. Please discuss your perspective on the current mix of incentives other than net metering (and virtual net metering) available to Massachusetts solar systems with a particular focus on the Massachusetts SREC incentive.

Participant 5- We have a variety of members with many business models. Our members favor many different models, so we won't weigh in on one. A key thing to consider for the task force and consulting team is if there are some models which are more efficient at achieving the same level of solar development? For all models, transition costs should be taken into account.

Participant 4- Our members were skeptical of the SREC program at first, and were concerned about the availability of long-term SREC off-taker agreements and incorporation of financial risk in the market. We have seen maturation of the market over past several years, financiers are getting more comfortable, long-term SRECs available and customers understand the market better. In total, many policy paradigms could support solar, but I think the MA model is promoting solar and delivering it. There may be tweaks to make the program more cost-effective.

Participant 1- The current SREC policy was positive even before there was an increase in natural gas generation. SREC-II was much better than the first SREC-I model due to increased certainty. Let's not change it by introducing risk and discouraging investors. SunRun and others pulled out dramatically when the program changed. We need to have clear market signals to make investors confident in the market.

5. Perspectives on other solar incentive models

Other states have implemented a range of incentive program types in order to grow their solar markets. Several program types that you may be aware of include (but are not limited to):

- *Standard offer incentive programs (aka. feed-in tariffs) – administratively set*
- *Declining block incentive programs – volume-based*
- *Competitive procurements (aka. auctions or solicitations) – competitive bids*

There are also many variations on these approaches, as well as co-policies. Are any of these incentive program types of particular interest to you? Please discuss your impressions of these or other incentive program types that you may be aware of, and whether we should focus on particular incentive types that are of interest to you. How do you think the effectiveness of these incentive program types vary for different solar installation types (e.g. residential vs. utility scale)? What options would you like to see the consulting team consider and analyze for Massachusetts?

Participant 3 - A lot of the prior comments answered this question. SREC-II seems to be working. Any changes to that system have to be done carefully and not destabilize the current knowledge base and certainty in contracting. Earlier NY, CT, and RI solicitation programs were mentioned. Those would be drastic changes for MA, which I'm not in favor of.

Participant 4- From our organization's perspective, all of these incentive programs have strengths and weaknesses. Without breaking it down further, we are generally more in favor of the incentive delivery mechanisms where the market is more or less continually open (declining blocks or SRECs). This means the market is not tethered to utility or a central administrator's solicitation process. There is a continuous business cycle, and developers are continuously selling projects. Greater transparency regarding incentive price is also helpful.

Participant 5- Many of our companies operate in different states. As you think about the analysis, stay focused on what's effectively delivering solar in different states.

Participant 7- Echoes previous comments. An open market that is not tied to a procurement schedule is key. Generally, other models only make sense to consider post 1600MW and not within the next two years where we could not change without significant cost. There has been in-depth work by the legislature and others to balance and achieve goals MA has for solar in the current program. We would be putting that goal achievement at risk. How much total uncertainty can the market absorb? The ITC will cause change in how tax equity participates. It will use a lot of bandwidth just dealing with that change. PBIs are like an SREC market with a firm floor. If there was a firm committed floor, then it is just about setting appropriate prices. As an additional thought for the legislature, reducing permitting, inspection and maybe interconnection costs could be an incentive for the market as well. A lot of the soft costs on residential side are due to massively fragmented requirements city-by-city in the state. If there's a way to consolidate, it might be worth putting on radar screen.

6. **Perspectives on future use of net metering, as well as minimum bill provisions**
   During the past year, efforts have been made to revise the framework for net metering in Massachusetts including the addition of a minimum bill for all electricity ratepayers. Please discuss your perspective on the future use of net metering/virtual in Massachusetts and, to the extent you are able, what options or changes would you like to see and why?

Participant 5- To the extent NEM can continue it should since it has supported development of solar. There are two concerns with that: cost effectiveness and distribution impacts. The QPQ of removing the cap is addressing the distribution concerns. We should work to resolve concerns.

Participant 1- A minimum bill that can be increased over time will make it hard to sell solar. It would need to be small and capped, otherwise it could kill the motivation to go solar. The biggest impact is in the summer, so the bill would need to be calculated fairly. Does not see a minimum bill as 100% necessary, but understands we need something.

Participant 7- An increasing minimum bill will destroy market security. It is unclear that a minimum bill will result in meaningful revenue to the utilities. The most at-risk members of the community may be impacted by a minimum bill, since low-income and elderly consumers are actively trying to reduce their bills. Overall the current NEM program is the best option that we have for progress through the end of 2016. The market will continue to evolve, and we will need a fair and balanced process of calculating the benefits and costs solar provides to the grid. It takes time. It was done well in Austin and Minnesota. Open to having a discussion on next generation approaches, but the process needs to be inclusive.

Participant 4- We supported 4185 last year, which did include consideration of minimum bills. Our support is contingent on an overall valuation of cost and benefits solar provides to customer, utility, grid, other ratepayers and society at large. Supports the notion of gradualism- any minimum bill has to be modest in amount relative to what customers are paying today. We are supportive of the concept if it's a trade for uncapping net-metering.

7. **Perspectives on policy transitions**
   D. *At the 2nd Task Force meeting, it was suggested that analysis should account for* ***uncertainty costs****, (i.e., transition costs due to changing goals and programs.) Please discuss qualitatively the nature of these costs as you see them, and whether and how you might suggest such costs could or should be quantified.*

E. *Are there particular threshold milestones where it might make sense to consider policy transitions in order to minimize such costs? What other means are available to minimize such costs?*

Participant 1- In any new market you will have less investment until the transition plays out, raising the cost of capital. Transitions need to be smoother. Once we pass 1600MW and the ITC fades, we need something to support the market to ease transition. It should not be radically different from the options in market now- we need companies and jobs not to be cut.

Participant 4- To the extent we do experience another change in the incentive delivery mechanism, we will need time for industry to adjust. Robust grandfathering is necessary to the extent investment decisions have been made based on the current market system.

Participant 7- Delays are a risk of transition since people will wait to see what will happen. SREC-II was not a major transition, but market grew 70% in 2013, and 2% in 2014. Without long-term visibility, any delays between now and the end of 2016 has a pretty clear cost. Any project delayed either loses 20% from the commercial ITC expiring or on residential side it loses 30% of its value. This is why it is of fundamental importance that the market be able to run through the end of 2016, unless we have some option that will provide 20-30% of the value of the system as an incentive. The transition needs to be a similar policy so the market can adjust. Any new program creates additional administrative burden.

Participant 3 - Grandfathering is fundamental to any contemplated change and as well as a long lead time.

Participant 4- It really is critical for customers now enrolled in NEM to continue to benefit from that arrangement. CA agreed that customers will continue to get NEM credits for the useful life of the system. This is critical for the market.

8. Stakeholder Group Specific

How (if at all) are FCM revenues currently monetized under the current policy environment? Do you have suggestions for improvements?

Participant 4- From our perspective, if the system is NEM, then the utility has the right to the capacity payment. But, for the most part, the utilities have not bid those assets in. There has been reluctance because of the capacity values to date. Utilities are also uncomfortable being subject to performance penalties from assets they don't own or control. This is detrimental to ratepayers- Close to 1000MW of solar is not being offered into capacity market. There could be a cost-sharing arrangement with developers to de-risk project from utility standpoint, or for developers to bid the projects in.

Participant 7- This is not relevant for residential. From our experience to date it is not something that has emerged as a revenue stream or service from a residential purchase. I am not familiar with everything the third-party market does. There may be early efforts on the third-party ownership side, but I haven't seen anything. The current market structure prohibiting pursuit of this, and customer knowledge of the FCM is low or non-existent.

Consultant – If obstructions were removed would FCM be of interest or are the risks too prohibitive?

Participant 4- We may be bidding resources in the next auction- so not at all. Right now, capacity rights belong to the utility- it is unclear if the utility may exercise those rights with more generation online or higher FCM prices.

What are your experiences in other state solar markets with alternative incentive models or policies in place?

No additional comments beyond earlier discussion.

What are the expected potential impacts of Grid Modernization/Time-Varying Rates efforts on net metering value and framework?

Participant 5- We sees significant opportunities to support DG deployment with TOU rates, and support TOU rates being made available. We need to send signals about the locational value of distributed resources. TOU can be a way to show that value. The value of solar and DG will be more available to system operators. This is something to keep in mind as policy changes, but not a near-term solution

Participant 7- Agreed. On residential side, TOU rates can expand the power and effectiveness of the solar market, but if done wrong way it could damage it. If customers can opt-in or opt-out of TOU rates, it could open up west-facing rooftop systems which have been previously unviable. If it's a mandated change with no grandfathering, it hurts customers who built their systems based on another rate structure.

9. Other topics

Are there any major topics or perspectives related to the Task Force's scope that we have not discussed today that you would like to comment on?

Participant 3- Must take public comment into account. There is a huge interest in preserving and expanding community-shared solar and equitable treatment for customers that are located in municipal power systems. No suggestions on how to move forward, but these have emerged as important.

Participant 7- During the analysis for SREC-II, there was a discussion of different program options. When thinking about residential customer-owned systems, having a more guaranteed value stream has no impact on their cost of capital. Their cost of capital is determined by their credit score. This is just to remind the team to be aware that investments to increase SREC cash flow security don't necessarily benefit residential solar. In the third-party market there are efforts by those players to line-up financing against those revenue streams.

Participant 5 - Look at solar incentive models that work for variety of ownership structures.

Net Metering Task Force Focus Group Interviews
Group D - Legislators
1.9.2015
10:30 a.m.-12:00 p.m.

Attendees:

- Christina Fisher –Senator Downing's Office
- Eric Krathwohl – Appointee of Senator Bruce Tarr
- Stolle Singleton – Appointed by House Minority Leader, Bradley Jones
- Andy Belden, Meister Consultants Group
- Kathryn Wright, Meister Consultants Group
- Bob Grace, Sustainable Energy Advantage

Participants introduced themselves, and were informed the session would not be recorded. One of the participants noted that they would have to leave the call early. Participants were given the opportunity to provide additional written comments to supplement the call.

1. Stakeholder objectives and priorities from the Task Force process

What are your goals and objectives for the task force? Of those, what is your most important objective and why? To the extent that goals or objectives may conflict, how would you prioritize?

Participant 3: The task force should find an ideal mix of solar incentives to meet state goals with a caveat that any incentives should be distributed equitably so there's no burden on non-participating ratepayers. There is a balance between meeting the goal and fairly distributing costs.

Participant 1: Shares similar view to Participant 3. Personally and through conversations with an elected official, the task force needs to define clear costs and benefits of future solar development. Personal opinion of reading of legislation seems like the primary goal of the task force is to figure out the best way to hit 1600 MW. Hopes task force can set up policy market or framework for market to continue to provide benefits going forward in the long-term that is clear and consistent to minimize boom-bust cycles seen previously in renewable markets.

2. What issues and concerns have your constituents expressed to you regarding the current net metering and/or solar policies?

Beyond the goal of meeting a solar target, what are any other policy objectives that are important for a solar and net metering program to provide?

Participant 2: Constituency consists of communities in Western Massachusetts that are active in solar market, and they felt that they were left out of the conversations during the last legislative session. They were also unsure about the minimum bill. The length and content of the final discussions about the bill also caused confusion. Constituents prefer to keep existing policies in place.

Participant 3: Emphasized the need for balancing incentives and costs, and a better understanding of ratepayer impacts. Balance of incentives and ratepayer impacts are needed. Low-income individuals also need to be able to access solar DG programs through avenues like virtual net metering.

Participant 1: Based on personal conversations with the community, there is more interest in more solar. Participant's state legislator would like to see more fairness, and recognizes growing interest in community solar. Programs need to be available to more people. Other goals to consider include economic development and jobs. The MassCEC has shown growth in employment in the clean tech sector in the state. Have to consider this issue- was not sure if the report to the taskforce will include impacts from additional solar development, but it is important.

3. Long term Massachusetts solar market goals

The current stated goal of the Massachusetts solar policies is to reach 1,600 MW of installed solar capacity in the 2020 timeframe. Please discuss your perspective on this MW goal, its timing, and the appropriate objectives for the state solar market beyond the timing and quantity of this goal.

Participants did not have comments on this question

4. Perspectives on current net metering approach

Solar PV systems in Massachusetts typically benefit from net metering with various system sizes and configurations receiving different net metering benefits. Additionally, volumetric caps to net metering have been revised through legislation on multiple occasions over the past several years. Please provide your perspective on the current Massachusetts net metering approach.

Participant 3: Believes that volumetric caps are necessary under the current structure since participating and non-participating ratepayers are funding incentive programs. Unless the structure is readjusted then the cap can't be adjusted or lifted. This could be done by changing the credit level, for instance potentially crediting solar production at the wholesale rate. A minimum bill could also be explored to recover appropriate costs from solar customers. Does not think the current structure is ideal.

Participant 1: Agrees that the current structure is not ideal. Caps have created boom-bust cycles and rushes to the queue without having viable projects. Programs fill up quickly and then development cycle halts. Can we eliminate caps? Studies are needed on DG and distribution system impacts as well as appropriate pricing for incentives. To the extent the net metering task force study and report could help refine these questions- it would be helpful. People are OK with paying their costs- a minimum bill might work. Virtual net metering has also been important driver for many projects. This needs to stay in place.

Participant 2: After listening to public comments, thinks virtual net metering is of significant concern across constituencies.

5. Perspectives on current Massachusetts solar incentive model approach

Massachusetts solar installations typically benefit from a range of incentives, including SRECs, federal tax credits and net metering being major contributors to system economics. Please discuss your perspective on the current mix of incentives other than net metering (and virtual net metering) available to Massachusetts solar systems with a particular focus on the Massachusetts SREC incentive.

Participant 3: Refrained from commenting since Participant was unclear of the program's performance.

Participant 1: The consultants may be able to help clarify. SREC-I and SREC-II have been critical to solar development. When SREC-I was depleted and SREC-II was not yet in place, development virtually halted. Everyone was waiting on the policy changes. Believes the current targeting strategy to encourage higher-value installations makes sense. The federal tax credit will expire soon- unless replaced, there will be a void. Unsure of how and if the state can deal with that in advance, but the loss of the incentive will have impact on development.

Participant 2: Had to leave the call.

6. Perspectives on other solar incentive models

Other states have implemented a range of incentive program types in order to grow their solar markets. Several program types that you may be aware of include (but are not limited to):

- *Standard offer incentive programs (aka. feed-in tariffs)*
- *Declining block incentive programs*
- *Competitive procurements (aka. auctions or solicitations)*

There are also many variations on these approaches, as well as co-policies. Are any of these incentive program types of particular interest to you? Please discuss your impressions of these or other incentive program types that you may be aware of, and whether we should focus on particular incentive types that are of interest to you. How do you think the effectiveness of these incentive program types vary for different solar installation types (e.g. residential vs. utility scale)? What options would you like to see the consulting team consider and analyze for Massachusetts?

Participant 3: Interested in declining block incentives to encourage solar at lower cost. Wondered if it was possible to adapt California and New York models for Massachusetts. Inquired on how competitive procurement applies to small-scale solar projects?

Participant 3: Standard-offer contracts offer price certainty, but setting appropriate price over time is difficult.

Participant 1: Expressed general familiarity with models, but not enough to comment specifically. Looks to consultants for guidance on these topics.

7. Perspectives on future use of net metering, as well as minimum bill provisions

During the past year, efforts have been made to revise the framework for net metering in Massachusetts including the addition of a minimum bill for all electricity ratepayers. Please discuss your perspective on the future use of net metering/virtual in Massachusetts and, to the extent you are able, what options or changes would you like to see and why?

Participant 3: Would be supportive of a minimum bill if an ideal price can be identified that supports solar development without cost shifts. Will the consulting identify an appropriate amount? Participant heard there was limited quantitative analysis on the bill during the last session.

Participant 1: Net metering and virtual net metering are key to solar development. It seems likely that a reasonable rate could be set. The legislation could develop a framework to be administered by DOER to adjust the bill over time. development, but needs to not be burdensome. Unsure if minimum bill would be helpful or appropriate.

NMTF Consultant: Can we get feedback on degree to which grandfathering is appropriate for those who invested in solar?

Participant 1: Would have a problem applying new charge to those who've made investments from a legal and fairness perspective.

Participant 3: It makes a difference if it's a rate adjustment vs. minimum bill. Grandfathering a rate adjustment would seem more fair if the rate reflects the cost

Participant 1: Agreed. Looking at it as a homeowner with solar, to the extent that bills are offset, Participant would find it fair to charge for use of distribution system. The rate just needs to be correct. Will there be an analysis of the net metering credit rate in other states?

8. Perspectives on policy transitions

F. *At the 2nd Task Force meeting, it was suggested that analysis should account for* ***uncertainty costs****, (i.e., transition costs due to changing goals and programs.) Please discuss qualitatively the nature of these costs as you see them, and whether and how you might suggest such costs could or should be quantified.*
G. *Are there particular threshold milestones where it might make sense to consider policy transitions in order to minimize such costs? What other means are available to minimize such costs?*

Participant 3: There will be costs to a transition, but the current system also has costs as well, and the state still has a target to achieve.

Participant 1: To the extent possible, we must avoid having multiple transitions. If the taskforce can establish a framework for a longer timeframe, it would add some certainty. Policy changes lower investor confidence. How do you quantify initial policy transition cost? Unclear if that analysis is feasible.

Participant 3: Seconds Participant 1. Need to develop longer term, predictable model for future for investor confidence and market development.

Other topics

Are there any major topics or perspectives related to the Task Force's scope that we have not discussed today that you would like to comment on?

Participant 3: There've been recent reports about solar reaching grid parity in certain sectors. How have incentives impacted this? Has this or should this be discussed at the meetings?

Participant 1: Taskforce already has a lot on its plate, and doesn't have anything to add. Heard solar has reached grid parity in utility-scale projects, but since we are focused on smaller systems shouldn't influence conversation or actions much.

Net Metering Task Force Focus Group Interviews
Group F- Non-Task Force Members
1.15.2015
10:30 a.m.-12:00 p.m

Attendees

- Emily Rochon, MassSolar, Boston Community Capital
- Nathan Phelps, Vote Solar
- Todd Ford, Hampshire COG
- Craig Wetmore, Bluewave
- Becky Merola, Noble Solutions
- Jason Prince, Karbone
- Stephen Eisenberg, SREC Trade
- Stephen Pratt-Oro, Eastern Bank
- Andy Belden, Meister Consultants Group
- Kathryn Wright, Meister Consultants Group
- Bob Grace, Sustainable Energy Advantage

Participants introduced themselves, and were informed the session would not be recorded. Participants were given the opportunity to provide additional written comments to supplement the call.

1. Stakeholder objectives and priorities from the Task Force process

What are your goals and objectives for the task force? Of those, what is your most important objective and why? To the extent that goals or objectives may conflict, how would you prioritize?

Participant 5: The objective is to develop sustainable policy for solar now and in the future. Policies should be substantive enough to include technologies and reach 1,600MW goal.

Participant 4: Agreed with Participant 5, and added than an explicit effort be made to include low-income communities and ratepayers, and creating a sustainable market beyond 1,600MW.

Participant 7: Agreed with previous statements. The Net Metering Task Force (NMTF) also needs to ensure development is completed as cost-effectively as possible. It helps everyone if solar is subsidized as efficiently as possible, and puts less of a burden on ratepayers.

Participant 1: The NMTF needs to take current market infrastructure into consideration from the financing of installations to service providers. The structure of the market, be it net metering or the SREC program, should change such that it does not impact market development or cause a market disruption. The policy also needs to be as cost-effective as possible. Current market has enabled Massachusetts to become market leader in solar and has led to a number of clean energy jobs in the state.

Participant 8: Coming from the perspective of the retail electric market, existing retail contracts need to be acknowledged and considered before changing the RPS.

Participant 2: Cautions and reminds NMTF that wind energy projects in the state are not currently on track. Continued incentives for solar become more important since other renewable energy projects are not performing as well.

Participant 9: Agreed with comments about stability. State needs to live with this model for a long time and aim for market stability. Encourage NMTF to observe the leadership role of municipalities have taken and seek to retain that leadership

Participant 6: The market needs stability, and existing projects and projects in pipeline should be grandfathered.

2. Long term Massachusetts solar market goals

The current stated goal of the Massachusetts solar policies is to reach 1,600 MW of installed solar capacity in the 2020 timeframe. Please discuss your perspective on this MW goal, its timing, and the appropriate objectives for the state solar market beyond the timing and quantity of this goal.

Participant 4: 1,600MW is too small in light of the diverse market that SREC-II is trying to foster. Given the MWs developed in the previous years, DOER has had to throttle the managed growth sector. This impacts economic growth. 1,600MW is only 4% of electricity consumption in state. Need to think about the next stage of the market. Task force also needs to take into account the impacts of the Investment Tax Credit (ITC) expiration.

Participant 9: The target is fine, but it is only one piece of the pie. Much of the money associated with solar development in past few years has flowed out of the state. Need to incentivize jobs and business within the Commonwealth instead of supporting the multi-national companies which have entered the market.

Participant 7: 1,600MW is not enough of a high ceiling for development. The key idea is to foster development where it is cost-effective, and developers can build what they can to respond for the benefits of the GWSA and ratepayers. Fears that 1,600MW target throttles development instead of encouraging. Needs to be clear if it is a binding constraint or an aspirational goal.

Participant 6: Agreed with previous statements. Noted that as we consider other questions, that the stated goal acts as a cap. 1,600MW is too small. Incentives should be a matter of right for developers that deliver solar instead of facing caps.

Participant 5: 1,600MW is the next interim objective, but not the goal. More development can benefit all ratepayers.

Participant 6: MW goals and program caps create unintended dynamics. There is positive intent to spur development, but can lead to boom-bust cycles, and doesn’t allow for smooth continuation of market development. Seeing that with managed growth sector of SREC-II program. In other states, the solar carve-out is a percentage of retail load served.

3. Perspectives on current net metering approach

Solar PV systems in Massachusetts typically benefit from net metering with various system sizes and configurations receiving different net metering benefits. Additionally, volumetric caps to net metering have been revised through legislation on multiple occasions over the past several years. Please provide your perspective on the current Massachusetts net metering approach.

Participant 5: Before any discussion starts, we need better information. A cost benefit analysis is the first step, then we can evaluate NEM and NEM vs. other policies. Also need to consider NEM in the context of the current rate design. If the rate design changes, is NEM still appropriate?

Participant 4: Agreed with Participant 5. As it stands now that caps are created by statute and we have to return to legislature to raise cap. This creates uncertainty. Should be addressed by removing cap entirely or removing for smaller projects. Move from a 25 kW exemption to 1MW exemption. Virtual Net Energy Metering (VNEM) needs to be evaluated not just in terms of utility costs, but to insure that all ratepayers can access solar.

Participant 7: Agrees with comments on VNEM. NEM and VNEM has been fundamental to development of solar in the state. This has to be taken into consideration in the cost-benefit analysis. VNEM allows concerns with NEM to be addressed by allocating credits to wider population. Have seen issues in Minnesota where cost-benefit analysis has made utilities reluctant to adopt. Need to look at benefits with MA in mind. Need policy not to stop and start as we have seen with PTC elsewhere.

Participant 1: When H4185 was being debated some of the benefits that DG is providing to the grid, like capacity, were not focused on. Wants to make sure consulting group considers benefits, and the need for additional grid supply projects with traditional generators coming offline. This benefits ratepayer base as well.

4. Perspectives on current Massachusetts solar incentive model approach

Massachusetts solar installations typically benefit from a range of incentives, including SRECs, federal tax credits and net metering being major contributors to system economics. Please discuss your perspective on the current mix of incentives other than net metering (and virtual net metering) available to Massachusetts solar systems with a particular focus on the Massachusetts SREC incentive.

Participant 4: SREC-II added the tiered SREC factor to favor projects over others, such as projects in low-income communities and housing developments. This has created a major market where there previously was none. But, the SREC-II process can be too rigid. Under SREC-I, we completed a shared solar project, which sold power to assisted living, center, housing project and local business. SREC-II can't look at this project with different actors and assign it appropriate value. Unintentionally excludes interesting projects- you don't get as good of an incentive. Stifling innovation. Would be nice to address this inflexibility.

Participant 9: SRECs have driven the Massachusetts market. The Commonwealth shouldn't be wedded to this policy, but should not exclude it as an option. Should use this opportunity to test out other models, but the status quo may not be the best option. Not being able to secure financing for future value of RECs is a problem.

Participant 7: Need to make sure we have an efficient subsidy regime. Believes market mechanism is the most efficient way to achieve that. Administratively-set incentives haven't worked because they aren't responsive to market forces. From the market-makers perspective, and in response to previous comment, there have been long-term hedges in the Massachusetts market. SRECs in Mass are supported by policy features- dynamic demand calculation, floor, and auction. This means the SRECs are less volatile, and thus long-term SREC hedges are provided. People have been able to get financing. SRECs and NEM are broad policies but have to look at Massachusetts context. SRECs has encouraged development efficiently here. Market will do well if stability and path forward is clear.

Participant 10: Capital costs for Massachusetts are in the higher-range from a cash equity and tax equity perspective. This is partially because of the SREC market- thus would encourage other models. Capital costs are less in other places where incentive regime is simpler (i.e. California). In practice Massachusetts is 300-400 basis points higher because of the uncertainty of SREC transactions. Some companies can operate, but it's a heavier lift.

Participant 6: Likes SREC program. Long-term SREC pre-sales are significantly below spot prices. From our perspective- there are downside and upsides. Upsides: Does benefit local vendors and in-state/in-market actors. Downsides: SREC program opacity, even the auction and market are downside to program. Value leakage from developers/ratepayers over to brokers, etc. (i.e. Attorneys who are now needed soft costs under SREC program).

Participant 9: Need to differentiate large-scale SREC process vs. residential projects. To individuals - SREC market swings wildly and homeowners have no market power. Need some more protection for residential scale SRECs holder to keep small-scale SREC market viable for homeowners.

Participant 1: In the consulting report for SREC-II, the way the incentive flows from buy-side to sell-side means that one-side of the market can be more incentivized than the other. But it's a market-based mechanism so it can be responsive. Price is influenced by other factors not just solar supply in the market, but electricity costs, other incentives. If the value of the incentive is fundamentally too low, projects will slow down, and the SREC price will increase since there won't be enough to meet demand. No legislative process to go through make changes. Understands that these price swings have happened in large drops- think there's elements to adjust volatility to adjust the market.

Going back to the 4185 process: If we used declining block incentives, solar would be in its own incentive program separate from other renewables. Market should be used to incentivize renewables just like the electricity market uses competition. Ultimately SREC-I and SREC-II will turn to Class-I RECs- its the same type of program as opposed to something radically different.

5. Perspectives on other solar incentive models

Other states have implemented a range of incentive program types in order to grow their solar markets. Several program types that you may be aware of include (but are not limited to):

- *Standard offer incentive programs (aka. feed-in tariffs)*
- *Declining block incentive programs*
- *Competitive procurements (aka. auctions or solicitations)*

There are also many variations on these approaches, as well as co-policies. Are any of these incentive program types of particular interest to you? Please discuss your impressions of these or other incentive program types that you may be aware of, and whether we should focus on particular incentive types that are of interest to you. How do you think the effectiveness of these incentive program types vary for different solar installation types (e.g. residential vs. utility scale)? What options would you like to see the consulting team consider and analyze for Massachusetts?

Participant 5: Feed in tariffs don't do much to change the customer's interactions with electricity. Seen as financial investment. Declining block- great for financing and helps reduce soft costs. Sets market expectation for value of solar will be lower and heading toward parity. Competitive procurement- should only be used for utility-scale solar, not appropriate for DG or customer-sited solar.

Participant 4: Agrees with Participant 5's thoughts on competitive procurement. Many ways to incentivize solar, but unless we see something better than SRECs, prefer current system. Would say stay away from buy-all and sell-all transfers hedge value from customer to ratepayer. Participant has sold net metering credits/electricity for low-cost electricity over the years. Savings and hedge value in combination is appealing. If you remove the hedge, takes away incentive for low-income communities to go solar.

Participant 6: If it's a goal of the program to incent in-market vendors and program, the tariff would eliminate local market in favor of larger companies. Under the procurement model a developer trying to contract would not want to have bids from unbuilt projects. Doesn't think solar would grow under this model.

Participant 1: Procurements are at specific point in time. If you don't have everything in place at time of procurement, you have to wait. Competitive procurements have their own administrative cost burden. Notes per SREC fees for open markets is less than costs for competitive procurement. If the administrator of the program is an IOU or specific provider, they may manage market for long-time – this is not competitive. If there is something wrong with the administrator of the program, then not much you can do. In SREC states, brokers competes with other service providers to manage SRECs.

Participant 7: Agrees previous comments. Competition is the name of the game. Administratively set rates are problematic. Declining block is great because acknowledges declining installed costs of solar over time, but many other factors to take into consideration as well. SREC-II mechanism has declining auction-price. Current system also assumes decreasing costs and has some of benefits of a declining block program. Competitive procurement is new can of worms. Stability is the crux to continue development. Utility-scale systems just figured out the new SREC market- revamping again, will have bad short to mid-term implications. In summary, markets are more efficient with competitive mechanisms.

6. **Perspectives on future use of net metering, as well as minimum bill provisions**
   During the past year, efforts have been made to revise the framework for net metering in Massachusetts including the addition of a minimum bill for all electricity ratepayers. Please discuss

your perspective on the future use of net metering/virtual in Massachusetts and, to the extent you are able, what options or changes would you like to see and why?

Participant 4: Grandfathering goes without saying. We can't treat existing systems differently from how they've been treated; it disrupts financial stability and market security. 4185: Differentiated between NEM and VNEM, and somehow distinguished that VNEM electricity was worth less. This is too broad a distinction. A behind-the-meter triple-decker solar installation in Dorchester would be worth less under 4185. No proof that VNEM systems provide less value to the grid. Many low-income communities live in shared-multi-family housing. Treating VNEM and NEM projects separately brings up questions access. Maybe look at size limitations? Not appropriate to assume all VNEM projects are being over-subsidized, but maybe some of the larger projects are. Large here meaning multi-MW. 4185 proposed a lower incentive value based on electricity prices with additional cash to ensure projects would be developed. A lot of the affordable housing developments are limited in the amount of cash they can receive. Third-party providers would not be able to give cash for solar. Have to be careful about changes to the policy which might destroy certain market segment.

Participant 4 submitted comments on minimum bill submitted at hearing.

Participant 5: Need to discuss what the problem is right now or if there is one, then we can discuss solutions. Minimum bills are a solution to a problem, but we aren't sure what problem we are addressing. Structure: Should only cover the fixed costs to serve that customer. Excludes electric distribution system costs.

Participant: In 4185 discussions over the summer, benefits facilities provided were discounted. Many of these facilities cannot participate in capacity market. Agreed with Participant 5 on minimum bills. There may be other models out there, but unsure what they are. As retail electricity sales go down, utilities will hurt. How do we incentivize IOUs appropriately to maintain grid services going forward? Need to think about using EDC infrastructure as a platform to innovate onto.

7. Perspectives on policy transitions

- H. *At the 2nd Task Force meeting, it was suggested that analysis should account for* ***uncertainty costs****, (i.e., transition costs due to changing goals and programs.) Please discuss qualitatively the nature of these costs as you see them, and whether and how you might suggest such costs could or should be quantified.*
- I. *Are there particular threshold milestones where it might make sense to consider policy transitions in order to minimize such costs? What other means are available to minimize such costs?*

Participant 5: Determine the risk and the value of uncertainty in the transition. Installed costs would increase based on uncertainty of a policy transition. This would vary based on the clarity of the transition plan. With perfect information, the transition should be painless. However, with an abrupt transition, uncertainty costs will be much higher. Other costs should include lost jobs.

Participant 10: During SREC I to SREC II transition, we saw capital providers leave the market. The ones remaining can charge a premium for their financial services. From the financing perspective, you could figure out the cost based on few equity providers in the market. We can put something together. If capital costs rise, then installed costs are impacted by X%.

Participant 6: The assumption Participant 10 is making is that at some cost of capital, good projects can still get done. But, in our observations, if cost of capital goes up, projects don't happen. Market disruption means you don't get all the benefits of the program until certainty is restored. You probably won't get much development.

Participant 4: From a non-profit developer perspective, increased project lead times, lead to more costs. Does not impact ratepayers directly, but reduces savings to end-users. If you spend 10% more on soft costs, then instead of selling cheaper electricity, you have to sell it at a higher price for the costs to pencil.

Participant 7: Seems counter-intuitive: SREC criticisms are based on market volatility. Yet changing the program will cause more instability. Higher cost of capital are being exacerbated by talking about changing the policy. If there had to be a transition, the earlier comments make sense. Look at the transition from SREC-I and SREC-II. Price point was at the ACP is because development stopped because of the uncertainty.

With regards to quantification: Quantify impacts with proxies such as jobs, or electric prices, gas price volatility. There are usually milestones to consider a transition. The time is not now. 1,600MW is an interim target. Let SREC-II play out- the rules recently changed. Suggests removing managed growth and net metering caps. Will hit the interim target before 2020, under these conditions. Give enough lead-time to market about what transition period will be.

Participant 4: If we play out the legislative and regulatory process, realistically the rules would be changed by 2017, which only leaves 3 years. SREC-II is sunsetting at 1,600MW. Keep calendar in mind for the transition.

Participant 1: If you cut-off SREC-II before the interim target, there will be consequences: Will push market into a sunset period sooner. Currently an increase in prices for 2015 and 2016 vintages of SREC-I. SREC-II will push price up faster market thinks it is ending

8. Other topics

Are there any major topics or perspectives related to the Task Force's scope that we have not discussed today that you would like to comment on?

Participant 5: Cost benefit analysis is extremely important. To the maximum extent possible we need to quantify benefits of solar. If help is needed, they have examples from other states.

Participant 4: Significant loss of generation assets is coming. We are either paying more for natural gas or for transmission lines. Solar is the only renewable resource in MA that has the potential to grow quickly and offset some of this need. The cost of not building solar is not zero.

Participant 9: Focus on retaining as much of the positive economic impact within the Commonwealth.

Net Metering Task Force
Focus Group Interview Questions
Written Responses of National Grid
January 26, 2015

Executive Summary

National Grid appreciates the opportunity to provide these written comments. We are fully supportive of the 1600 MW solar photovoltaic (PV) goal by 2020. While this is an aggressive goal, we are confident that the Commonwealth will achieve it. Importantly, we believe that the Commonwealth can achieve it in a more cost effective way than our current structure allows.

Net metering, which may have been appropriate to jump start this important market, is not sustainable in the long run. Indeed, if Massachusetts were ever to achieve wide-scale solar deployment, with solar panels on every roof, with all customers net metering, there would be no one left to pay for the distribution system on which all of those customers would still rely for services, whether the solar facility was generating or not. This shows how important it is to develop the right long-term, sustainable construct, so that we can benefit from solar PV and other renewables without creating new problems.

In particular, National Grid notes that a virtual net metering (VNM) facility, where a customer is generating electricity in one location and applying net metering credits at an altogether different location, is far removed from the original concept of net metering, which was to allow the netting of behind the meter generation from the usage at that same location. As a result of the current net metering rate design, VNM systems result in a much higher cost to distribution company customers than if the generation were behind the meter.

Solar is also supported through additional incentive payments for solar renewable energy credits (SRECs), which have been provided regulatory price supports that have been higher than needed to build solar, and far more than being paid in other states for similar incentives. Plus, the instability of the value of solar renewable energy credits (SRECs) imposes higher costs on owners of solar installations than other support mechanisms, as they are unable to borrow as much to fund the development of the installations from financial institutions that value a stable source of revenue. As a proven, low-risk, and predictable generation resource, solar PV should be paid for with a low-risk revenue stream, to reduce the cost of financing as much as possible.

The right incentive program will enable the development of a resource like solar PV at the lowest cost to non-participants, paying no more subsidies than are necessary in a transparent, simple and administratively efficient way. The use of standard performance-based incentives, publicly set ceiling prices, competitive processes for larger systems, and tariff-based payments could together create the right solar support mechanism to achieve the stated goals.

Net Metering Task Force – Focus Group Interview
National Grid Responses
January 26, 2015

1. Stakeholder objectives and priorities from the Task Force process

What are your goals and objectives for the task force? Of those, what is your most important objective and why? To the extent that goals or objectives may conflict, how would you prioritize?

National Grid's main goal for the net metering task force is to develop agreement on a sustainable future for renewable energy generation in an integrated distribution grid. A sustainable future is one where the renewable programs are: (1) delivered at least cost to customers; (2) easily administered; (3) supported by appropriate cost recovery from all customers, including those with renewable energy generation, for the services they are receiving from the grid; and (4) provided in a transparent, competitive, and cost effective manner that considers all incentives available. At present, Massachusetts is paying more for solar energy than its neighbors, and this is unnecessary and unfair to those footing the bill.

Net Metering Task Force – Focus Group Interview
National Grid Responses
January 26, 2015

2. Long-term Massachusetts solar market goals

The current stated goal of the Massachusetts solar policies is to reach 1,600 MW of installed solar capacity in the 2020 timeframe. Please discuss your perspective on this MW goal, its timing, and the appropriate objectives for the state solar market beyond the timing and quantity of this goal.

National Grid views the 1600 megawatt (MW) by 2020 goal as an aggressive, but achievable goal. The 1600 MW target will provide about of 4% total energy supply and represents 14% of historic peak demand as measured for net metering purposes in Massachusetts. The goal is aggressive in light of the industry development needed to install this amount of solar, the changes required at utilities to interconnect and manage this amount of solar, the complex customer management for both developers and utilities that is part of that expansion, and the overall cost of the investment in solar, estimated in the range of $5 billion to $6 billion.

National Grid supports the timeframe for reaching the goal. However, as with the first phase of the Solar Carve-Out certificate program (SREC I), which sought to develop 400 MW by 2017, we believe this goal will also be met earlier than expected because of the high incentives provided to solar owners in the combination of net metering and SRECs, along with the current allowance of VNM. The regulatory construct for VNM is allowing developers to choose low cost locations, receive very high value for their output, and use the distribution system for free to deliver their product to their credit purchasers.

National Grid feels strongly that transitioning to minimum bills, and potentially to a more disaggregated rate design, as described in the answer to Question 6, could better align the value and benefits provided and received by all solar PV, to create a more sustainable future for the use of this important resource, and still make the goal within the 2020 timeframe. Moreover, changes in solar policy overall are needed to lower the total cost of the Solar Carve Out program, or any successor to it, and reduce the cross-subsidies associated with net metering, so that more net benefits (or a smaller net cost, if benefits are less than total costs) are enjoyed by all of the state's residents. This would also have the beneficial effects of reducing payments to solar developers and their investors, whose beneficiaries are largely out of state, and keep a larger proportion of the benefits of solar development for the citizens of the Commonwealth.

3. Perspectives on current net metering approach

Solar PV systems in Massachusetts typically benefit from net metering with various system sizes and configurations receiving different net metering benefits. Additionally, volumetric caps to net metering have been revised through legislation on multiple occasions over the past several years. Please provide your perspective on the current Massachusetts net metering approach.

In discussing the value of net metering credits, the above statement appears incorrect. In Massachusetts, most of the large net metered systems receive the same value of credits (albeit in greater amounts) as the smallest net metering systems, because a customer's rate class is presently assigned on the basis of on-site usage, rather than the volume of energy exported or connection size. Furthermore, net metered systems that are coincident with load receive the same value of credits as those that are not coincident with load. This means that a customer who could establish a solar facility to actually serve some portion of its load has a disincentive to do so, if it would be more remunerative to separately meter as a VNM system.

These details highlight how net metering may have been an acceptable way to "jump start" an important market, but is inappropriate for the long term and should be changed now. Customers who net meter can, with enough output or credits, avoid paying for the services they are receiving from the distribution utility, which include: (1) delivery of excess output; (2) provision of voltage; (3) system stability; (4) delivering instantaneous power requirements in excess of generation capability; and (5) backup power when self-generation is unavailable. If all of National Grid's customers were to put solar on their roofs and net meter, no one would be paying for the distribution system that they are all using for these services,. This highlights the inherent flaw with net metering and why we must find an alternative if we want to have a sustainable renewable energy future.

The amount of the net metering credit, based on the sum of distribution and commodity prices, is divorced from the reality of any benefit these facilities are providing. This is especially true in Massachusetts which also provides considerable value for a solar array's unique, renewable attributes through solar renewable energy certificate (SREC) support. Furthermore, customers who do not partake in solar development and net metering are picking up these costs, placing an unfair burden on them.

As explained above, a key net metering benefit in Massachusetts is VNM, a tool that promotes renewable generation by allowing a customer to generate electricity in one location and capture credits a high volumetric rate, and then apply those credits to at a location that is taking electric service at a less-volumetric rate. As such, the current rules create a type of "arbitrage," which incentivizes customers and developers to maximize revenue by locating a generating facility as a separate account in a separate location instead of behind the customer's load and meter. This is far removed from the original concept of net metering, which was to allow the netting of behind-the-meter generation from the usage at that same location. VNM also results in a much higher cost to distribution company customers largely due to the way the energy is sold at the generation site for wholesale value to the ISO-NE, while the receiving account is still served as a full-requirements load. National Grid's analysis shows that VNM facilities cost our customers more than behind-the-meter facilities that offset a customer's electricity load in "real time." Using rates now in effect, it will cost all of our customers approximately $70 million dollars per year to subsidize a nine percent net metering cap that consists of VNM facilities, compared to approximately $40 million per year if all facilities were behind the meter, approximately 75 percent more.

Thus, a customer is given a powerful incentive to install a VNM facility instead of a behind-the-meter facility, and no incentive to reduce actual electricity load. Essentially, this is an accounting construct that promotes the development of renewable energy projects and allows a minority of customers to avoid all cost responsibility for supporting the distribution system on which they rely.

4. Perspectives on current Massachusetts solar incentive model approach

Massachusetts solar installations typically benefit from a range of incentives, including SRECs, federal tax credits and net metering being major contributors to system economics. Please discuss your perspective on the current mix of incentives other than net metering (and virtual net metering) available to Massachusetts solar systems with a particular focus on the Massachusetts SREC incentive.

The Solar Carve-out within the Massachusetts RPS creates demand for SRECs, the design of which has posed a much higher cost on all customers than was needed for the development of solar PV. In addition, the instability of the value of SRECs imposes higher costs on owners of solar installations than other support mechanisms, as they are unable to borrow as much to fund the development of the installations from financial institutions that value a stable source of revenue. As a proven, low-risk, and predictable generation resource, solar PV should be paid for with a low-risk revenue stream, to reduce the cost of financing as much as possible.

The Solar Carve-out design has several elements that resulted in the high cost approach. This is especially true for the SREC I program. First, the maximum value for SRECs, determined by the SREC Alternative Compliance Payment schedule, was administratively set at a time when solar PV cost much more to install. It was then insensitive to rapidly declining costs, and remained insensitive during periods of shortages of SRECs. This critique also applies to the Solar REC Clearinghouse Auction price in the regulations, which was set at $300 and has not been altered. The SREC II program improved on these elements by creating a lower and declining ACP and auction price schedule. In addition, the new program introduced the SREC factoring approach, whereby a MWH generated is multiplied by a percentage to determine how many SRECs that hour of generation has produced. This had helped bring the costs of Phase II of the Carve-out program down compared with Phase I on a per MWH basis.

However, the SREC program as a whole is still higher in cost than other options, even under SREC II. Competition based on price for total production value by the developer/owners of mid-sized and larger solar facilities would likely push the total cost of solar subsidies down to half of the current level. This pricing level has been seen in other states that have used competitive programs, which will be detailed further in the answer to Question 5. In addition, SRECs and net metering credits are not linked in Massachusetts in a total value. This means that when SREC costs and energy costs are both high – such as the current period – the amount being paid in total to existing systems is very high. By contrast, a fixed price allows the SREC, or incentive, portion of the payment to shrink as the per kWh value of delivered energy rises.

In short, the SREC structure of the Solar Carve-out established a high-cost, high-risk policy support mechanism that was designed to induce a surge in investment activity, which was then difficult and slow to revise when solar development costs declined sharply. While improved upon in Phase II, the program uses a higher cost and higher risk approach than a support mechanism that would use competitively-set fixed amounts for total solar PV production. We believe the SREC approach, like net metering, is unsustainable and results in unnecessary costs to electric customers as a whole.

5. Perspectives on other solar incentive models

Other states have implemented a range of incentive program types in order to grow their solar markets. Several program types that you may be aware of include (but are not limited to):

- ***Standard offer incentive programs (aka. feed-in tariffs)***
- ***Declining block incentive programs***
- ***Competitive procurements (aka. auctions or solicitations)***

There are also many variations on these approaches, as well as co-policies.

Are any of these incentive program types of particular interest to you? Please discuss your impressions of these or other incentive program types that you may be aware of, and whether we should focus on particular incentive types that are of interest to you. How do you think the effectiveness of these incentive program types vary for different solar installation types (e.g. residential vs. utility scale)? What options would you like to see the consulting team consider and analyze for Massachusetts?

We believe the best solar incentive program is one that enables the development of a resource like solar PV at the lowest cost to non-participants, and creates a sustainable solar industry, with low or no subsidies, that can deliver further installations of solar after the 1600 MW goal has been reached. In summary, the use of standard performance-based incentives, publicly set ceiling prices, competitive processes for larger systems, and tariff-based payments all enhance the cost-effectiveness, transparency, simplicity, and risk reduction of a solar support mechanism.

This year, National Grid expects to have the Renewable Energy Growth program (RE Growth) available to Rhode Island customers who are interested in hosting solar PV or other renewable energy resources. This program will include some of the approaches mentioned above, and it will cost all customers nearly half, on a levelized per megawatt-hour basis over 15 years, as much as the combined cost of the Massachusetts net metering and SREC II programs.

The program combines several elements that make it attractive to the Company, participants, and non-participants. First, it is a tariff-based program, in that all of the payments for solar output will be secured and governed by a public utilities commission-approved tariff, and it does not involve contracts, market transactions, or auctions. For small and medium sized solar PV facilities, up to 250 kW in DC nameplate capacity, there will be a fixed price tariff, or Standard Performance Based Incentive (PBI), that varies by system size and ownership.

In exchange for all energy, capacity and RECs, non-residential customers will receive a fixed payment per kWh generated for 20 years (as proposed). Residential customers will receive bill credits for energy (up to their monthly usage) and sell their RECs for the remainder of the PBI amount. The Standard PBI prices are established annually through a public process run by the Rhode Island Distributed Generation Board that must take account of estimated system costs, a reasonable rate of return, and the results of competitive solicitations for such support by larger system owners. This mechanism is simple and low risk, and provides transparency to all customers about how much is being paid for solar output.

National Grid believes the use of the Standard PBI for smaller systems is appropriate along with the regular and public review of the price being paid, with approval from the state's utility regulators.

Solar systems greater than 250 kW, along with other renewable resources, must submit bids in response to competitive solicitations, which are capped by a ceiling price that is established every year by the same RI Distributed Generation Board. Projects will be selected on the basis of price until each enrollment is full, thereby enabling all customers to pay the lowest overall cost for the renewable energy resources. Pursuant to a tariff, the projects receive payments for their output as bid.

National Grid and stakeholders developed this program based on our experience with the Distributed Generation Standard Contract (DGSC) program, which had a 40 MW goal for renewable resources and procured 37 MW. The last procurement of the DGSC enrolled solar PV systems ranging from 173 kW up to 1.25 MW. The total costs for the output from this program, which involved 15-year contracts, ranged from $150 to $240 per MWH, with most systems receiving an average of approximately $200 per MWH. This is approximately half of what similar sized systems will receive, on average, over a similar period in Massachusetts, on a levelized basis.

New York has also used a competitive process that combines upfront grant and short-term performance incentives to solar PV projects greater than 200 kW in size. Under the program, winning proposals received more than $1100 per kW at first in 2011, declining to an average of $439 per kW in the most recent solicitation. An award of $439 per kW is worth an equivalent of $58 per MWH over a period of 10 years, assuming a 10% discount rate. However, this subsidy is provided independently of any revenue captured through net metering, direct on-site usage, or the sale of energy to the NYISO. For this reason, the program does not protect all of the customers who will fund it from any increase in energy and net metering costs, and it continues relying upon the cross-subsidies embedded in net metering, as described in the response to Question 3.

New York is currently in transition to a "declining block" program for solar PV (an approach that was outlined in Massachusetts bill H.4185). A declining block program sets an initial level of subsidy support based on some analysis of the current costs and returns needed to develop a facility. As a "block" or measured amount of capacity is enrolled, the value for the next block steps down to a lower value. Thus, the initial block might receive a total of $250 per MWh, and the second block may receive $230 per MWh. The block values would decline to some predetermined end-point when the program is fully enrolled. While simple and predictable, this mechanism is less cost-effective than a competitive model, and is also insensitive to declines or increases in costs. The support offered by such a program does not take into account the varied development costs and return expectations of different facilities and owners, which can better be met through a competitively set tariff. It does, however, provide open access to the support mechanism and a known cost to all customers, thereby enhancing its transparency. But given the enormous burden created by the SREC program, National Grid would strongly favor a competitive program over a declining block design.

6. Perspectives on future use of net metering, as well as minimum bill provisions

During the past year, efforts have been made to revise the framework for net metering in Massachusetts including the addition of a minimum bill for all electricity ratepayers. Please discuss your perspective on the future use of net metering/virtual in Massachusetts and, to the extent you are able, what options or changes would you like to see and why?

Net metering will not provide a sustainable future or enable the healthy growth of renewable energy generation because net metering customers are avoiding their fair share of system costs, and the costs for non-participants will continue to rise, creating a further demand for net metering as a way to avoid high costs. Taken to its logical conclusion, there would be no one left to provide the subsidies everyone would be receiving. In the long term, this will lead to stranded costs and financial instability for distribution utilities. Only a financially sound distribution company can integrate large amounts of distributed generation. Once interconnected, the distribution company must accept generation from the customer, manage the voltage requirements of the generating facility, manage the voltage levels and frequency levels required for a stable grid, serve instantaneous demand whenever the customer's load exceeds his or her generating capability, and serve the customer whenever his or her generating facility is not producing electricity. According to the Electric Power Research Institute, in order to accomplish all of these tasks independently of the grid, a customer would need to invest between four and eight times more money into their system.[1]

Also, net metering does not send appropriate price signals for customers to consider different operating criteria that may improve the efficiency of the overall electric grid. Under net metering, customers maximize their financial benefit by producing as many kilowatt-hours as possible. Usually, this would promote an installation that faces directly south for solar PV systems, which produce peak output earlier than at the typical system-wide or feeder level peak demand. At present, net metering does not incorporate price signals to promote more efficient behavior or alternatively, provide a credit for services to the utility. National Grid recommends that net metering, or its successor design, should be crafted so as to reward solar PV generating customers to install advanced inverter technology or turn their system to the west to help meet system peak load needs, as services to the utility, and not reward those system owners who choose not to provide those services.

Virtual net metering only amplifies the cost recovery problem. A solar developer can allocate kWh to an account far away without paying any delivery charges. At the same time, the customer who receives the kWh value receives a lower bill. However, neither party is paying an appropriate share of the fixed costs of the distribution system. Virtual net metering can only happen with connection to the grid. For that reason, both the generating customer and receiving customers should be paying a fair share of the costs to create an integrated grid.

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1 Electric Power Research institute, "The Integrated Grid: 2014, p. 7, and pp 16-23 along with Appendix A for discussion of services and cost estimates.

In the long term, National Grid believes these inequities should be solved with a rate design that derives from a several basic concepts:

1) Customers using energy and distribution system services should pay for those services in a fair manner, including coverage of the fixed costs of the T&D system;
2) Customers with generation should be able to use their generation on-site, and should be compensated for generation put on the grid in a fair manner, as well as pay for access to the grid with coverage of an equitable share of the fixed costs of the T&D system;
3) Customers that provide services to the grid should be compensated for them; and
4) Additional incentives the Commonwealth would like to provide to a technology, like SRECs, should provide all other remuneration and should be equitably funded by all electricity customers in the state who can receive them.
5) Such rates should be set through proceedings at the Department of Public Utilities.

As a first step toward that model, National Grid believes a minimum bill will allow for more appropriate cost recovery from all customers. Minimum bills should be designed to recover distribution costs of service based upon causation, i.e. size of customer and diversity of customers contributing to the calculation of the minimum bill. Also, minimum bills could be designed to recover non-distribution costs that are impacted by reductions in kWh deliveries such as costs for systems benefits (energy efficiency programs, renewable programs, low income credits, etc.).

The minimum bill should be based upon the size of the customer since the system is designed to serve their maximum loads. Small customers with lesser need for the system should not pay the same amount for a minimum bill as much larger customers. (This approach is standard for demand-based rates where the rate per demand is the same but the amount of a customer's bill is dependent on the size of its demand.) For smaller customer sizes, minimum bills could be based on service connection level, total monthly usage (inflow or outflow of kWh), or an actual measure of peak use with eventual deployment of Advanced Meter Functionality. For larger customers, the tools are already in place to measure peak kW and kVA, and minimum bills can be designed to reflect the maximum export or import by the customer at its location.

This approach would have other beneficial effects, beyond more equitable cost allocation. Customers will be incented to save by managing their maximum demand on the grid, which may reduce growth related distribution upgrade costs, transmission capacity costs, and regional increases in generation capacity needs. This could be accomplished by lowering on-site peak demand and/or managing generation capability to ensure output is available at peak demand times. This design would also provide an appropriate charge to customers that are primarily generators that transmit their output onto the distribution system and sell energy to other customers at remote locations, as most VNM customer hosts are doing today.

Finally, the design could allow for minimum bills to be reduced through the provision of measurable services to the distribution company at prices that reflect the value of the services to the distribution grid. Such services might include peak reduction in an area with identified constraints and/or voltage optimization at the feeder level.

The specifics of the minimum bill, as with all rate design, would be determined in the context of a distribution company's rate case before the Department of Public Utilities.

7. Perspectives on policy transitions

A. At the 2nd Task Force meeting, it was suggested that analysis should account for uncertainty costs, (i.e., transition costs due to changing goals and programs.) Please discuss qualitatively the nature of these costs as you see them, and whether and how you might suggest such costs could or should be quantified.

National Grid is uncertain regarding the meaning of this question. Every stakeholder faces uncertainty in regular times and during transitions. For example, a transition from net metering to another form of compensation for customer generation will create uncertainty for the generating customer but create benefits for other customers in the form of reduced costs from an improvement in the equity of cost recovery among customers for distribution services. Thus, any uncertainty in costs by one stakeholder will result in opposite benefits for other customers. These uncertainties cannot be considered simply a cost but the result of improving the fairness and equity of cost recovery as well as helping to lower overall costs to customers.

The appropriate means to deal with uncertainty is to create as much certainty as possible regarding a transition. Important elements such as start date, end date, length of transition, goal of the transition, major milestones and approval dates will help everyone adjust to the purpose of the transition and prepare for the changes ahead. Uncertainty is created when goals, purpose and timeline are not clear or are subject to extension, modification or delay. Once these are made clear, uncertainty costs can be minimized or avoided as stakeholders adapt to the schedule, purpose and goal of the transition.

B. Are there particular threshold milestones where it might make sense to consider policy transitions in order to minimize such costs? What other means are available to minimize such costs?

Every effort should be made to minimize costs to utility customers. Transitions should be designed to accomplish their benefit for customers quickly and milestones should be selected in accordance with the goal. Competitive acquisition of resources necessary to implement policy is one means to minimize transition costs since, by definition, the bidders have provided their best price for the service. Transitions defined by competitive solicitation will minimize any perceived transition costs by stakeholders while providing maximum benefits for customers.

8. Sector-specific topics

1. Group A: Utilities

How would you propose a minimum bill calculation methodology be applied? What other models would you point to that are viable for achieving your objectives?

As discussed in the answer to Question 6 above, all customers, both load and generation, should be charged a minimum bill based upon size as measured in demand/maximum output capability or energy use/energy produced. The minimum bill calculation should be applied according to a customer's size as measured by their actual maximum demands or by alternatives to measuring demand when demand meters are not available. Alternatives to measuring demand include customer charges based upon a range of kWh use or the service size of a customer's home or business, if available. Using measures of demand in kW or kWh ranges encourages customers to manage their use to improve system efficiency and lower their costs as well as costs on the grid. Customers would also still have the incentive to consider energy efficiency measures that not only save energy but save on maximum demand to effect an improvement in the capacity utilization of the grid. Improved utilization of the grid will lessen the need for future investment and lower the average cost to customers as utilization increases.

Other models include raising the customer charge. This option has been proposed and approved in a number of jurisdictions as a simpler means to put in place a minimum bill structure. One drawback to the approach is the disconnection from improving customer efficiency and system efficiency as more costs are moved to a charge that does not have any variation. Another drawback is the disproportionate effect on smaller customers from increases in the customer charge. Finally, this approach may take longer to effect a transition since bill impacts to all customers must be considered and a one size fits all customer charge will take longer to finalize to a point in which it recovers the amount of non-bypassable costs necessary to run a distribution grid.

The best design in the end would be one where all customers accessing and using services from the grid pay an appropriate share of fixed costs of the grid, and those providing grid services are compensated for them. This is a step beyond net metering, towards a more realistic assessment of cost responsibility and value of services provided.

With respect to FCM revenues for current Class II and III systems, for which utilities secure certain rights under net metering tariffs, please describe your current practices, and future plans.

The enrollment of solar PV capacity from net metering systems is currently under consideration by National Grid.

Are utility system integration costs for solar projects now fully borne by project owners?

Costs to interconnect a project with the distribution system are borne by interconnecting customers. However, there are operating and maintenance (O&M) expenses of new infrastructure that are not included in rates or borne by the customer. Under the current interconnection tariff, on-going O&M costs are not being collected from the DG customers when they pay for a system upgrade to allow their project to interconnect with the electric system. With an approximate 6% annual O&M cost, every dollar paid for an upgrade results in 6¢ of on-going annual O&M costs (maintaining the equipment, tree trimming, local property taxes, etc.). In 2013, the Company built approximately $15 million in interconnection upgrades (primarily in rural areas with minimal existing electric load), which results in on-going annual O&M expenses of approximately $900,000 that are not being collected from the interconnecting customers and are not reflected in base rates.

Residential customers are rarely charged any money to interconnect, and the Company has installed over 8,000 residential class net meters over the past four years. At approximately $75 per meter, this is an additional $600,000 of capital investment that will not be included in rates until the next general rate case. The current rate of residential solar installations is about 7,500 per year, so the Company expects an additional $560,000 per year of such investment, along with the associated annual O&M costs as described above.

What are the expected potential impacts of Grid Modernization/Time-Varying Rates efforts on net metering value and framework?

In the recent docket on Time Varying Rates, the Department determined that TVRs were appropriate for charging the costs of Basic Service. However, the Department accepted the argument that the costs for distribution service would be recovered through different means, not necessarily TVRs. If in service, customers could receive the value of the time varying rates when their generation is running. However, there are many issues with this approach that have not been examined, all relating to reconciliation of costs and cost incurrence in the ISO-NE market. National Grid is using its Smart Grid Solutions pilot in Worcester to examine these issues as some pilot customers do have solar generation behind the meter. The introduction of TVRs at the retail level that differ from the prices charged in the wholesale market introduces risks to cost recovery and efficiency that must be understood before any impact can be estimated. Thus, the potential impacts are unknown at this time.

Grid modernization can have a tremendous impact on customer investment in distributed generation, particularly when costs are recovered appropriately through minimum bill provisions. Grid modernization investments can prepare the grid for widespread use of distributed generation by creating the means to integrate the generation into the distribution grid. However, this can only happen with appropriate pricing for distribution services that appropriately funds those investments that prepare the grid for DG by charging generating customers appropriately for costs incurred.

What are your experiences in other state solar markets with alternative incentive models or policies in place?

Please see the answer to Question 5 above.

Please describe your past and expected future participation in SREC floor price auctions.

National Grid has not participated in any of the SREC auctions, but this is open to review and determination as each auction arises. National Grid has not participated because (1) the Company has generally been in the marketplace for SRECs prior to and during the auction and has typically secured sufficient SRECs at a cost lower than the auction floor price of $300 to match with its compliance obligation, and (2) purchasing SRECs in the auction would be speculative if meant to be used for load that is not near term (from the current year to 18 months in the future), and would require the company to fund the purchase well before such costs could be collected in commodity rates. However, if the Company needed SRECs for the current year at the time of the auction, and market prices were above the auction floor price, then the Company would consider participating in the auction in order to reduce overall RPS costs for customers.

What information can you make available to the consulting team to help us assess the role of avoided T&D cost (if/where applicable) and avoided distribution losses resulting from installation of distributed solar generation?

The Company is comfortable with using the 2007 Navigant study as a starting point. This study focused on specific deferral opportunities after it was determined that a generic system-wide approach, as is used in the Avoided Energy Supply Cost studies, conducted to help calculate benefits from the energy efficiency (EE) savings, was not feasible since at the time the diversity of DG was not in place. In addition, EE removes kWs from the system for the life of the installed measure in a passive manner, whereas DG is subject to weather related issues as well as unplanned outages, and other events. As the bulk of the 310 MWs of solar PV connected to the Company's system are 750 kW to 6 MW solar farms, the diversity if DG is still not in place. Understanding that the typical 15 kV distribution feeder can serve up to 8-10 MWs, a DG project that is a large percentage of this load becomes a contingency that the Company's engineering staffs have to plan around to maintain reliability to the other 2,500 to 4,000 customers served off the feeder.

Specific deferral locations should follow the Company's current internal guidelines for non-wires alternatives (NWA). These include:

1) The standard wires solution will likely be more than $1m – this is to provide enough deferral value to pay for a NWA;
2) The load reduction should be less than 20% of the peak load – this is to put bounds around the size of the NWA as the funding is limited by Guideline 1 above;
3) Start of construction is at least 36 months way – this is to provide enough time for customer outreach, marketing, enrollment, and construction of the NWA; and

4) The need is not based on asset or reliability condition – this is critically important as only truly growth related projects (location where the equipment is in excellent working order, but the load growth in the area has out-stripped it's capacity) is where deferral is feasible.

The use of the Navigant study can provide an approach to estimate specific locational benefit values for solar PV projects. In addition, the output of the Company's Phase II solar project is designed to value the specific benefits around true localized peak load relief (by re-orienting PV panels), the use of advanced inverters to provide voltage support (through the absorption or injection of VARs), and ride through capabilities (to provide bulk power system stability). The output of this study is specifically designed to answer many of the questions around the true benefits of distributed solar projects.

9. Other topics

Are there any major topics or perspectives related to the Task Force's scope that we have not discussed today that you would like to comment on?

A) Consumer Protection and Competitive Supply Issues with Third-party Ownership Structures

National Grid believes that due to the quantity of and desire for customer-hosted solar projects that are owned by third parties, which often involve electricity contracts, net metering contracts, and leases of real property, greater transparency about the true value provided to customers is needed. In addition, this market should be better integrated with competitive energy suppliers and the competitive retail supply market.

Because more than half of the net metering cap is reserved for net metering projects hosted by municipalities and other governmental entities, all contracts between solar developers and public entities, and the terms of those contracts (deposits, escalation factors, purchase rights and values, and other elements), should be publicly reviewed as part of this effort. This review will give the task force valuable information about the benefits that our municipalities and governmental entities are receiving from their solar installations versus what the developers are receiving, which is vital to know in order to assess how we can achieve our solar goals more cost effectively. Pursuant to G.L. c. 30B, § 1 (b)(33), energy contracts for energy or energy related services entered into by cities, towns, or political subdivisions of the Commonwealth are exempt from the typical requirements of the Massachusetts uniform procurement act, which may extend to net metering related contracts. However, such exempt contracts are required to be filed with the Department of Public Utilities, the Department of Energy Resources, and the Inspector General's office, which should provide an opportunity for public review of the contracts.

In addition, a 2012 session law expanded G.L. c. 164, s. 137, "Participation in group purchasing of electricity," among other things, to relieve municipalities and state agencies from competitive bidding requirements in granting easements, licenses, leases, etc. on real property, and to allow state entities, including the legislature, to dispose of municipal or state property by lease, easement or license when a renewable energy PPA or a net metering agreement and a group purchase is involved. Similarly, because residential net metering facilities are not subject to a cap, and virtually all such facilities are third-party owned, standard residential solar net metering contracts should be developed, regulated, and closely reviewed by state energy and consumer protection offices. In addition, solar development companies offering these solar net metering contracts to residents, business, and public entities of Massachusetts should be regulated by the Department of Public Utilities as competitive energy suppliers, and properly licensed as such.

B) Clarify Total Cost, Savings and Payments Under Current MA Policies

We believe the consultant report to the Task Force must clearly lay out the source and reality of the "bill savings" for customers that purchase net metering credits, along with the total costs and payments involved in net metering. Furthermore, the split of total payments for solar between developers and credit purchasers should be clearly explained, along with estimates of what developers need at present to develop new solar installations.

This breakdown is important because, while the total amount paid for such credits by such a customer under a PPA with a solar developer may be lower than standard rates, this cost reduction may not be guaranteed, and may not be long lasting. In addition, one customer's "savings" is an added cost for all other customers.

For example, assume each kilowatt-hour produced by a solar PV array is worth 18¢ per kWh in net metering credits, plus 30¢ per kWh in SREC II value, and that the developer signs a long-term agreement to sell the net metering credits to a town for 13¢ cents per kWh. The 18¢ per kWh in net metering credits is then applied to the town's electricity bill and the town will realize savings equal to 5¢ cents for each kWh that it purchases. Meanwhile, the project developer realizes 43¢ per kWh. However, if the project only needed 30¢ per kWh to be built and provide an acceptable return, it will realize 13¢ per kWh of additional profit. Also, the town is receiving 5¢ per kWh of "savings" from net metering, but other customers are now paying for its share of the distribution system's fixed costs. The total cost to all customers is still 48¢ per kWh, less the value of wholesale energy and any delivered energy losses.

In short, the Task Force should be provided a clear picture of the total payments by all customers for solar output, the value of bill reduction that credit purchasing customers are receiving, and the average revenue needs solar developers need today to create new solar PV facilities given current installed costs, financial structures, and return expectations.

NCLC comments re: Net Metering Task Force, consumer group discussion

Jan. 20, 2015

1. Stakeholder objectives: In discussions about net metering -- and more broadly, distributed generation and grid modernization – affordability and equity policy objectives must be valued as highly as those associated with environmental policy. Rate design, any grid modernization investment, and DG programs and policies must mitigate pre-existing regressivity in the allocation of costs and benefits of energy resource production, distribution and consumption. NCLC wants to make sure that in exchange for any costs imposed on ratepayers by net metering (see GL ch. 164, s. 139, under which ratepayers directly bear the "distribution portion of any . . . net metering credits"), those ratepayers receive equivalent or greater benefits. While I know that the terminology has become somewhat loaded, NCLC wants the process to produce some quantification of the value of the kWh that net metered customers deliver to the grid, including (to be fair to those net metered customers) the value of: avoided costs of otherwise generating the kWh; any avoided transmission or distribution investments; contributions at times of system peak; deferral or avoidance of investments in new generation plants or gas pipelines to feed those plants; and other reasonably quantifiable benefits.

We also want the Task Force process to make transparent any subsidies/supports/payments to net metered customers.

Finally, we want to make sure low-income households are able to participate as direct players in solar PV and other projects that benefit from net metering, whether through community shared solar or other means.

3. Perspectives on current net metering approach: In the absence of quantifying the value of kWh delivered under the current net metering laws and structures (see #1 above), our perspective is that net metering may pay net metered customers more than the value of the kWh delivered; but that is of course an open question. Put another way, it would be remarkably fortuitous if the value of the kWh delivered under net metering happened to be equal to the (more or less) retail price of electricity, rather than having a greater or smaller value. It is possible that the arguments for volumetric caps would be greatly diminished if some consensus could be reached about the value of kWh delivered via net metering, and the payments to those customers were commensurate with the value delivered. Caps may be an artifact of concerns, particularly on the part of utilities, that net metering unduly erodes revenues without providing sufficient system benefits.

6. Future use of net metering/minimum bill provisions: As should be clear from the above, we question the wisdom of continuing the current net metering structure in the absence of analysis showing that the value of kWh delivered via net metering is at least equal to the payments made to the net metered customer, given the provisions of GL 164 s. 139(c).

As for "minimum bills", those words can mean many things. If interpreted to mean an unavoidable customer charge imposed on all customers, and at levels much above current customer charges, we are strongly opposed to minimum bills as so defined. Because higher customer charges lead to lower kWh charges (under any fixed revenue requirement), customer charges fall most heavily on lower-consumption customers. Analysis done by my colleague John Howat shows that there is a strong correlation between low-consumption customers and low-income households, as well as African-American, Hispanic, and other minority households. Further, because higher customer charges result in lower kWh charges, this provides much less of an incentive to invest in energy efficiency or self-generation, as the cost of the avoided kWh is lower.

To the extent minimum bills would apply, in practice, mostly to customers who self-generate and therefore have unusually small bills (say, 100 kWh or less), we are neither opposed nor supportive at the present time.

8. Sector specific questions:
We are concerned that low-income households face significant hurdles in trying to participate in net metering (or other models that may result from the task Force process). Solar PV and other technologies that allow a customer to engage in net metering generally require significant up-front investment, or, if a third-party vendor is involved, a strong credit score. We would want to ensure that any policies going forward give low-income households and communities a fair chance to participate. In particular, this may require consideration of incentives and models that work for community shared solar. As is apparent

from the above, we also want there to be a clear demonstration that incentives provided via net metering (or subsequent policies) result in ratepayers as a whole getting equivalent or greater value from the kWh delivered to the grid.

As to grid modernization and TVR, NCLC has consistently raised the concern that a strong business case needs to be made before potentially massive investments are made to modernize the grid. Similar to our concerns about net metering as currently structured, we haven't seen evidence that the investments in grid mod that are being considered would yield substantial enough merits to justify the costs. We also are concerned that mandatory TVR could adversely affect low-income households, who tend to have fewer appliances and loads that can easily be shifted off of peak periods. We realize that your question asks about the potential effect of grid mod and TVR "on net metering value and framework"; we have no opinions to offer on that right now but do want to voice our general concerns about grid mod and TVR.

Submitted by Charlie Harak

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January 21, 2015

RE: Massachusetts Net Metering Task Force
Phone Focus Group F – Written Supplement

Dear Mr. Belden, Ms. Wright, and Mr. Grace,

Thank you for the opportunity to participate in Thursday's call regarding the Massachusetts Net Metering Task Force. We appreciate the opportunity to follow up on this call by providing additional comments. SRECTrade is one of the largest SREC transaction and management firms in the industry, with over 145 MW of solar assets under management.

Introduction to SRECTrade

SRECTrade facilitates the brokerage of spot and forward contract SREC transactions in the over-the-counter markets. SRECTrade's clients cover all market participants including, competitive electricity suppliers, utilities, project developers, PPA providers, leasing companies, installation firms, and individual commercial and residential system owners.

The software developed by SRECTrade allows solar owners to track their SREC generation and issuance, manage and execute transactions, and enroll facilities with state regulators. Since 2008, SRECTrade has been one of the leading sources for information regarding SREC price trends and legislative updates, bringing a wealth of knowledge and transparency to some of the fastest growing state markets in the solar industry.

We have been an active participant in the Massachusetts solar industry since the inception of the SREC program in 2010. SRECTrade was the first aggregator to register and transact SRECs from the first facilities to qualify for the SREC-I program. We facilitate transaction and management services for more than 4,100 facilities in the Commonwealth, representing more than 60 MW.

SRECTrade represents a significant and diverse group of Massachusetts businesses, residents, and investors. We have seen firsthand the value and shortcomings of the Massachusetts SREC programs that may be missed by other groups that solely focus on the sale and development of solar facilities. Our experience in the market has equipped us to be able to provide unique insight into the efficacy of aspects of the existing solar incentive program structure. Additionally, our relationship with our clients ensures that we have a long-term commitment to the owners of solar arrays because qualified facilities produce SRECs for ten years from the time that they become operational. We have made it a priority to engage our customers with a transparent platform, creating an environment where the residents of the Commonwealth can feel involved and knowledgeable about the SREC market and the return on their investment in solar. We stand alongside many residents of the Commonwealth, sharing a common desire and eagerness to help Massachusetts achieve its full potential with renewable energy.

Interrogatories & Comments

1. Stakeholder Objectives and Priorities from the Task Force Process

Over the past four and a half years, Massachusetts has seen immense success and impressive growth in the deployment of Solar PV. This growth is a testament to the Commonwealth's RPS program and successful incentive programs, including SREC I and SREC II, The Green Communities Act, and other incentive and rebate programs. Unlike other efforts for alternative energy integration, such as the controversial, and now stalled, Cape Wind project, the policies supporting the solar market have proven to be seamless and productive—meeting and exceeding program targets and goals. Massachusetts' solar policies set the stage for Massachusetts to become the national leader in solar that it is today, but it is vital that Massachusetts continue to promote and implement solar policies that bolster the Commonwealth's renewable energy future. Accordingly, we would encourage the Task Force to focus on improving existing policies, rather than disrupting the market with an abrupt policy change.

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2. Long-term Massachusetts Solar Market Goals

In an effort to maximize the benefits of solar while minimizing costs, we encourage the Task Force to focus on the following goals:

1. **Maintain the SREC II Program.** The Massachusetts SREC I and SREC II programs have proven that market participants have been able to thrive under the existing framework, and the industry has built a successful infrastructure to continue to leverage more growth. The programs were carefully designed to minimize costs while maximizing growth, job creation, and market stability. A shift in policy away from the SREC incentive would create instability and invite uncertainty in the market, triggering a disruption in the market. In the interest of encouraging continued growth, we believe it is in the best interest of the Commonwealth to work to improve, rather than to replace, the successful SREC program.

2. **Lift the net metering caps.** Net metering caps have proven to be relatively unproductive policy mandates—constantly requiring review and reconsideration by the Legislature, when resources could be better spent focusing on improving the existing program. With forecasts projecting that the existing net metering caps will be reached within the first half of 2015, it is of paramount importance that the Task Force encourages the lifting of the net metering caps. Eliminating this barrier will allow Massachusetts to continue on its path of booming solar success.

3. **Prioritize distributed generation to increase grid reliability and resiliency.** Equitable access to solar will maximize growth and provide the best opportunity for the Commonwealth to increase grid reliability and resiliency. Accordingly, we encourage the Net Metering Task Force to carefully consider opportunities to expand access to solar to those limited to the use of virtual net metering and to those in low-income communities. This goal would include taking into consideration the preservation of virtual net metering for community solar projects, the establishment of financing programs for low-income communities, and the overall rate redesign for Massachusetts ratepayers. By focusing on these issues, Massachusetts can maximize its growth potential and continue to add reliability and resiliency to its grid.

3. Perspectives on Current Net Metering Approach

Please see the response to Question 2, Point 2.

4. Perspectives on Current Massachusetts Solar Incentive Model Approach

With respect to its incentive structure, the Commonwealth of Massachusetts is in a unique position because it can utilize its deregulated electricity supply structure to continue to foster a competitive market for both traditional and renewable electricity. Continued use of the existing REC and SREC markets is the clear path to fostering the most competitive market for all stakeholders in the incentive program. This includes solar developers and system owners, competitive electricity suppliers, and the Massachusetts ratepayer. The market minimizes costs while maximizing growth, job creation, and market stability.

In less than four and a half years, the Solar Carve-Out Program (SREC I) helped to incentivize the development of 654.7 MW of qualified capacity across 11,787 qualified projects (as of 1/12/2015).[1] In 2013, Massachusetts was ranked 4th in annual installed solar capacity (237 MW installed in 2013) and 5th in cumulative installed capacity (678 MW cumulative).[2] The 2014 Massachusetts Clean Energy Industry Report states that "Solar Deployment is Creating Thousands of New Jobs in Massachusetts, Half of All Renewable Energy Jobs Statewide," with nearly 60% of the state's 21,000 renewable energy jobs related to the solar industry.[3] And according to a recent report titled, "A Survey of State-Level Cost and Benefit Estimates of Renewable Portfolio Standards," issued by the National

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[1] *See* RPS Solar Carve-Out Qualified Renewable Generation Units, available at http://www.mass.gov/eea/energy-utilities-clean-tech/renewable-energy/solar/rps-solar-carve-out/current-status-of-the-rps-solar-carve-out-program.html.
[2] *See* http://www.seia.org/state-solar-policy/massachusetts.
[3] *See* http://images.masscec.com/reports/Executive%20Summary.pdf.

Renewable Energy Laboratory (NREL) and the Lawrence Berkeley National Laboratory, compliance costs for the state of Massachusetts in 2012 equaled $111 million compared to benefits of $328 million, representing a net benefit of $217 million under the current Renewable Portfolio Standard incentive program.[4]

In addition to its economic successes, the SREC program offers inherent ratepayer protection with its flexible incentive pricing. SREC prices adapt as supply, demand and market dynamics shift. Furthermore, the SREC II program introduced even more flexibility to the program by requiring the Department of Energy Resources (DOER) to review the SREC II Factor Guideline by March 31, 2016. This review will allow the DOER to reduce the SREC II Factors to lower the overall costs of the program to ratepayers if market conditions permit it.[5] Finally, the design of the program allows a facility to revert to producing Class 1 RECs after its forty quarters/ten years of eligibility in producing SRECs under SREC I and SREC II have expired. This creates continuity and predictability in the market that would not be available, for example, with a declining block incentive model. Carefully contemplated and calculated programs like SREC II also create confidence in the marketplace, which is a fundamental element in ratepayer protection, and one that should not be overlooked. The current successes were achieved over the course of several years of stakeholder time, capital, and intellectual effort, and the flexible yet reliable market should continue to be employed by the Commonwealth.

Understandably, as with any market, there are always areas to fine-tune. In its task to review the current incentive program, we would encourage the Task Force to consider the following topics to improve upon an already-successful program:

- Improving SREC market liquidity and long-term contract opportunities;
- Minimizing costs to ratepayers through stable pricing, while providing the appropriate level of incentive to solar project owners;
- Increasing market transparency with clearly published supply and demand information, as well as pricing data; and
- Encouraging competition among electricity suppliers, not only to facilitate cost-reduction pressure, but to make the market as open and accessible as possible.

Given our experience in the market, we welcome the opportunity to discuss these topics with the Task Force further, and are happy to answer any questions that the Task Force may have for us.

5. Perspectives on Other Solar Incentive Models

SRECTrade is an active participant in all SREC markets. Additionally, SRECTrade administered the competitive procurement process for SREC Delaware ("SRECDE") for two years, an experience which presented its own shortfalls and administrative costs. For competitive procurements in particular, the administrative cost is high and the incentive for improvement is low. Competitive procurements present their own legal, administrative, and soft costs, and include an added upfront burden of soliciting and selecting a program administrator. A central aspect of competitive procurement programs like SRECDE is the lack of natural competition. In administratively run and controlled programs, there is no competition-driven incentive for improvement; in contrast, there is natural competition in market-based mechanism such as the Massachusetts SREC program, which encourages stakeholders to improve services in an effort to capture greater market shares.

While many other incentive programs exist, it is important to give gravity to the program that has proven to be extremely successful in Massachusetts—the SREC program. The success of the program is supported by increased solar installations at a lower price per watt,[6] growth in the renewable energy job industry,[7] and a program that can

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[4] *See* http://www.nrel.gov/docs/fy14osti/61042.pdf.
[5] *See* 225 C.M.R. 14.05(9)(I)(3).
[6] *See* http://www.mass.gov/eea/docs/doer/renewables/installed-solar.pdf; *See also*, U.S. Solar Market Insight: 2010 Year-In-Review, Full Report, SEIA and GTM Research, 2010.
[7] 2014 Clean Energy Industry Report: Executive Summary, *available at* http://images.masscec.com/reports/Executive%20Summary.pdf; 2013 Clean Energy Industry Report, *available at* http://www.masscec.com/content/2013-clean-energy-industry-report; 2012 Clean Energy Industry

adjust to changing supply and demand dynamics by taking into consideration installation costs, electricity rates, and other available incentives.[8]

6. Perspectives on Future Use of Net Metering, as well as Minimum Bill Provisions

As previously discussed, we encourage the Net Metering Task Force to carefully consider opportunities to expand access to solar to those limited to the use of virtual net metering and to those in low-income communities. Virtual net metering presents a variety of problems in capacity markets and with kilowatt restrictions in incentive programs, and these limitations must be addressed. To address these issues, we would encourage the Task Force to look to other markets that have been successful in using net metering and decoupling to its ratepayers' and regulated utilities' benefits.

When taking into consideration whether a minimum bill should be part of overall rate redesign, it is critical that the Net Metering Task Force weigh the benefits that distributed generation facilities are providing to the grid, including grid reliability, resiliency, and reduced demand during peak periods.

7. Perspectives on Policy Transitions

Instability and insecurity are the hallmarks of failed incentive programs. States that are constantly shifting gears and making drastic policy transitions create uncertainty in the market, which can result in unintended consequences such as increases in financing costs. This can result in fewer projects being financed and ultimately a decline in renewable energy jobs and industry growth.

On the other hand, improving existing programs promotes stability and confidence in the market, encouraging investment by stakeholders across the industry. Of the two paths, the choice seems clear: to follow the path that will continue to make Massachusetts a leader in solar.

Thank you for your consideration in this matter.

Best Regards,

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Report, *available at* http://www.masscec.com/content/2012-clean-energy-industry-report; and 2011 Clean Energy Industry Report, *available at* http://www.masscec.com/content/2011-massachusetts-clean-energy-industry-report.

[8] See, et al., Figure 2-16: Massachusetts PV Installations and SREC Prices, 2010-2011, U.S. Solar Market Insight: 2011 Year-In-Review, Full Report, SEIA and GTM Research, 2011.

Net Metering Task Force - Focus Group Interview
Northeast Utilities Answers
January 23, 2015

1. *What are your goals and objectives for the task force? Of those, what is your most important objective and why? To the extent that goals or objectives may conflict, how would you prioritize?*

NU supports MA clean energy goals and is committed to help the State meet those goals. However NU is concerned about the costs associated with reaching these goals, specifically the solar goal. NU believes that MA should focus not only on a volumetric goal (i.e., 1,600 MW), but it should also develop a cost-effectiveness goal (i.e., all-in cost per kwh of solar installed) in order to ensure that the volumetric goal is accomplished without the use of significant level of incentives. In order to move forward, the State should learn from other jurisdictions that have been able to increase the share of renewables and solar, but in a much more cost-effective manner.

MA's incentive structure for solar relies on two mechanisms that need to be reexamined and adjusted in order to meet NU's proposed cost-effectiveness goal: 1) net metering credits and 2) Solar Renewable Energy Credits (SRECs). These financial incentives are paid for by all customers, regardless of whether their homes or businesses are interconnected to solar distributed generation facilities.

Similar billion dollar investments in clean energy could reap more benefits if done in a balanced and strategic way. NU believes a more balanced approach is needed to meet the state's solar goals to ensure that 1) MA's customers are not paying above-market prices for energy; 2) there is rate fairness among customer groups and 3) there is transparency in the level of incentives provided to solar or any other renewable resource.

2. *The current stated goal of the Massachusetts solar policies is to reach 1,600 MW of installed solar capacity in the 2020 timeframe. Please discuss your perspective on this MW goal, its timing, and the appropriate objectives for the state solar market beyond the timing and quantity of this goal.*

NU's analysis indicates that Massachusetts is currently investing in solar power at well above market prices. Solar power with MA's incentives has been priced 6-8 times higher than conventional wholesale power and 3-5 times more than conventional wholesale renewable power over the past several years (see table below). MA's solar incentives are 3 times as high as those provided in CT through a competitive program. Given current trajectory, over the next 15 years MA customers will pay a projected $7 billion in above market costs just for solar power. NU contends that the State needs to analyze whether this level of investment is warranted and believes there are better mechanisms to achieve similar solar goals, at a much lower cost.

Net Metering Task Force - Focus Group Interview
Northeast Utilities Answers
January 23, 2015

Illustrative MA Solar Net Metering Costs (c/kWh)						
	2010	**2011**	**2012**	**2013**	**2014**	**2015**
Net Metering Rate Components						
Energy	8.4	7.5	7.3	7.3	9.4	10.9
Transmission	2.3	2.3	2.3	2.3	2.3	2.3
Distribution	5.3	5.3	5.3	5.3	5.4	5.5
Total Net Metering Value	*16.1*	*15.2*	*15.0*	*14.9*	*17.1*	*18.8*
Avg. SREC I Market Price	*58.6*	*52.9*	*29.2*	*25.0*	*29.0*	*43.5*
Total Solar Payment	**74.7**	**68.1**	**44.2**	**39.9**	**46.1**	**62.3**
Avg. Wholesale Energy Price	5.0	4.7	3.6	5.6	6.9	7.0
Avg. Class I REC Price	2.5	2.0	5.7	6.5	5.5	5.5

3. *Solar PV systems in Massachusetts typically benefit from net metering with various system sizes and configurations receiving different net metering benefits. Additionally, volumetric caps to net metering have been revised through legislation on multiple occasions over the past several years. Please provide your perspective on the current Massachusetts net metering approach.*

NU believes the existing net metering approach is not well designed to support increased deployment of distributed generation and solar in an efficient, cost effective and sustainable manner. Net metering was put in place many years ago and did not contemplate the level of deployment currently being planned for. Specifically NU wishes to highlight the following:

- T&D services are supported by largely fixed costs driven by customer and maximum demand, and not by energy usage.
- Through net metering, DG customers are avoiding paying for some or all of these T&D services (resiliency, maintenance of grid), yet receiving even more value from the grid (reliability, start-up services, ability to transact and monetize solar energy).
- These costs that DG customers are being credited for, even though they are being incurred to operate and maintain the grid for their use, must still be collected by the electric utility company and are increasing the costs to non-DER customer bills.
- Further, DG customers are avoiding other non-T&D costs and shifting cost recovery to non-DG customer bills. For example:
    - Renewable Fund ($12M total cost for NSTAR and WMECO)
    - C&LM/Energy Efficiency Fund ($234M total cost for NSTAR and WMECO)
    - Reconciling rates for Company and public policy programs (e.g. pension, attorney general consulting, net metering, storm costs, basic service reconciliation, low income and transition ($105M total cost for NSTAR and WMECO)

Furthermore, virtual net metering (VNM) has created a significant cross subsidy mechanism and administrative burden. VNM's specific issues include:

- Transfer of payments from generator to customer accounts has no relation to actual load reductions. It is a pure financial transaction that has no relationship whatsoever with the actual generation and use of energy.
- Host and customer accounts are unrelated resulting in imbalances between credits and customer bills with some customers creating significant credit balances.
- Settlement requirements for net metering customers with DG greater than 60 kW are an administrative burden and results in conflicts with ISO rules
  - State rules require net metering units up to 10 MW to be registered as settlement only generators (SOGs) when ISO-NE does not recognize SOGs at 5 MW and greater
  - DG owners who bid capacity into the FCM market are "double dipping" because capacity payments are part of the basic service price that they receive credit for
  - Utilities should be allowed to treat all net metering resources as load reducers which would eliminate ISO conflicts
- Community solar garden operators are essentially retail energy suppliers that are offering green products to customers, but they are not subject to the same licensing requirements as competitive retail suppliers nor are they purchasing power through the ISO-NE market as do other suppliers.
- Billing is largely manual as costs recovery for implementation has not been granted. In addition manual bills are growing at an unsustainable pace.
- Customers are confused by virtual net metering transfers as they struggle to match credits with host bills.
- Hosts are not billed on the appropriate rates as they take service based on parasitic load rather than capacity of the unit. Larger generators should be assigned large commercial rates; this results in improper cost allocation.

The current net metering approach relies on an artificial construct that does not reflect actual power flows. For customers with bi-directional or interval metering, It involves taking the difference between energy measured on an import channel and an export channel of a customer meter. The effect is to replicate a single register meter that "spins backwards", but this has no logic when generation and delivery is measured on distinct channels.

- When energy is metered on separate channels (as is currently the case for any unit greater than 60 kW), there is no need to subtract channels. The export channel reflects total energy exported after serving load.
- The netting process creates a mismatch between billed retail energy and actual metered wholesale energy for interval metered customers. Net metering customers often times report zero load as a result of the netting procedure when, in fact, they have real load obligations that are picked up by suppliers. These costs are ultimately recovered from all customers through a reconciliation of costs for both Basic Service and alternate supply.

Ultimately as explained further, NU believes the existing net metering and virtual net metering system needs to be replaced with a new rate design that more properly recognizes today's environment and ensures the principle of rate equity.

4. *Massachusetts solar installations typically benefit from a range of incentives, including SRECs, federal tax credits and net metering being major contributors to system economics. Please discuss your perspective on the current mix of incentives other than net metering (and virtual net metering) available to Massachusetts solar systems with a particular focus on the Massachusetts SREC incentive.*

The RPS Class I Solar Carve-Out has been very good at supporting the development of solar resources, but NU is concerned that this is mostly due to the availability of customer-funded SREC revenues that ultimately far exceeded what was is necessary to support solar development in the state. The observation of lower prices in other states and need to expand SREC I beyond 400 MW due to rapid development both suggest this.

NU appreciates the benefits of providing price certainty through incentive programs, but think prices should be set through a competitive and transparent process vs. having an administrative process set artificial "floor prices". Observation of programs in CT and RI shows this allows all customers to get the same benefits of solar power at much lower cost. NU has also observed that the complicated Solar Carve-Out design has produced many unanticipated and undesirable outcomes, prompting DOER to intervene and modify regulations several times. NU consequently encourages future policies to be simplified and to avoid reliance on DOER to serve as "market-manager".

NU also believes that any incentives to be distributed should be capped or at least an annual budget amount should be put in place in order to control the total costs of the program.

NU is also not convinced that a mature industry couldn't be sustained through a RPS program without price supports. Sophisticated participants can adequately assess and manage SREC price risk if they have adequate information, reliable regulations and tools to manage volatility (flexible banking, some long-term contract support, etc.). The NJ SREC program has sustained development over the past couple years (~200 MW/yr in 2013 and 2014) with these features despite not having a price floor mechanism and having experienced substantial volatility in the past.

Finally, it is worth comparing the development of the solar industry with that of the energy efficiency industry. In energy efficiency, incentives and rebates are introduced only at the early stages of development, but the primary goal is to phase-out those incentives over time and let the market forces do their work. NU believes it is important to develop an incentive model that has a similar goal in mind and aims to be phased-out over time as market dynamics take a hold of solar deployments.

5. *Other states have implemented a range of incentive program types in order to grow their solar markets. Several program types that you may be aware of include (but are not limited to):*
    - *Standard offer incentive programs (aka. feed-in tariffs)*

- *Declining block incentive programs*
- *Competitiveprocurements (aka. auctions or solicitations)*

There are also many variations on these approaches, as well as co-policies.

Are any of these incentive program types of particular interest to you? Please discuss your impressions of these or other incentive program types that you may be aware of, and whether we should focus on particular incentive types that are of interest to you. How do you think the effectiveness of these incentive program types vary for different solar installation types (e.g. residential vs. utility scale)? What options would you like to see the consulting team consider and analyze for Massachusetts?

NU believes that to the extent state policymakers determine there is a need to provide additional incentives to solar, such incentives should be fair, transparent, appropriate and should be fairly distributed among the customers in the State. Some of our key policy recommendations around incentive structure include:

- DG and solar should only be compensated for benefits that are known, measurable and verifiable and that presently reduce utility cost of service to customers, not on a subjective 'value' to society.
- Incentives should be periodically re-evaluated based on market conditions. Once underlying policy objectives are met or as DG technologies become more cost competitive (or cost prohibitive), such incentives should be modified or discontinued.
- Externalities (job increases, economic benefits, environmental benefits) should be treated consistently for all customers and resource types – for example, there is no difference between utility scale and distributed solar.
- Any solar incentives above the wholesale price of power should be regulated by the DPU.
- Any incentives associated with perceived T&D benefits, should only be provided as part of changes to distribution business models that allow those benefits to be captured and priced.

NU has evaluated and is supportive of models that better provide transparency and drive lower costs to customers. NU has been pleased with the results of long-term contract and tariff programs in CT and RI and would be supportive of a similar, thoughtfully designed program in Massachusetts with the following features:

- Transparent prices set according to a competitive bidding process
- Minimal differentiation between project/customer classes. Policy makers should not insist on supporting higher-cost project types at the exclusion of lower cost alternatives that can provide similar benefits to the system as a whole.
- A tariff design would likely streamline administration and payments and be preferable to entering into a substantial number of long-term contracts.

- NU appreciates the challenge of developing projects when subject to a procurement schedule, so would entertain a Declining Block Design provided Block Pricing was based on transparent analysis and subject to DPU approval.
  - NU also recommend that blocks be priced on a schedule that would end at zero, ensuring that no further programs would be required to sustain solar industry until it was competitive with other resources.
- NU also recognizes that long-term, fixed-price EDC commitments allocate market risk to customers and may be inconsistent with important market-design and restructuring goals. If a Solar RPS is retained for these reasons, the company would recommend it be substantially simplified and not include any price support mechanisms.

6. *During the past year, efforts have been made to revise the framework for net metering in Massachusetts including the addition of a minimum bill for all electricity ratepayers. Please discuss your perspective on the future use of net metering/virtual in Massachusetts and, to the extent you are able, what options or changes would you like to see and why?*

NU believes that policies and regulations related to distributed generation and solar should balance the following objectives:

- Minimize customer bill impacts
- Achieve federal and state energy, environmental and economic policies and goals
- Protect the interests of non-participating customers
- Facilitate customer choice
- Recognize the appropriate costs and benefits of distributed solar technologies
- Acknowledge federal and state energy, environmental and economic policies
- Recover prudent costs of integrated grid services

The Department's long-standing rate design goals are efficiency, simplicity, continuity and fairness:

- Efficiency means that the rate structure should reflect the cost of providing distribution service and provide an accurate basis for consumer decisions;
- Simplicity means that the rate structure should be easily understood;
- Continuity means that rate structure changes should be made in a predictable and gradual manner;
- Fairness means that the rate structure should require no class of customer to pay more than the cost of serving that rate class;

Net metering as it currently stands violates these principles. Proper cost allocation is essential to fair ratemaking and the avoidance of hidden cross-subsidies. Any required allocation of costs to others should be fair, rational and transparent. In order to ensure that net metering or other mechanisms do not result in cost displacement among customers or impose undue costs on all non-distributed generation ratepayers, regulators must ensure that rates reflect equitably the benefits and costs of distributed generation. Deviations from this policy lead to distorted incentives and diseconomies that are not sustainable over time.

NU believes the time is right to implement a new rate design that disaggregates the different elements associated with distributed generation operations and believes this move is essential to further support the deployment of these resources.

- NU proposes to implement new and/or leverage existing measurement technologies, to capture three essential data points associated with distributed generation operations:
  - Power exported to NU at the point of receipt
  - Power delivered to the Customer at the point of delivery
  - Production at the Customer's DG facility

- NU also further recommends a rate design that:
  - Recovers fixed T&D costs for a distributed generation customer at a level consistent with similar non-DG customers
  - Compensates for the energy exported to grid based on the market value of solar in the Massachusetts market
    - One option is to compensate power that meets host load at retail prices, and any excess would be paid at wholesale rates (i.e., P2 rate at NSTAR)
    - Another alternative is to develop some type of value of solar or feed-in tariff methodology
  - Provides additional incentives in a separate transaction if the State so chooses.

- Other alternatives NU wishes to highlight include:
  - Developing a new customer class for distributed generation customers that have capacity or demand charges (not subject to net metering credits) that recover the fixed costs that are being displaced.
  - Higher fixed customer charges and/or demand charges for all customers would also mitigate the cross subsidization issue between customers with and without DER.

In order to move forward, NU's bottom line recommendation is the establishment of a formal regulatory proceeding that can determine appropriate changes to rate design and proper valuation of DER resources where all parties can bring sworn testimony, facts and data to support their positions. The regulatory bodies are established for that precise purpose and should be the proper avenue to develop the long-term changes needed to ensure all State goals are met. Such a proceeding would:

- Determine the quantifiable impact that DER have on the cost to serve electric customers inclusive of:
  - Cost of the distribution system necessary to serve electric customers where DER is not available
  - Cost to serve electric customers who do not receive service from DER

- Consider whether the existing rate design (inclusive of net metering) would fairly and reasonably allocate costs and benefits to DER and non-DER customers
- Determine the impact that DER may have on the equitable collection of reconciling charges on a volumetric basis
- Evaluate other rate design alternatives that might more properly allocate costs and benefits of DER

7. *A. At the 2nd Task Force meeting, it was suggested that analysis should account for uncertainty costs, (i.e., transition costs due to changing goals and programs.) Please discuss qualitatively the nature of these costs as you see them, and whether and how you might suggest such costs could or should be quantified.*

   B. Are there particular threshold milestones where it might make sense to consider policy transitions in order to minimize such costs? What other means are available to minimize such costs?

It is unclear what types of costs are being referenced here. Marketplace is full of uncertainties. Changes to programs occur multiple times and at different places. Any new program being developed should always take into account impact to existing programs to ensure a smooth transition. In addition, any transition costs are outweighed by the above market costs MA is paying to support the deployment of solar.

8. *How would you propose a minimum bill calculation methodology be applied? What other models would you point to that are viable for achieving your objectives?*

NU believes that any minimum bill calculation should be based on higher fixed charges based on the utility's approved embedded cost of service study which functionalizes cost into customer and demand components. NU also believes that minimum bill provisions should be applied to all customers and not restricted to a particular class. Ultimately, NU finds that a minimum bill concept cannot work without proper rate design as presented in answer to question # 6 above.

NU is providing additional information on the minimum bill under a separate attachment.

With respect to FCM revenues for current Class II and III systems, for which utilities secure certain rights under net metering tariffs, please describe your current practices, and future plans.

NU has not offered capacity associated with independent solar facilities into the Forward Capacity Auction. The Company isn't comfortable assuming a capacity obligation associated with a resource it ultimately doesn't control.

Solar resources not offered into the FCM still provide capacity benefits by reducing load and lowering capacity load obligations.

Are utility system integration costs for solar projects now fully borne by project owners?

It is important to note that simplified DG applicants, which are the vast majority of projects at NU, pay no fees to process applications so any costs and effort that the Companies incur to process these applications are not directly recovered by the DG applicants, but recovered from all ratepayers.

In addition, there is no full tracking of DG integration costs (like what NU does for energy efficiency) so there are elements such as customer education, tracking and reporting that are not paid for by DG project owners, but recovered in general rates. It is worth mentioning that with historic test years in Massachusetts and exponentially increasing application volumes, there are real challenges to staffing appropriately for this type of work.

Also ongoing O&M is not currently recovered from project owners. This includes ongoing maintenance of equipment installed solely for DG customers; increase in work for dispatch and account representative to manage planned and unplanned outages; mapping of DG in GIS; regulatory activity, response to customer inquiries when projects go off-line (e.g. transfer trip phone line issues); and training for field workers on DG safety.

What are the expected potential impacts of Grid Modernization/Time-Varying Rates efforts on net metering value and framework?

This is difficult to assess without further information regarding how Grid Modernization and Time Varying Rates will be implemented.

What are your experiences in other state solar markets with alternative incentive models or policies in place?

See above answer to #5.

Please describe your past and expected future participation in SREC floor price auctions.

The company has not yet purchased re-minted auction certificates. The Company purchases energy and RECs to serve Basic Service on a short-term basis (less than 1-year) and re-minted auction certificates have not historically been the lowest cost option to meet short-term requirements. The company would likely seek to purchase re-minted certificates in the future if they were the least cost option for short-term compliance.

Net Metering Task Force - Focus Group Interview
Northeast Utilities Answers
January 23, 2015

9. *Are there any major topics or perspectives related to the Task Force's scope that we have not discussed today that you would like to comment on?*

One major area that has not been asked, but we think it is important to reflect in the final report is the value that the grid provides to DG resources. It is important to note that the benefits of DG systems increase with the level of utility involvement in their deployment – location, size and dispatchability are critical. The grid provides many valuable services to all customers whether they have a DER behind the meter or they do not have DER. Ultimately, it would be very expensive to replicate the reliability that the grid provides to DER customers on a stand-alone basis.

Here are the key operational areas of value that the grid provides to all customers:

- Reliability - Provides power when DER fails and compensates for variable output of DER.
- Frequency regulation- Through instantaneously balancing supply and demand, grid provides electricity at a consistent frequency.
- Real and Reactive Power Balancing - Balancing extends beyond real power, as the grid also ensures the amount of reactive power in the system balances load requirements and ensures proper system operation.
- Redundancy - With the grid redundant capacity can be polled among multiple customers, rather than each customer having to provide its own backup resources.
- Start-up power - Grid provides instantaneous power for appliances and devices such as compressors, A/C, transformers, welders that require a strong flow of current when starting-up. An A/C using just PV to start-up won't able to do so, unless it is oversized to handle this in-rush current.
- Voltage regulation/quality & harmonic distortion - Grid allows customers to experience voltage levels within narrow bands with little harmonic distortions. Voltage from a DG installation that is not connected to the grid experiences higher voltage harmonic distortion which can damage sensitive consumer end-devices. Harmonics cause heating in many components, which can reduce the life of the equipment.
- Efficiency - Grid connectivity allows rotating-engine based generators to operate at optimum efficiency which is operating steadily near full output. A distributed energy resource, not connected to the grid, would have to match load on an instantaneous basis limiting the option to run at close to full output, reducing efficiency by as much as 10-20%.
- Energy transaction - Grid provides the ability to install any size DG that they want. Utility connection allows the consumers to transact energy with the utility grid, getting energy when customer needs and sending energy back when the customer is producing.

These services need to be valued as part of any cost/benefit analysis. Attached to this response we are providing a copy of EPRI's Integrated Grid paper that summarizes the elements above.

APPENDIX B: Task Report 3 Appendices

Appendix A:

Task 3 - Analysis of Costs and Benefits: Key Assumptions

Massachusetts Net Metering Task Force

PEREGRINE ENERGY GROUP

Sustainable Energy Advantage, LLC

MEISTER CONSULTANTS GROUP

La Capra Associates

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(2)

A. OVERARCHING ASSUMPTIONS & SIMPLIFYING ASSUMPTIONS

& SIMPLIFYING ASSUMPTIONS

(3)

Key Assumptions

- Analysis performed, and metrics, in Nominal $
- Tax Rates
  - Massachusetts Tax Rates = 8%
  - Federal Tax Rates = 35%
- Nominal Discount rate = 5%
- Federal Investment Tax Credits (ITC) were not assumed to be extended beyond their current statutory timeframe.
- General inflation rate from EIA AEO 2014 GDP IDP
- Inflation rate for ACP from EIA AEO 2014 CPI All Urban Customers

(4)

MA DG Solar Avoids Electric Losses

Raw Data (Utility-specific average & peak loss factors)

		Average T&D	Peak T&D	Avg. excl. TX losses	Peak excl. TX losses
Wtd. Avg MA		5.15%	8.62%	4.35%	7.34%
	weight				
NSTAR	45.28%	4.70%	6.60%	3.77%	5.300%
WMECO	7.79%	5.00%	9.78%	4.45%	8.70%
NGRID - MECO	45.69%	5.60%	10.38%	4.90%	9.077%
NGRID - NEC	0.31%	5.60%	10.38%	4.90%	9.08%
FG&E	0.92%	5.60%	10.38%	4.90%	9.08%

Blue: provided by EDCs
Black: imputed based on similar relationships of peak to average data in blue
Red: used other EDC data as proxies

For Solar Impact ➔ Statewide 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%

Production weighting reflects higher-than-average loss reduction due to peak coincidence
(developed using inferred square-function matching average and peak losses)

(5)

Key Considerations for Understanding Results:
Implications of Simplifying Assumptions (1)

1. **Retail Rate Structures Held Constant.** Assumed no change in retail rate structures from current, 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 ➔ Would diminish economics, lead 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).
   - However, this analysis assumes that a subsector of the marketplace whose retail rate value is not hedged through fixed-price PPA or discount arrangements would derate expectations of future rate revenue to some degree to account for exposure to change of rate structure risk (i.e., host owned <= 25 kW systems under SREC or Path B)
2. **Distribution System Saturation Ignored.** Did not explicitly examine limitations on development caused by saturation of distribution feeders or resulting elevated interconnection costs. Considering such factors would slow the pace of development.(forecast of installations does consider interconnection timelines/constraints).
3. **Technical Potential Saturation Largely Ignored.** Did not explicitly constrain solar technical potential. However, modeling does consider land area, population density, number of residential customers and number of non-residential customers in regards to growth rates and relative potential among utilities. Paths A&B have low growth rates and are not likely to be constrained by technical potential, but are constrained by the policy mechanism itself. Path B is constrained economically. Separately, we have done research that did not find significant near term constraints on brownfield, landfills, or VNM low-moderate income housing sub-sectors.

(6)

Key Considerations for Understanding Results:
Implications of Simplifying Assumptions (2)

4. **Ignored Potential Differential Impacts of Installer Incentive Capture.** Did not explicitly assume or analyze installed cost inflation under the more 'generous' policy options (compared to less generous policies), an installer 'incentive capture' phenomenon cited by some analysts, or assume lower installed costs for Policy futures with less generous combined solar and NM incentives.

5. **Ignored Impact of ITC Qualification Peril at 1/1/17.** Did not reflect the likelihood that projects are unwilling to commit to projects with risk exposure to loss of ITC due to interconnection delay or labor shortages in 2016, which may in practice lead to a risk-aversion-driven drop-off in development. Simplified to assume a steadier rate of development influenced by economics and shifted some development back to earlier in the year as participants are well aware of the pending loss of ITC, the risk in being late and are starting development activity earlier.

6. **Assumed Municipal Light Plants Participate Like IOUs in Policy Paths A & B.** MLPs are assumed to participate in Policy Paths A&B the same way as do investor owned utilities (including allowing or not allowing virtual net metering in capped and uncapped scenarios). We treated all MLPs as having a single prototypical rate structure based on Taunton Municipal Lighting Plant rates.

7. **Assumed Future LSE Participation in SREC Floor Price Auctions.** LSEs will fully participate in auction and thus hold marginal SRECs during the auction out years. If LSEs continue to stay on sidelines, it causes extreme additional expenses for NPRs ➔ seems imprudent to assume that this practice would continue indefinitely.

(7)

Key Considerations for Understanding Results:
Implications of Simplifying Assumptions (3)

7. **Ignored Nantucket as a location for solar development.** Did not include Nantucket Electric in the primary analysis

8. **Reclassified SREC-I Projects into SREC-II Sectors.** In order to provide SREC-I results in a comparable manner to other policy paths, we have made best guesses of project reclassification to SREC-II subsectors. Assigning SREC-II subsectors provides a basis of computing and reporting build-out, revenue and cost and analysis.

9. **Treated All Towns as Served by Single Distribution Utility.** In order to assess potential for different project types, utility square miles were computed. Some Massachusetts towns are served by multiple utilities. We assigned each town a unique utility in order to simplify the calculation.

(8)

B. SOLAR PV MODELING

FOR DISPATCH ANALYSIS ANDS COST & BENEFIT ANALYSIS

(9)

Solar PV Production Modeling
Technical Assumptions (1)

- Analysis requires understanding:
  - How many MWh produced per DC MW PV installed?
    - # of SRECs (current policy) is less than this #
  - When production occurs?
    - Value of energy; Coincidence with applicable peaks
- 25-year economic Life of Solar PV Installations
- Key & Simplifying Assumptions:
  - Ignore technological advance and change in mix of fixed vs. tracking
    - Performance (profile and capacity factor) held constant for each installation type across analysis horizon and policy path
  - Degradation: 0.5% energy production per yr.
- AC vs. DC
  - PV rated @ Direct Current (DC)
  - Inverters convert to AC (Alternating Current)
  - Energy on the grid is AC
  - Solar Policy Goals are stated in DC
  - DC to AC conversion efficiency varies by installation type
- Annual Production:
  - Use "Proxy" profile representing simplified composite of different installation types
  - Installation composition may vary over time
  - PV Watts (NREL model estimating production @ specified location) used to estimate production volume and timing
  - PV Watts requires assumptions on tile, azimuth (degrees from due south), AC to DC ratio determinates, shading, etc.
  - MA CEC's Production Tracking System (PTS) provides performance details on current MA PV fleet
  - SEA studied PTS data on existing fleet, developed 'standard' installation characteristics for **composite project type**: Residential, C&I Rooftop, Ground Mount and Solar Canopy installations
  - SEA assumed fraction of each SREC-II subsector associated with each composite project type
  - For PV Watts, assumed single location (Worcester)
- Results: Year 1 for any installation for current SREC-II fleet
  - Capacity Factor (c.f.) (DC) = 14.3%
  - Annual energy: 1627 kWh per AC kW installed
  - Annual energy: 1253 kWh per DC kW installed

(10)

Solar PV Technical Assumptions
Application to Modeling of Solar Policy & Net Metering Impacts (2)

- Each SREC-II subsector has:
  - Composite proxy profile (constant c.f. and production profile over time)
  - Economics of each subsector vary under each policy path ➔ different quantity of PV installed for each subsector under each policy path
  - Policy-path-specific blend of composite profiles and installation proportions ➔ aggregate annual PV production in each year ➔ "Portfolio Annual Production"
    - c.f. was held constant over time and between policy paths as a simplification

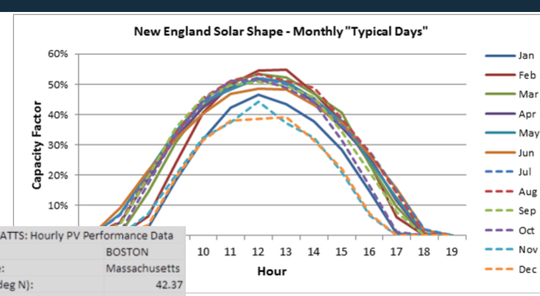
- Area for potential future study:
  - Allow performance over time to vary with evolving blend of system types
  - More nuanced profile as weighted average of projects of varying technology, orientation, tilt, etc.
  - Consider technology advance
  - Would allow looking at possible benefits of encouraging more peak-value orientation, etc.

Residential System	Commercial Rooftop	Ground Mount	Solar Canopy
16%	18%	63%	3%

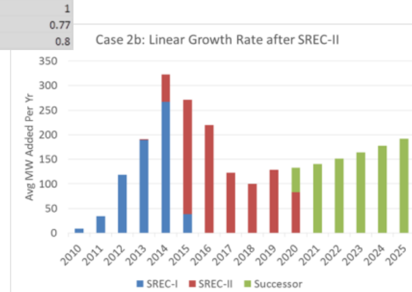
(11)

Solar PV Technical Assumptions
Application to Modeling - Production Modeling in Aurora (3)

- Applies to: market value, energy market price impacts, emission impacts
- Uses a single standard proxy profile of average day per month based on PV Watts profile, 0.77 AC/DC (Boston) (see graph and table: 14% annual c.f. (DC); 1593 kWh per AC kW
  - Same as DOER 2013 Task 3B report
- MW targets in DC
- Modeling convention: Policy paths have similar solar PV build-out quantities
  - Small differences will not alter per-MWh values materially
- Results of a single Aurora build-out analysis (graph) ➔ scaled to *projected* portfolio annual production in each case using per-MWh Aurora result values

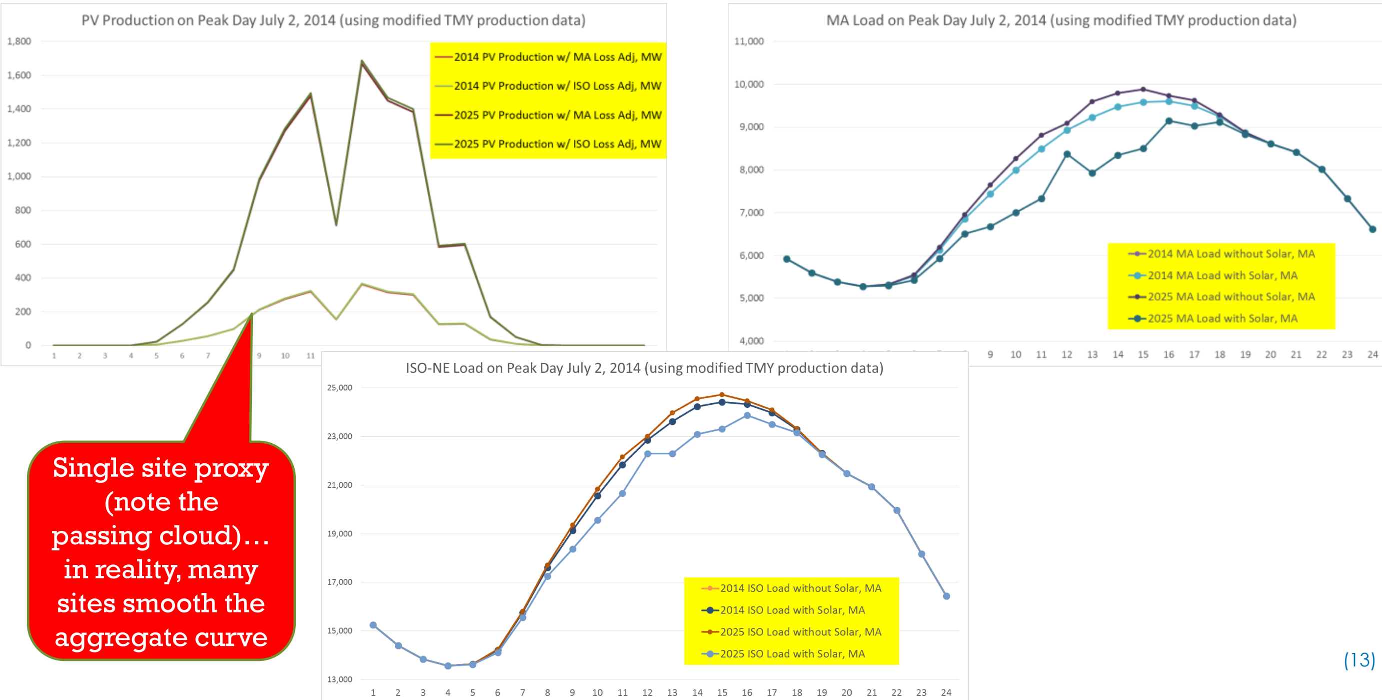


PVWATTS: Hourly PV Performance Data	
City:	BOSTON
State:	Massachusetts
Lat (deg N):	42.37
Long (deg W):	71.03
Elev (m):	5
Array Type:	"Fixed Tilt"
Array Tilt (deg):	42.4
Array Azimuth (deg):	180
DC Rating (kW):	1
DC to AC Derate Factor:	0.77
AC Rating (kW):	0.8



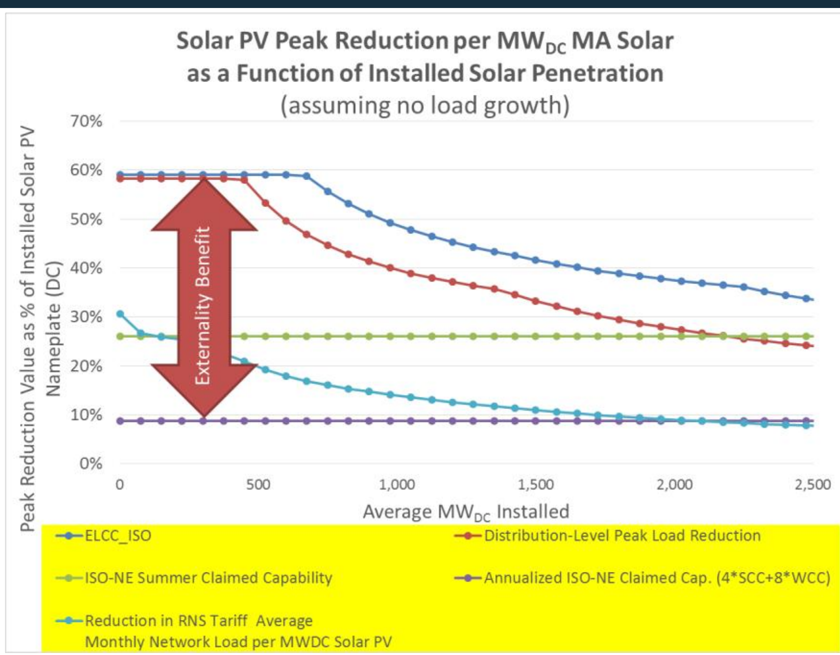
(12)

Solar Peak Impact



(13)

Solar PV Impact on Avoiding G, T & D Capacity



- ISO-NE FCM value (purple):
  - Doesn't vary with PV MW
  - Well below impact on reducing peaks until PV penetrations >> 2500 MW
- Actual PV impact on peaks declines with penetration
  - PV has high peak coincidence
  - But starting to shift time of peak
  - Eventually: the CA 'Duck Diagram'
- G&T peak reduction value (blue) somewhat higher than Distribution value due to different timing of peaks
- Difference between *actual* impact (e.g. lower ISO ICR) and value in FCM market is a *benefit* to all citizens of MA
- FCM value not monetized by generators also a *benefit* to all citizens of MA

(14)

C. WHOLESALE MARKETS & PRODUCTION DISPATCH MODELING ASSUMPTIONS

DISPATCH MODELING & COST/BENEFIT ASSUMPTIONS

(15)

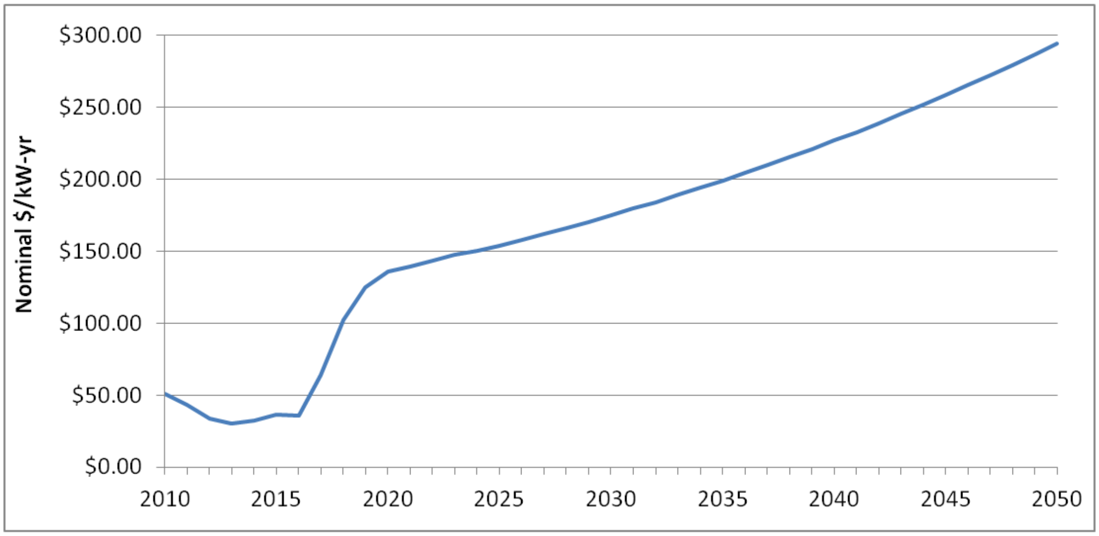
Wholesale Market Assumptions

- ISO-NE Transmission Tariff:
  - 2014 RNS Tariff Rate = $89.80/kW-yr
  - 2014 RNS MA Load Ratio Share = 43.59%
- Installed Capacity Reserve Margin
  - Per ME VOS study, for the year 2017/18, the ISO New England reserve margin was 13.6% based on Net ICR

(16)

Capacity Market Assumptions

- Capacity market prices = Historic actuals, projected values taken from CT 2014 IRP, adjusted to nominal using AEO 2014 GDP deflator, and converted to calendar year



(17)

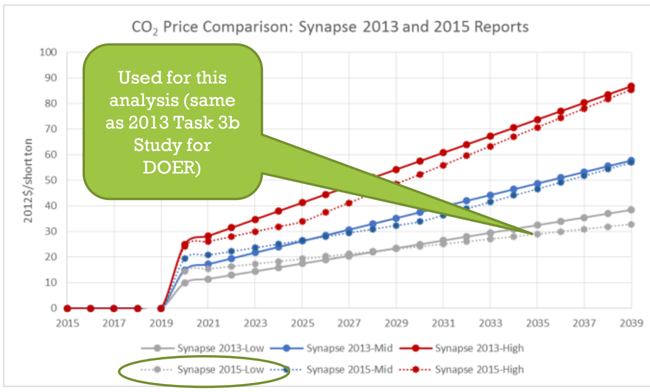
Capacity Value of Intermittent Resources

- Intermittent Resources per : ISO-NE Commercialization and Audit/CCA Establish Procedures for FCM resource (ISO-NE, Apr. 17, 2014)
  - Intermittent reliability hours
  - http://iso-ne.com/static-assets/documents/committees/comm_wkgrps/othr/vrwg/mtrls/a4_commercialization_and_audit.pdf
  - Comparative benchmark for SCC: See slide 20 of this:
    - http://www.iso-ne.com/static-assets/documents/2014/08/2014_final_solar_forecast.pdf
    - 35% SCC used by ISO for estimate

(18)

Internalized (Market) CO_2 Price Assumptions
Used in Dispatch Modeling

Potential Future Carbon Pricing or Equivalent LMP Impact of GHG Regs



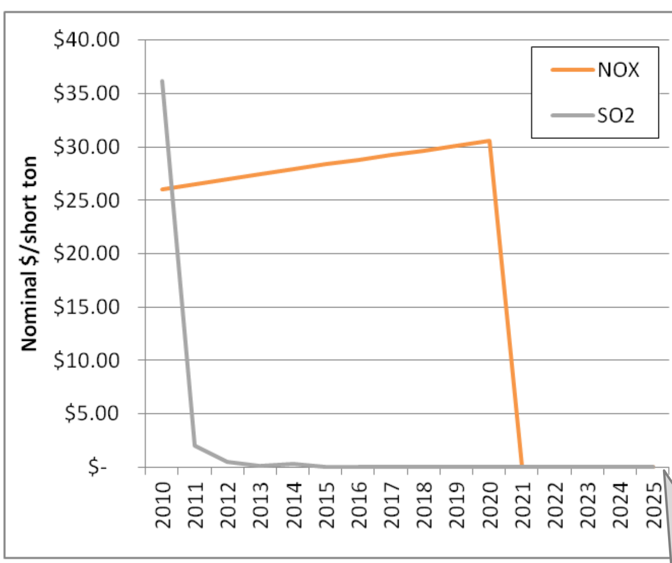
Note: Potential sensitivity of interest for further study: higher carbon price future

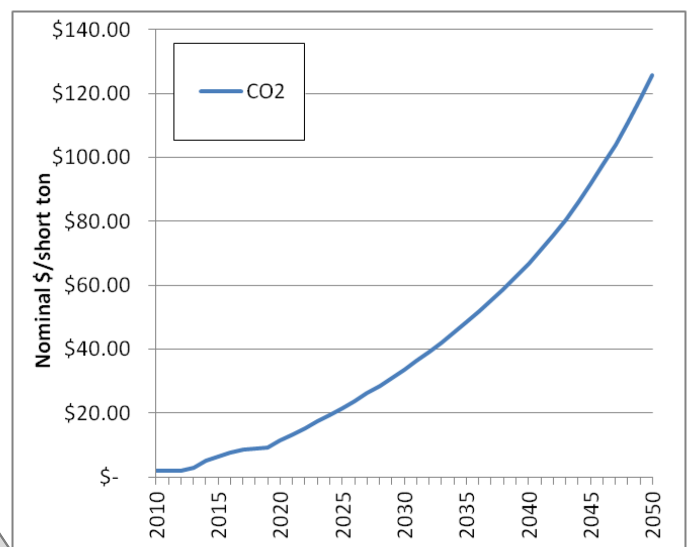
Used as a PROXY

- Start with: Regional Greenhouse Gas Initiative (RGGI) past and projected pricing (projections by ICF for RGGI)
- Transition after 2019 to Synapse Low as a proxy for some combination of future:
  - Federal cap & trade
  - Federal Clean Power Plan impact on energy costs
  - MA Global Warming Solutions Act (and other regional state carbon regs) impact on energy prices

(19)

Emission Pricing Assumptions for Dispatch Modeling

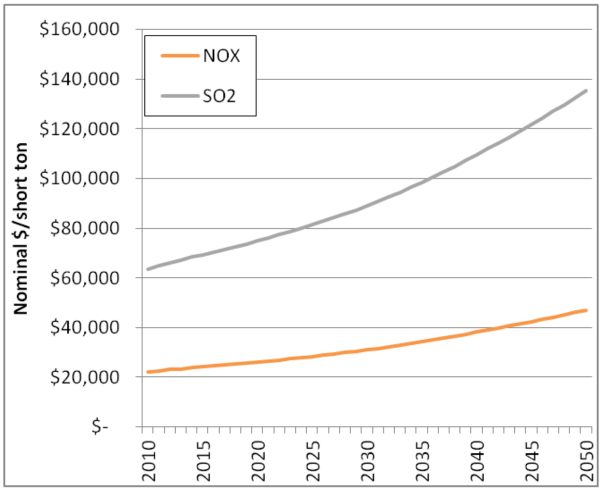


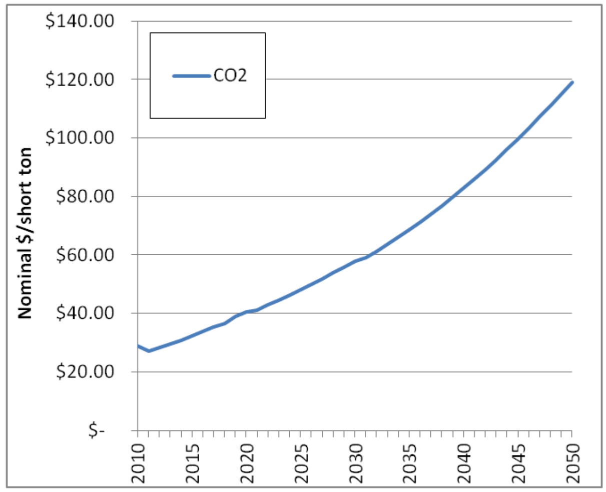


Remains $0 from 2025 onward

(20)

Gross Social Costs of Emissions





- Social costs of NO_X and SO_2 are taken from Table 4-7 of the 2014 EPA "*Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants*" report
- Social costs of CO_2 are taken from Table A-1 of the 2013 "*Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis*" prepared by U.S. Interagency Working Group on Social Cost of Carbon under Executive Order 12866

(21)

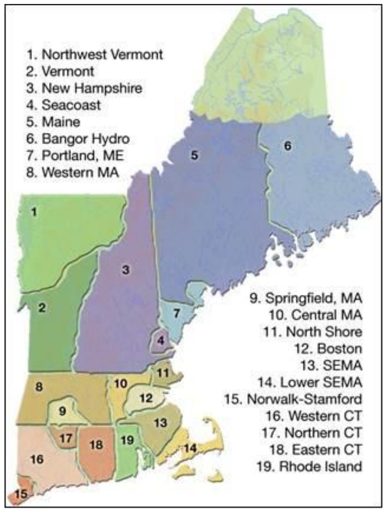
Production Modeling of Impacts (1)

- Case 1a: no policy: remove SREC-I & SREC-II production (keep pre-carve-out PV), assume Class I RPS is met by adding a commensurate amount of wind or (if fall short) natural gas
  - In past, before 1/1/2015 not modeled. Instead:
    - solar not replaced by other supply (onshore wind) but rather all the wind that could be built, was, so RPS supply came up shorter by the amount of SRECs projected, and replaced to the extent supply needed by natural gas
    - Fuel use and emissions changes not modeled; rather, calculated at marginal values
    - Was negligible congestion historically → assume same marginal units (modeled as hypothetical NG unit at composite marginal heat rate
    - Assume no material change in LMPs
  - In future: through 2017 assume no more wind could be built, so substituted by falling short of RPS, met be marginal natural gas; 2018 & thereafter, assume PV substituting with land-based wind
- Case 1b: Assume RPS shortfall made up by natural gas
- Case 2a: 1600 MW by 2020
  - Buildout: Historic (from DOER) + projected (SEA MA-SMS in consultation w/ DOER)
- Case 2b: 1600 MW by 2020 continuing to 2500 MW by 2025
  - Buildout: Extrapolate normalized build per yr and round up to allow for a bit of growth
- Impacts calculated as differences:
  - SREC-I & SREC-II from difference between Case 1 & Case 2a
  - SREC-I, SREC-II & (projected) SREC-III from difference between Case 1 & Case 2b

(22)

Production Cost Modeling (2)

- Geographic distribution assumed to be same as current cumulative build
  - BOSTN = 11 North Shore + 12 Boston
  - CMA = 10 Central MA
  - WMA = 8 Western MA + 9 Springfield
  - SEMA = 13 SEMA + 14 Lower SEMA



- Note: the Aurora modeling was done using a slightly older SEA forecast (vintage Dec. 2014) of SREC Carve-out (current policy) than used for Policy Path A & B.
- SEA's March 2015 Solar Market Study model is better able to address the differential economics of alternative policy paths.
- March 2015 model projects hitting 1600 MW under current policy at a somewhat different pace.
- Use of per-MWH Aurora results scaled to SMS MWH projections used to correct for this difference.

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MA DOER Net Metering

Modeling Assumptions

Presented by: *La Capra Associates, Inc.* **Presented to:** **Sustainable Energy Advantage, LLC**

April 21, 2015

La Capra Associates

Introduction: Modelling Overview

- The La Capra Associates NMM uses an hourly chronologic electric energy market simulation model based on the AURORAxmp® software platform (AURORA). The model provides a zonal representation of the electrical system of New England and the neighboring regions. For New England, the zones and corresponding transfer capabilities represented in the model conform to the information provided in ISO New England's Regional System Plan.
- AURORA is a well-established, industry-standard simulation model that uses and captures the effects of multi-area, transmission-constrained dispatch logic to simulate real market conditions. AURORA realistically approximates the formation of hourly energy market clearing prices on a zonal basis using all key market drivers, including fuel and emissions prices, loads, DSM, generation unit operating characteristics, unit additions and retirements, and transmission congestion and losses to capture the dynamics and economics of electricity markets.
- The NMM utilizes a comprehensive database representing the entire Eastern Interconnect, including representations of power generation units, zonal electrical demand, and transmission configurations. EPIS, the developer of AURORA, provides a default database, which La Capra Associates supplements with updates to key inputs for the New England market.

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Modeling Assumptions

- Case assumptions
- Environmental Policies
- Regional Demand and DSM
- Regional Generation
- Transmission
- Natural Gas

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Four cases run in Aurora

Case 1: No SREC Carve-out (removes MA SREC I and II) and replaces solar with wind resources beginning in 2018

Case 1b: No SREC Carve-out (removes MA SREC I and II)

Case 2a: 1600 MW of solar by 2020 (Current Policy)

Case 2b: 1600 MW of solar by 2020 and continuing to 2500 MW by 2025 with linear growth

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Environmental Policies

- There are two major policy issues affecting the regional market outlooks.
- The two programs particularly impact decisions on generation resource continued operation and new supply choices.

1. The continued strong support for Renewable Portfolio Standards
2. The existing and developing GHG regulations

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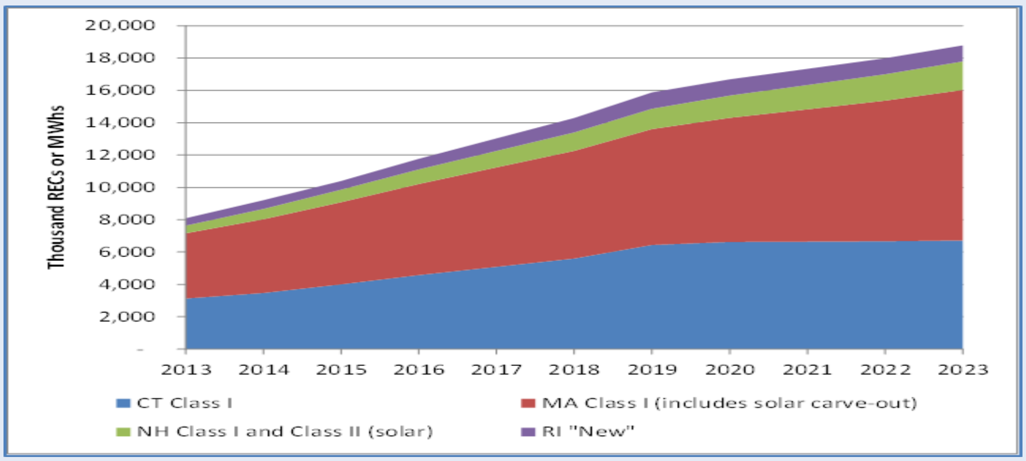
Renewable Energy - Premium Markets RPS

	2014	2015	2016	2017	2018	2019	2020	2021-2023
CT Class 1	11.0%	12.5%	14%	15.5%	17%	19.5%	20.0%	20.0%
MA Class 1	9%	10%	11%	12%	13%	14%	15%	16%+
NH Class 1	5.0%	6.0%	6.9%	7.8%	8.7%	9.6%	10.5%	11.4%+[1]
NH Class 2	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%
RI New	6.5%	6.5%	8.0%	9.5%	11.0%	12.5%	12.5%[2]	12.5%
Load-Weighted Average	9.0%	10.1%	11.2%	12.4%	13.6%	15.1%	15.9%	16.5%+



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Greenhouse Gas Regulations

RGGI

All New England states participate in RGGI, a cap-and-trade program aimed at reducing CO_2 emissions from the power sector. Pricing carbon emissions through a cap-and-trade program affects New England electric energy prices by increasing the variable costs of fossil fuel-fired generators that are almost always on the margin. RGGI allowance prices have been minimal since the program began in 2009 because actual CO_2 emission levels have fallen well below the initial program caps. On February 7, 2013 the RGGI states committed to an Updated Model Rule that would tighten the caps significantly in 2014. A RGGI-commissioned study of the Updated Model Rule projects that emission allowance prices will rise from about $4 (2010$) per ton in 2014 to over $10 (2010$) per ton by 2020.RGGI auction results to-date have benchmarked well to the Updated Model Rule forecast. After 2020, the reference case assumes that a national CO_2 pricing program is implemented and that prices will reflect the "Low" case of Synapse Energy Economics, Inc.'s 2012 Carbon Dioxide Price Forecast.

Federal Policy

EPA released its Clean Power Plan proposal, which aims to cut carbon emissions from existing power plants and enable the US to reduce carbon emissions from the power sector by 30% below 2005 levels. EPA has proposed each state or multi-state collaboration would develop a plan to meet an individual carbon intensity reduction target through any combination of plant efficiency improvements, shifting generation from higher to lower-emitting resources, maintaining and expanding nuclear and renewable generation, and energy efficiency. New England has already implemented programs and policies that would likely generate more carbon dioxide reductions than required under the EPA's proposal, but the federal proposal would backstop these efforts.

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Regional Electric Demand – Gross Outlook Pre - EE

ISO-NE Peak Demand Outlook

▪ 2013 Normalized Demand		Actual 27,941	MW
▪ 2014 Forecasted Demand		28,290	MW
▪ 2023 Forecasted Demand		31,878	MW
▪ 10 Year CAGR			1.4 %
▪ 10 Year Increase	3,937 MW	11% of 2023 Demand	

ISO-NE Energy Requirements Outlook

▪ 2013 Energy		*est. 135,000*	GWh
▪ 2014 Forecasted Energy		138,910	GWh
▪ 2023 Forecasted Energy		152,347	GWh
▪ 10 Year CAGR			0.7%
▪ 10 Year Increase	3,006 GWh	10% of 2023 Energy	

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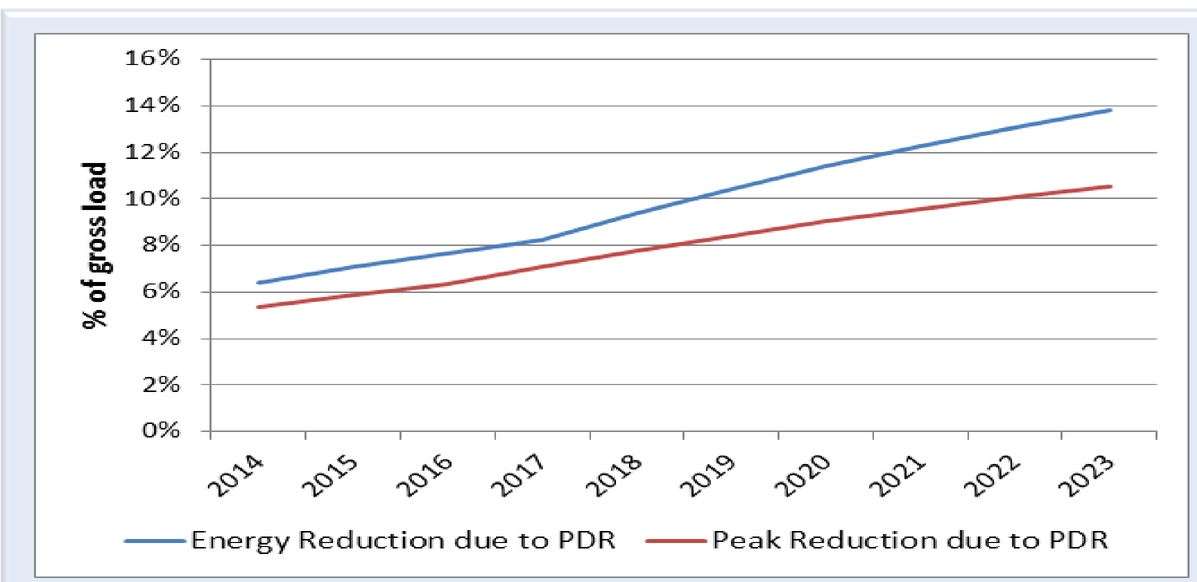
Energy Efficiency Resources



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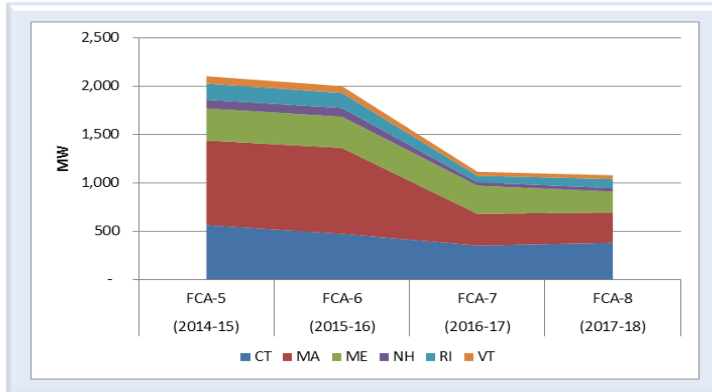
Active Demand Response Resources

- **There has been a major reduction in the amount of active DR available to ISO-NE by 201-18**
- **Total reductions are approximately 1,000 MW**
- **Proportionately largest reduction in Massachusetts**
- **This is primarily a result of the new rules requiring DR participation in energy markets**
- **Further operational requirements on DR could virtually eliminate DR as an FCA resource**



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Regional Electric Demand – Net Outlook after EE Effects

ISO-NE Peak Demand Outlook

2013 Normalized Demand	*est 26,000*	MW
2014 Forecasted Demand	26,929	MW
2023 Forecasted Demand	29,206	MW
10 Year CAGR		0.7 %
10 Year Increase	3,006	MW

ISO-NE Energy Requirements Outlook

2013 Energy	*est. 134,000*	GWh
2014 Forecasted Energy	131,037	GWh
2023 Forecasted Energy	134,786	GWh
10 Year CAGR		0.1 %
10 Year Increase	786	GWh

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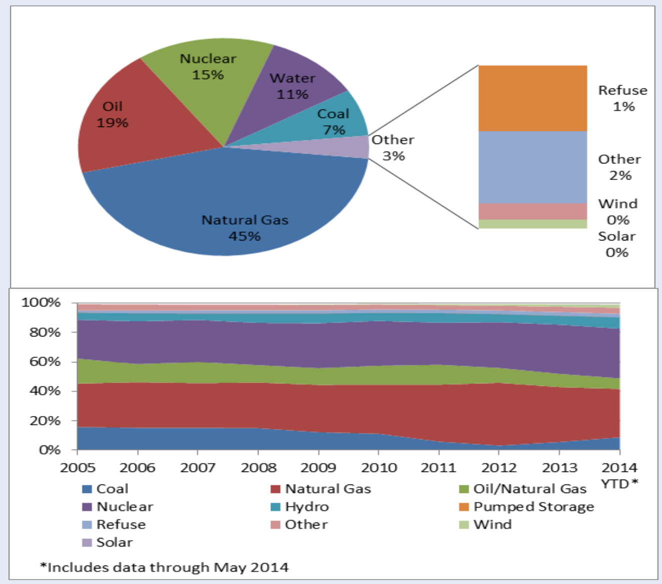
Generation Mix

- New England remains a natural gas fueled dependent region
- Renewables have not yet been established as a major component of generation mix
- Natural Gas share of energy increased every year until its highest in 2012, before regional constraints began to push natural gas prices upward



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Generation Resource Retirements

Name	Capacity (MW)	Location	Fuel Type	Status	Planned or Actual Shutdown
Vermont Yankee	600	Vernon, VT	Nuclear	Shutdown Announced	End of 2014
Brayton Point (Units 1-4)	1,500	Somerset, MA	Coal/Oil	Shutdown Announced	2017
Salem Harbor (Units 1-4)	750	Salem, MA	Coal/Oil	Closed	2011-2014
AES Thames	450	Montville, CT	Coal	Demolition	2011
Mt. Tom	150	Holyoke, MA	Coal	Shutdown Announced	2014
Bridgeport Harbor 2	130	Bridgeport Harbor, CT	Oil	Shutdown Announced	2017
Norwalk Harbor (Units 1, 2, 10)	350	Norwalk, CT	Oil	Deactivated	2013

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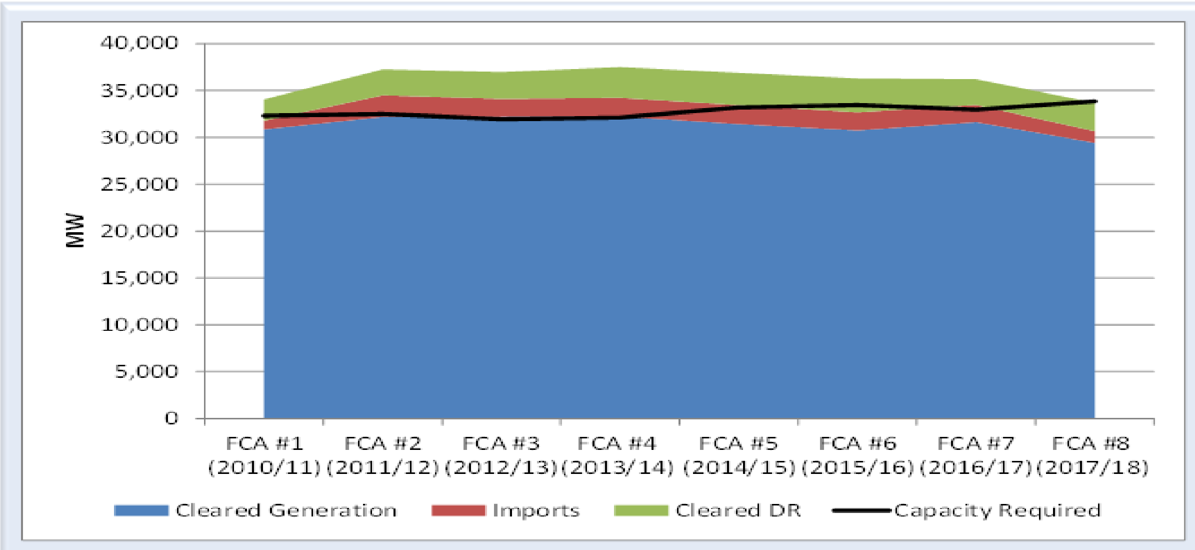
Regional Capacity Outlook

ISO-NE FCA Results showing slight shortfall in 2017/18



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Regional Transmission Developments

There are several other transmission projects currently planned or under construction in New England:

- **Maine Power Reliability Program:** six new substations, upgrades to numerous existing substations, and the installation or rebuilding of 440 miles of transmission line in the communities from Eliot to Orrington in Maine. Expected in service date is 2015.
- **New England East-West Solution:** a group of related transmission projects addressing reliability needs in New England, including:
  - **The Greater Springfield Reliability Project:** upgrades to 39 miles of transmission lines between Ludlow, MA and Bloomfield, CT. Now fully in service.
  - **The Interstate Reliability Project:** transmission upgrades spanning three states on a line from Millbury, MA to Card Street Substation in Lebanon, CT. Expected in service date is December 2015.
  - **Central Connecticut Reliability Project:** a project currently in development to remedy reliability concerns in the central Connecticut area**.**
  - **Rhode Island Reliability Project:** includes several transmission upgrades in Rhode Island, including a new 345 kV line from West Farnum to Kent County. Now in service.
- **Boston Upgrades:** transmission upgrades due to the retirement of Salem Harbor and advanced NEMA/B**oston upgrades increasing Boston import capability in 2014.**

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Natural Gas Pricing Methodology

- ***Henry Hub:*** **Prices are a blend of EIA's December 2014 Short-Term Energy Outlook (2013-2015) and EIA's 2014 Annual Energy Outlook (AEO) (2015 and after). In the early years, we rely on the Short-Term Energy Outlook. For years 2017 and 2021, we smooth our forecast by assuming that the price rises at a constant rate. In 2021 and beyond, our forecast follows the AEO2014 exactly.**
- ***New England Basis Differential:*** **We developed our near-term basis differential outlook using the average across a recent one year period (1/6/14 – 1/5/15) of daily closing quotes for February 2015 to January 2016 Algonquin City-gates basis swaps. In 2018 and beyond, we revert to a basis that results in a delivered natural gas price equal to the AEO2014 Reference Case forecast for delivered prices to the New England electric industry. We make a straight-line interpolation for basis differential values between 2015 and 2018.**

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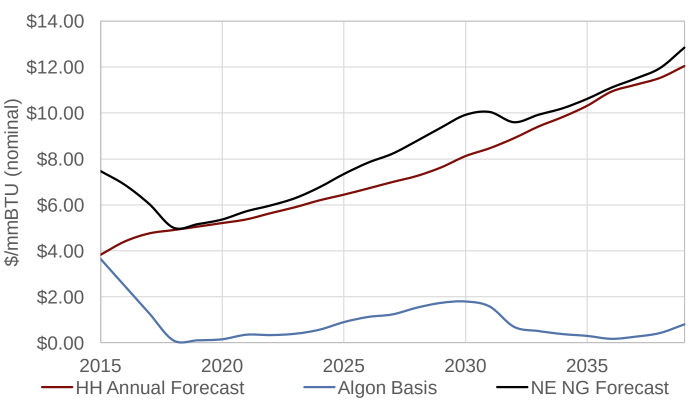
Natural gas price inputs in nominal dollars



Year	HH Annual Forecast	Algon Basis	NE NG Forecast
2015	$3.83	$3.64	$7.47
2016	$4.41	$2.46	$6.87
2017	$4.76	$1.28	$6.04
2018	$4.91	$0.10	$5.01
2019	$5.06	$0.11	$5.17
2020	$5.21	$0.15	$5.37
2021	$5.37	$0.35	$5.72
2022	$5.64	$0.34	$5.98
2023	$5.90	$0.39	$6.30
2024	$6.20	$0.57	$6.77
2025	$6.45	$0.90	$7.34
2026	$6.72	$1.12	$7.84
2027	$7.00	$1.23	$8.23
2028	$7.26	$1.53	$8.79
2029	$7.63	$1.73	$9.37
2030	$8.12	$1.79	$9.92
2031	$8.47	$1.57	$10.04
2032	$8.91	$0.69	$9.60
2033	$9.41	$0.51	$9.92
2034	$9.83	$0.38	$10.21
2035	$10.31	$0.30	$10.61
2036	$10.93	$0.17	$11.10
2037	$11.23	$0.27	$11.50
2038	$11.53	$0.43	$11.96
2039	$12.04	$0.80	$12.84

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End of Presentation

▪ ▪ ▪

Additional Discussion or Questions ?

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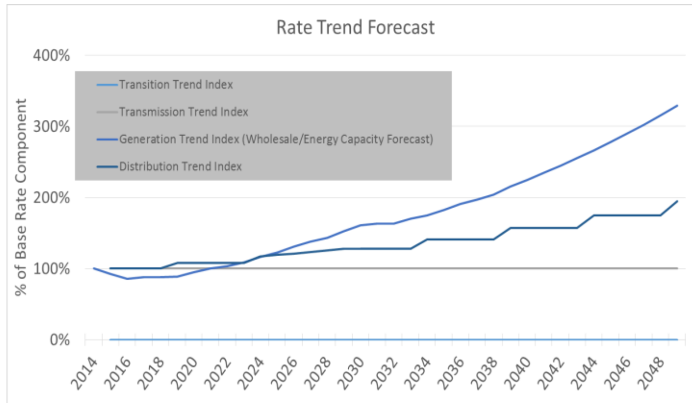
D. AVOIDED RETAIL RATES AND NET METERING REVENUES

AND RELATED ASSUMPTIONS

(42)

Rate Trend Forecast:
Assume no fundamental change in rate structures over time

- **Transition** assumed to be 0% escalation after 2015, per EDCs
- **Transmission** assumed to be fixed (0% escalation), per EDCs
- **Distribution** assumed to increase by inflation in steps (corresponding to rate cases) every 5 years, per EDCs
- **Generation** assumed to escalate at index of wholesale blended energy (75%)/capacity (25%)* trend forecast
- **Other Rate Components**: Increase with Inflation, per EDCs
- Recent difference between wholesale energy prices and Basic Service generation rates applied to factor in impact of capacity, reserves, losses, etc.
    - Average of 2014 basic service rates (two procurements) used as the base for forecasting generation charge to avoid overstatement due to unusually high 2015 winter basic service rates

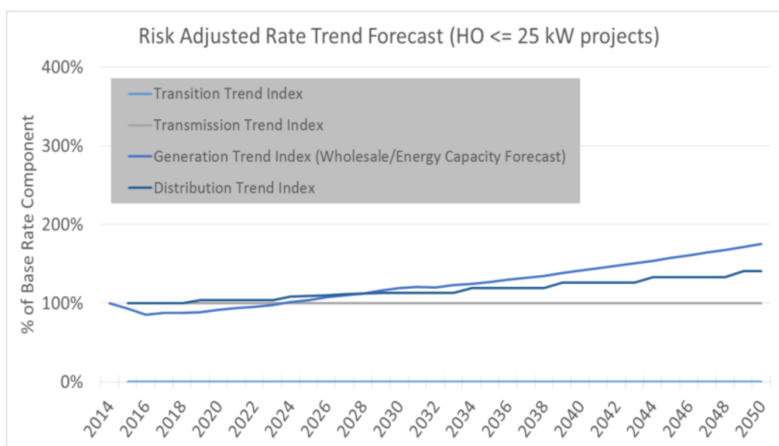


* Portion of spread to trend @ Energy vs. capacity escalator

(43)

Rate Trend Forecast:
For Modeling Project Threshold Return Requirements

- Generators cannot take the uncertain projected retail revenue stream, dependent on long-term factors like carbon pricing, natural gas pricing and capacity market prices, which cannot be relied upon, to the bank
- For 3rd-party owned projects, this risk can and often is hedged (i.e., passed along to the host or NMC off-taker through a fixed-price transaction). We assume going forward that this risk is hedged in such a manner for all 3rd-party owned systems
- For host-owned small projects (<= 25 kW) under SREC and Policy Path B, we assume project owner is exposed to future retail price risk, and makes choices based on a more conservative outlook of future retail rates
- Modeled more conservative future by halving the year-to-year growth in prior slide of **generation** and **distribution** rates after 2018
- Otherwise, under PBIs as studied in Paths A and B, the combined incentive structure serves to hedge this risk



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‘Generic” Municipal Light Plant Modeling

- Municipal light territories are modeled in aggregate
- Net metering credit assumed to be load-weighted average of a sample of 10 MLP NMC values (Taunton rates were used as proxy to differentiate G rate from other charges)
  - NMC escalated at wholesale/energy capacity forecast index
- Residential and commercial retail rates calculated as the ratio of EIA “loaded” $/MWh (includes non-kWh charges) of IOUs to MLPs applied to the actual “unloaded” IOU retail rates
  - 40% of MLP retail rate escalated by wholesale/energy capacity forecast index
  - 60% of MLP retail rate escalated by CPI
- Assume 13% of installations in 2015 are in MLPs - based on historic installation trends
- For calculating rate component value, assume MLP rates are made up of basic service (40%), distribution (40%), and transmission(20%)

<u>Errata Note</u>: rates used were 20% higher than avg. MLP. This was an error discovered too late in the analysis for revision. Correction of this error would modify results in the following manner: overall growth in installations in the MLP sector would slow moderately, and the overall cost of solar incentives would be slightly higher. This does not alter the nature of overall conclusions in a material manner.

Applicable Rate Class & Net Metering Class Assumptions

Description	Rate Class	% NM Beyond Billing Month/VNM	% BTM Production w/in Billing Month	Net Metering Class Assumed		
				3rd Party	Host Owned	Public Owned
Residential Roof Mount	R-1	10%	90%	Class 1		
Small Commercial Roof Mount	G-1	5%	95%	Class 1		
Solar Canopy	G-1	5%	95%	Class 2		
Commercial Emergency Power	G-1	5%	95%	Class 1		
Community Shared Solar	G-1	100%	0%	Class 2		
On-Site LIH	G-2	5%	95%	Class 2		
VNM LIH	G-1	100%	0%	Class 2		
Building Mounted	G-2	5%	95%	Class 2		
Small/Medium Ground Mount BTM	G-2	5%	95%	Class 2		
Large Ground Mount BTM	G-2	5%	95%	Class 3		Class 2
Small/Medium Landfill	G-1	100%	0%	Class 2		
Large Landfill	G-1	100%	0%	Class 3		Class 2
Small/Medium Brownfield	G-1	100%	0%	Class 2		
Large Brownfield	G-1	100%	0%	Class 3		Class 2
Medium Ground Mount VNM	G-1	100%	0%	Class 2		
Medium MG	G-1	100%	0%	Class 2		
Large MG	G-1	100%	0%	Class 3		Class 2

Net Metering Credit Rates

- Net meter credits are equal to the following components based on the project type net metering class:

Net Metering Class	Components
Class 1	Generation + Distribution + Transition + Transmission
Class 2	Generation + Distribution + Transition + Transmission
Class 3	Generation + Transition + Transmission

- Small (<= 25 kW) projects always receive net metering (whether uncapped or capped scenario)
- In **Policy Path A** net metering credits are equal to the generation component only

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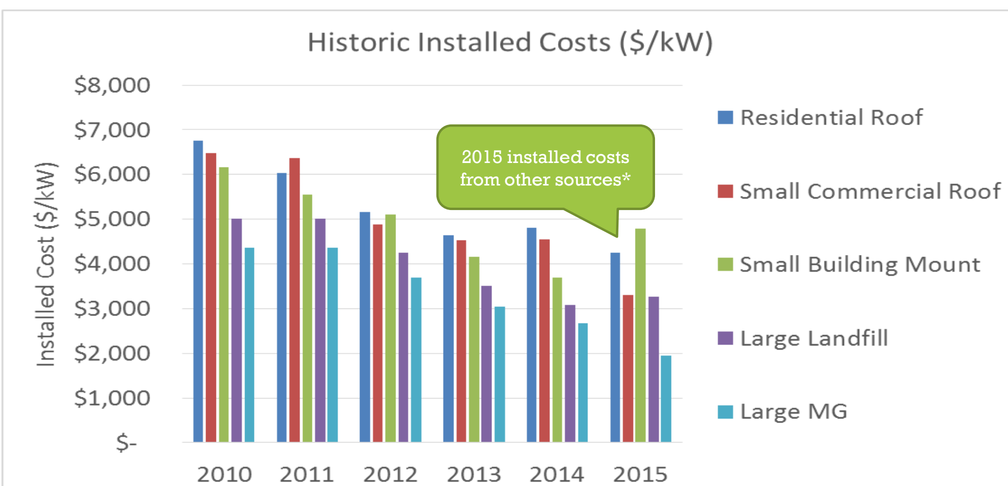
Historic Installed Costs

- Use DOER SREC-I and SREC-II SQA installed cost data to find the average annual residential installed costs and non-residential by size block for 2010 to 2014



* Discussed in detail PV System Costs section of Appendix

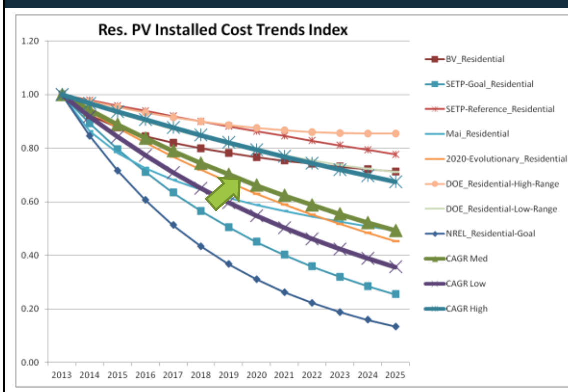
(52)

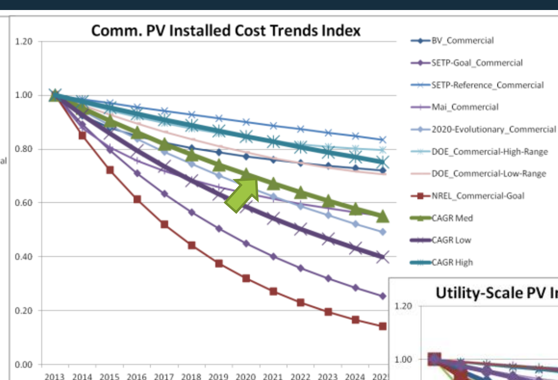
Historic:
Other PV System Costs & Rates

- O&M, customer acquisition, and interconnection costs were backcasted by extrapolating the CPI to 2010 and applying the index to 2015 costs
- Fixed costs (lease payments & PILOT/property taxes) assumed to be fixed back to 2010
- Actual 2010 to 2014 rates for each utility were used to calculate net metering and retail value of production

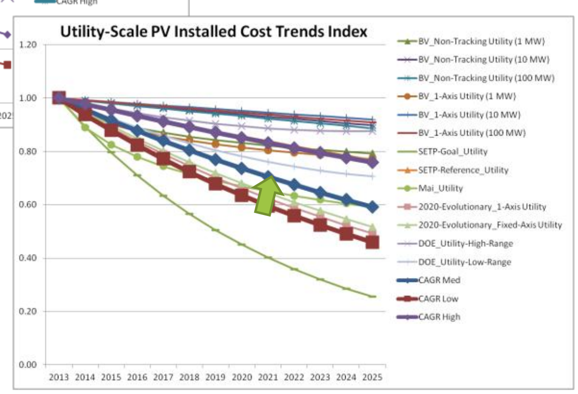
(53)

Installed Cost Forecasts: Trends





Note: No explicit adjustments made for impact of import duties; Overall impact on module price ~ 8¢/W (per SEAI), portion in effect during 2014 already embedded in forecast

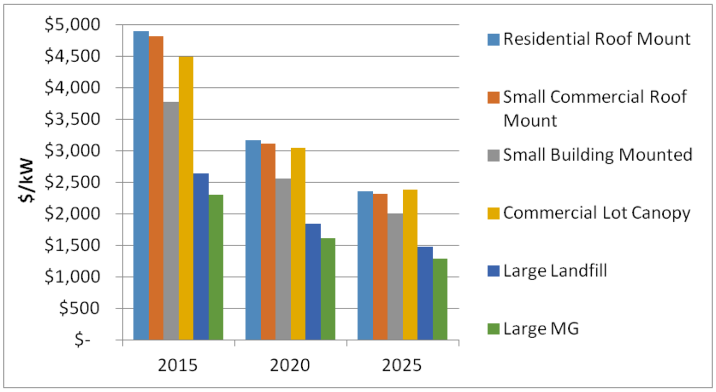


- Survey of available public sources as of late 2014 considered
- Developed trajectory as an index, applied over analysis period to applicable recent historic installed cost data
- 'Medium' used as base case for this analysis

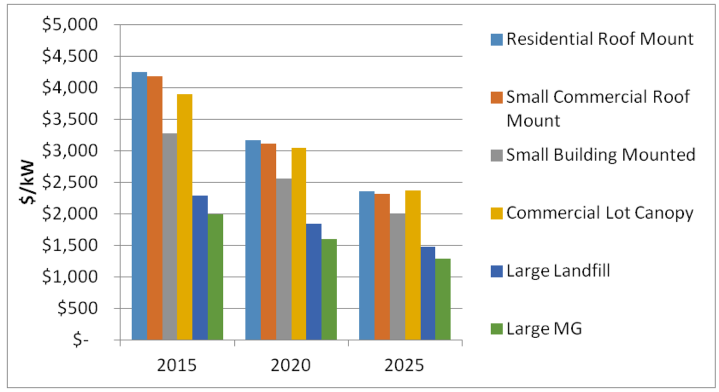
(54)

Installed Costs

Host Owned and Public Owned



Third-Party Owned



- The following blocks were also modeled: Campus Lot Canopy, Commercial Emergency Power, Community Shared Solar, On-Site LIH, VNM LIH, Medium Building Mounted, Large Building Mounted, Medium Ground Mount BTM, Large Ground Mount BTM, Small Landfill, Medium Landfill, Small Brownfield, Medium Brownfield, Large Brownfield, Medium Ground Mount VNM, Medium MG
- Blocks of high and low cost systems were also modeled (the above figures represent average cost systems)

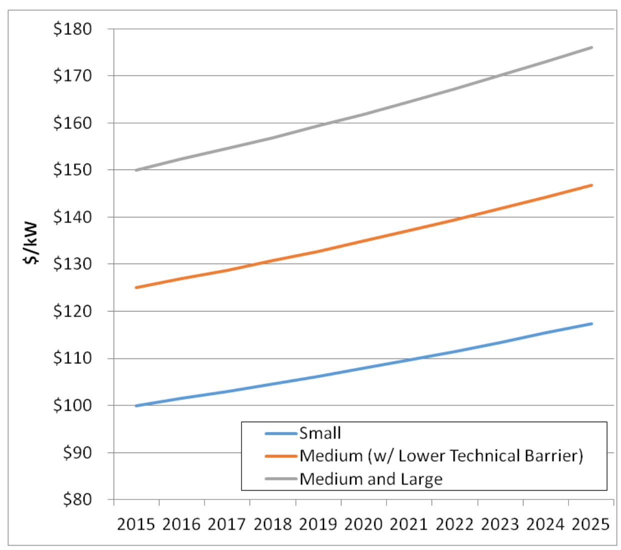
(55)

Interconnection Cost Assumptions

- Based on historical data from public sources and supplemental research
- Assumed interconnections costs vary by project size and technical barrier to interconnect
- Year 1 Interconnection Costs:

Project Size	Modeled Blocks	Year 1 Cost
Small	Residential Roof Mount, Small Commercial Roof Mount, Commercial Lot Canopy, Commercial Emergency Power, On-Site LIH, Small Building Mounted	$100/kW
Medium (with Lower Technical Barrier)	Medium Building Mounted, Medium Ground Mount BTM	$125/kW
Medium and Large	Campus Lot Canopy, Community Shared Solar, VNM LIH, Large Building Mounted, Large Ground Mount BTM, Small Landfill, Medium Landfill, Large Landfill, Small Brownfield, Medium Brownfield, Large Brownfield, Medium Ground Mount VNM, Medium MG, Large MG	$150/kW

- Escalated annually by CPI
- Assumed same interconnection costs across ownership models



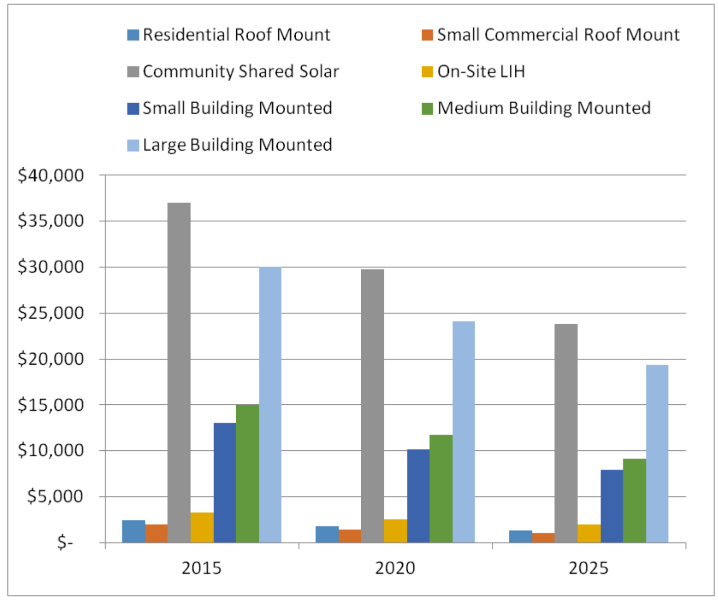
(56)

Customer Acquisition Cost Assumptions

- Based on NREL SunShot soft cost estimates
- Year 1 Customer Acquisition Costs:

Project Type	Year 1 Cost ($/kW)
Residential	$480
Small Commercial	$130
Large Commercial	$30

- Escalated annually using Installed Cost Forecast
- Only applied to third-party owned projects
- Assumed no Customer Acquisition Costs for Canopy, VNM LIH, and Ground Mounted projects



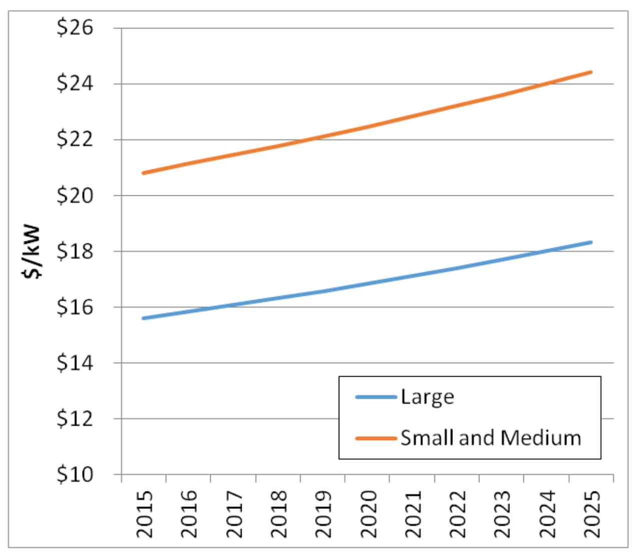
(57)

O&M Cost Assumptions

- Based on historical data from public sources and supplemental research
- Assumed O&M costs "fixed" based on system size <u>not</u> performance
- Assumed O&M costs vary by project size ➔ larger projects will have lower $/kW O&M costs
-

Project Size	Modeled Blocks	Year 1 Cost
Large	Community Shared Solar, VNM LIH, Large Ground Mount BTM, Medium Landfill, Large Landfill, Medium Brownfield, Large Brownfield, Medium MG, Large MG	$16/kW
Small and Medium	Residential Roof Mount, Small Commercial Roof Mount, Commercial Lot Canopy, Campus Lot Canopy, Commercial Emergency Power, On-Site LIH, Small Building Mounted, Medium Building Mounted, Large Building Mounted Medium Ground Mount BTM, Small Landfill, Small Brownfield, Medium Ground Mount VNM	$21/kW

- Escalated annually by CPI
- Assumed same O&M costs across ownership models



(58)

Property Tax (PILOT) and Land Lease Cost Assumptions

- Assumptions developed through market analysis and benchmarking
- PILOT Costs
  - Base Case assumed $10/kW per year, fixed over time
  - Assumed constant across all ownership models
  - Only applied to Ground Mount (incl. Landfill and Brownfield) projects
- Land Lease Costs
  - Base Case assumed $13/kW per year, fixed over time
  - Assumed constant across all ownership models
  - Not applied to Roof Mount projects

(59)

Financing Assumptions:
Related to Risk under each Policy

- For modeling, use simplified capital structure
- Debt:
  - Host & 3rd-party owned systems: on commercial terms
  - Publicly-owned projects: Based on long-term municipal bonds
- Equity
  - Initial developer/sponsor: cash + sweat equity
  - Tax equity to fully monetize tax benefits as generated
  - Where long-term contracts provide stable revenue, YieldCos emerge as another viable source of capital
- Cost & availability of capital is assumed sensitive to:
  - Contract quantity and duration
  - Type, duration & magnitude of incentive
    - Greater revenue certainty → lower cost of capital
    - Fixed PBI is likely to generate interest from more capital, at a lower cost, than a downward sloping soft price floor

- Modeling reflects:
  - Increasing competition among equity providers, including availability and applicability of YieldCo & similar investment vehicles
    - Downward pressure on cost of capital over time
  - Impact of transition from 30% to 10% ITC on capital structure and cost of capital
  - Expiration of ITC for residential host-owned
  - Impact of MA residential solar loan program for small portion of residential installations
    - Implemented as slight interest rate reduction to all residential host-owned projects
  - Considering the degree to which cost of capital advantage of fixed price PBI vs. SREC floor price shrinks as proportion of uncertain revenue shrinks
    - At the limit, if discount to floor is sufficient to finance, cost of capital advantage vanishes

(60)

Financing Assumptions:
Derivation & Application of Key Inputs

	Private, 3rd-Party	Private, Host-Owned	Public, Host-Owned
% Debt	Based on maximum sustainable debt, subject to DSCR (average = 1.35); > rev. certainty (PBI) means > leverage; Debt % also ↑ as ITC % ↓	Estimate of corporate financing structure for major capital investments	Assumed to finance 100% of cost through municipal bonds
Debt Term	Est. of commercial terms. Shorter for SREC structure, longer for PBI	Est. of corporate financing, with guarantee. Term longer for PBI than SREC	20 year bond, all market structures
Int. Rate	Term-specific risk free rate plus market-based premium; assumes volume discount compared to one-off project	Term-specific risk free rate plus market-based premium; rates higher than Private, 3rd-Party due to one-off nature	20-year municipal bond market
Loan Fee	An origination fee, paid to the lender. Set at a level which approximates the market-based premium above the base debt interest rate. For Private, Host-Owned the Loan Fee is assumed built into the term debt interest rate.		
% Equity	All remaining funds required after maximum sustainable debt; a blend of cash, tax and YieldCo equity; blend changes as ITC is reduced	Est. of corporate financing, with guarantee.	Not applicable. Projects financed 100% with municipal bonds.
AT Wtd Cost of Equity	A weighted average of cash, tax and YieldCo equity; subject to downward (competitive) pressure over time	Est. of corporate opportunity cost of other capital investments	Not applicable
WACC	= (%e * Ke) + (%d*Kd*(1-Tax Rate)) The project-specific WACC is used to convert the PBI into an equivalent EPBI (rebate).		Not applicable

(61)

Financing Assumptions: SREC
Private, 3rd-Party Ownership

kW	< 25			100			500			1,000			2,000+		
	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25
% Debt	40%	50%	50%	40%	50%	50%	40%	50%	50%	40%	55%	55%	40%	55%	55%
Debt Term	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
Int. Rate	5.50%	5.75%	6.00%	5.50%	5.75%	6.00%	5.50%	5.75%	6.00%	5.50%	5.75%	6.00%	5.50%	5.75%	6.00%
Loan Fee	2.00%	2.00%	2.25%	2.00%	2.00%	2.25%	2.00%	2.00%	2.25%	2.00%	2.00%	2.25%	2.00%	2.00%	2.25%
% Equity	60%	50%	50%	60%	50%	50%	60%	50%	50%	60%	45%	45%	60%	45%	45%
AT Wtd Cost of Equity	9.5%	8.4%	8.1%	9.5%	8.4%	8.1%	8.9%	8.4%	8.1%	8.9%	7.8%	7.6%	8.9%	7.8%	7.6%
WACC	7.0%	5.9%	5.8%	7.0%	5.9%	5.8%	6.9%	5.9%	5.8%	6.7%	5.4%	5.4%	6.7%	5.4%	5.4%

(62)

Financing Assumptions: SREC
Private Host Ownership

kW	< 25			100			500			1,000			2,000+		
	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25
% Debt	50%	50%	50%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%
Debt Term	15	15	15	12	12	12	12	12	12	12	12	12	12	12	12
Int. Rate	6.50%	6.75%	7.00%	6.50%	6.75%	7.00%	6.00%	6.25%	6.50%	6.00%	6.25%	6.50%	6.00%	6.25%	6.50%
Loan Fee	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
% Equity	50%	50%	50%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%
AT Wtd Cost of Equity	8.0%	8.0%	8.0%	12.0%	10.5%	9.0%	12.0%	10.5%	9.0%	12.0%	10.5%	9.0%	12.0%	10.5%	9.0%
WACC	5.9%	6.0%	6.1%	9.6%	8.6%	7.6%	9.5%	8.5%	7.5%	9.5%	8.5%	7.5%	9.5%	8.5%	7.5%

(63)

Financing Assumptions: SREC
Public host Ownership

kW	< 25			100			500			1,000			2,000+		
	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25
% Debt	-	-	-	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Debt Term	-	-	-	20	20	20	20	20	20	20	20	20	20	20	20
Int. Rate	-	-	-	3.5%	3.75%	4.00%	3.5%	3.75%	4.00%	3.5%	3.75%	4.00%	3.5%	3.75%	4.00%
Loan Fee	-	-	-	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%
% Equity	-	-	-	0	0	0	0	0	0	0	0	0	0	0	0
AT Wtd Cost of Equity	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WACC	-	-	-	3.5%	3.75%	4.00%	3.5%	3.75%	4.00%	3.5%	3.75%	4.00%	3.5%	3.75%	4.00%

(64)

Financing Assumptions: PBI
Private, 3rd-Party Ownership

kW	< 25			100			500			1,000			2,000+		
	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25
% Debt	50%	60%	60%	50%	60%	60%	50%	60%	60%	50%	65%	65%	50%	65%	65%
Debt Term	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
Int. Rate	6.00%	6.25%	6.50%	6.00%	6.25%	6.50%	6.00%	6.25%	6.50%	6.00%	6.25%	6.50%	6.00%	6.25%	6.50%
Loan Fee	2.00%	2.00%	2.25%	2.00%	2.00%	2.25%	2.00%	2.00%	2.25%	2.00%	2.00%	2.25%	2.00%	2.00%	2.25%
% Equity	50%	40%	40%	50%	40%	40%	50%	40%	40%	50%	35%	35%	50%	35%	35%
AT Wtd Cost of Equity	7.6%	7.1%	7.2%	7.6%	7.1%	7.2%	7.1%	6.7%	6.9%	7.3%	6.8%	7.0%	7.3%	6.8%	7.0%
WACC	5.6%	5.1%	5.2%	5.6%	5.1%	5.2%	5.3%	4.9%	5.1%	5.5%	4.8%	5.0%	5.5%	4.8%	5.0%

(65)

Financing Assumptions: PBI
Private Host Ownership

kW	< 25			100			500			1,000			2,000+		
	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25
% Debt	50%	60%	60%	50%	60%	60%	50%	60%	60%	50%	65%	65%	50%	65%	65%
Debt Term	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
Int. Rate	6.50%	6.75%	7.00%	6.50%	6.75%	7.00%	6.00%	6.25%	6.50%	6.00%	6.25%	6.50%	6.00%	6.25%	6.50%
Loan Fee	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
% Equity	50%	40%	40%	50%	40%	40%	50%	40%	40%	50%	35%	35%	50%	35%	35%
AT Wtd Cost of Equity	7.0%	7.0%	7.0%	10.0%	10.0%	9.0%	10.0%	10.0%	9.0%	10.0%	10.0%	9.0%	10.0%	10.0%	9.0%
WACC	5.4%	5.2%	5.3%	6.9%	6.4%	6.1%	6.8%	6.2%	5.9%	6.8%	5.9%	5.7%	6.8%	5.9%	5.7%

(66)

Financing Assumptions: PBI
Public host Ownership

kW	**< 25**			**100**			**500**			**1,000**			**2,000+**		
	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25
% Debt	-	-	-	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Debt Term	-	-	-	20	20	20	20	20	20	20	20	20	20	20	20
Int. Rate	-	-	-	3.5%	3.75%	4.00%	3.5%	3.75%	4.00%	3.5%	3.75%	4.00%	3.5%	3.75%	4.00%
Loan Fee	-	-	-	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%
% Equity	-	-	-	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
AT Wtd Cost of Equity	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WACC	-	-	-	3.5%	3.75%	4.00%	3.5%	3.75%	4.00%	3.5%	3.75%	4.00%	3.5%	3.75%	4.00%

F. SREC POLICY ASSUMPTIONS

SREC-I, II AND III

Modeling Extension of Current Policy: SREC-III

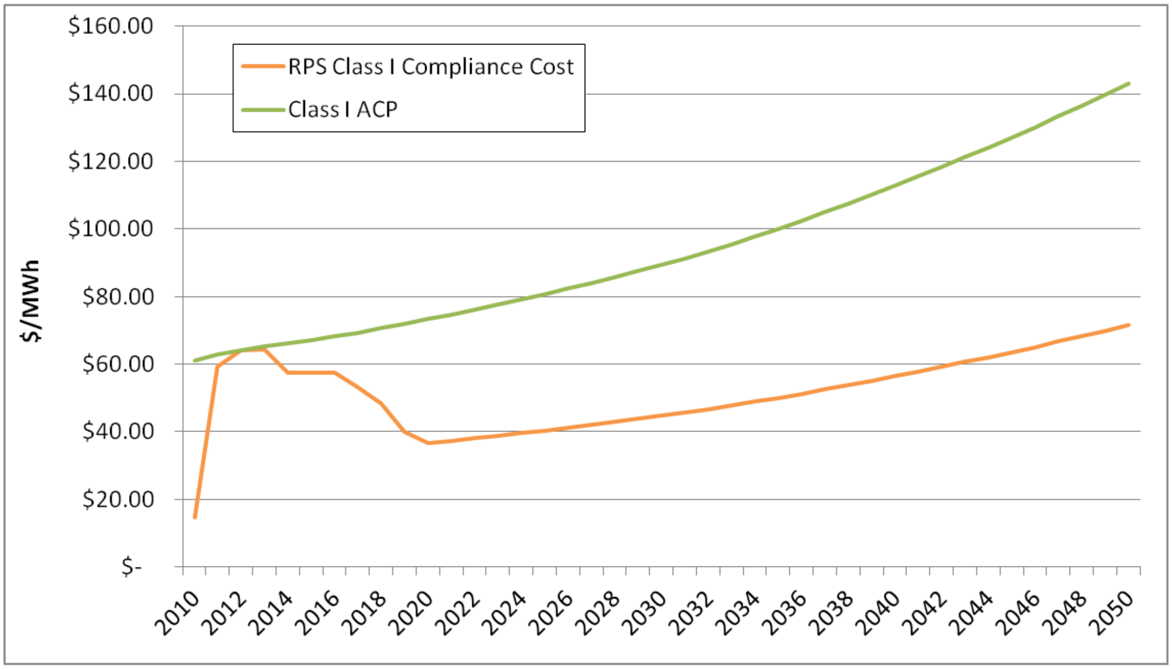
- Treated SREC-III from 1601 MW to 2500 MW dc as a separate tier, so as to not impact SREC-II expected prices and dynamics
- Extended the trend of SACP and floor price declines from those built into SREC-II policy
- Set and used annual MW targets with the objective of getting to 2500 MW by 2025, starting at the market size in last year of SREC-II with small escalator, in an analogous manner to SREC-II
- Modified SEA's proprietary Massachusetts Solar Market Study model of SREC-II with the above changes, using projected system costs and rates, to produce forecasted market buildout and prices.
- *Note: in modeling, SREC-III did not follow the targets, as sectors that were not 'managed' outstripped their targets and led to reaching 2500 MW well before 2025*

(69)

G. CLASS I RPS

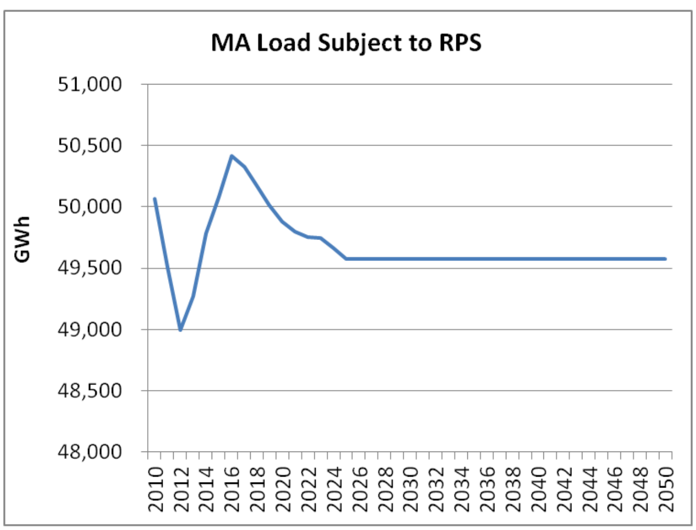
(70)

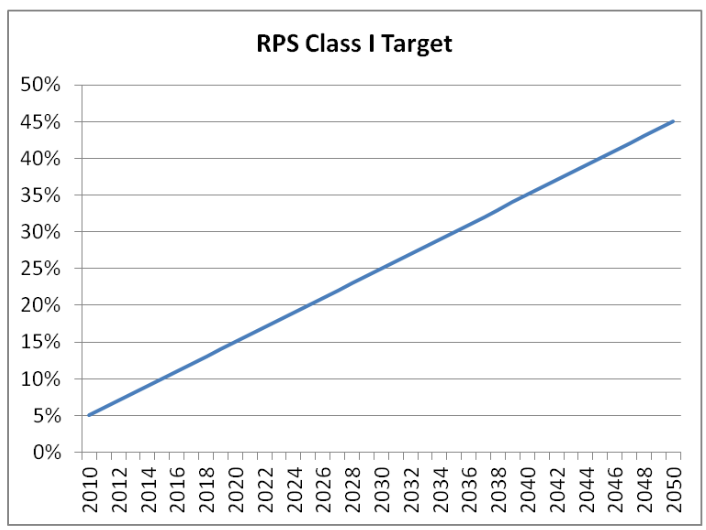
ACP and Avoided Class I RPS Compliance Costs



(71)

MA RPS Load, RPS Exemptions and Class I Targets





- RPS Exemptions = 17.27% of annual load

(72)

H. SUPPLY CURVE

APPROACH AND ASSUMPTIONS

(73)

SREC, Policy Paths A & B:
Overarching Supply Curve Granularity

- The Foundation of the Path A & B Models is a Supply Curve comprised of 612 Production Blocks
- Each Production Block is a Unique Combination of:
  - Project Type (i.e., Residential Roofmount, Medium Landfill, CSS) – 22 Types
  - Utility District (i.e., Munis, NGRID, Nstar BeCO, etc.) – 6 Districts
  - Ownership Type (i.e.. Third Party Owned, Host Owned, Public Owned) - 3 Types
  - Cost Type (High, Medium, Low Cost) - 3 Types (only 6 projects type are further disaggregated by Cost Type)
- MW Installs, MWh Production, Technical Potential, CoE, and Incentives are tracked on a quarterly basis for each of the 612 Production Blocks.

(74)

I. POLICY PATHS A & B

MODELING APPROACH AND ASSUMPTIONS

(75)

Path A & B: Aggregate Program Targets

- Overall Annual Program Targets were set to achieve 2500 MW (including SREC-I & SREC-II) by 2500, with less than 2% increase in targets annually
  - This was done to minimize installation volatility.
- For Capped Scenarios, Initial 2017 Program Aggregate Targets were set at 120 MW, increasing by 2.5 MW, to a Target of 140 MW in 2025.
- For Uncapped Scenarios, Initial 2017 Program Aggregate Targets were set at 120 MW, increasing by 2.0 MW, to a Target of 136 MW in 2025.
  - Increase was set lower than Capped because more MW were installed under SREC-II Uncapped than SREC-II Capped.
- Total Program Targets were set to exceed 2500 MW by 8.8 MW (Capped) and 13 MW (Uncapped) to Ensure 2500 MW target was Hit
  - Overbuild in final quarter of installations was pro-rated to ensure that C/B analysis only modeled costs/benefits for 2500 MW of installations.

(76)

Path A & B: Sector Specific Program Targets

- For Path A and Path B Uncapped, the following Target % were set for each Sector:
  - Sector A Small-Residential: 13.33%
  - Sector A Small-Non-Residential: 1%
  - Of the total % not devoted to Small Residential & Small Non-Residential:
    - Sector A Large: 25%
    - Sector B: 25%
    - Sector C: 25%
    - Sector D (MG): 25%
- For Path A and Path B Uncapped, the following Target % were set for each Sector:
  - Sector A Small-Residential: 13.33%
  - Sector A Small-Non-Residential: 1%
  - Of the total % not devoted to Small Residential & Small Non-Residential:
    - Sector A Large: 10%
    - Sector B: 30%
    - Sector C: 30%
    - Sector MG: 30%
- Sector A Large, Path A & Path B is set at 10% under the Capped Scenario because, as CSS and VNM LIH cannot exist in a NM Capped Scenario, the Sector lacks Resource Potential to hit a 25% Target; the 15% that was not allocated to Sector A Large was evenly distributed between Sector B, C and MG.
- Sector Specific Program Targets directly effect total installs by Path A Large Sectors, as Quarterly Base Solicitation Targets are set equal to one-fourth of Annual Targets.
- Sector Specific Program Targets affect Path A & Path B DBI/PBI & EPBI as Initially Block sizes are set at ½ of the annual 2017 target.

(77)

Path A & B: Starting Resource Potential –Utility Distribution

- Projected 2015-2016 Annual Installs were used as a Base Starting Resource Potential each Project Type (i.e., Residential Roofmount, CSS, Medium MG)
- Base Starting Resource Potential was then divided between each utility for each project type based on whether the Project was Residential, Non-Residential, Land Use Constrained, or Landfill/Brownfield:
  - Residential: Base Starting Potential was divided between each utility based on total % of Residential Customers (i.e. if Residential Roofmount project type has 10 MW of Base Starting Potential, and 10% of Residential customers are in Utility X, Utility X's -Residential Roofmount has 1MW of Resource Potential)
  - Non-Residential: Base Starting Potential was divided between each utility based on total % of Non-Residential Customers
  - Land-Use Constrained: Base Starting Potential was divided between each utility based on a weighting of open space potential in the utility district (2x Weight), and % Non-Residential Customers in each utility (1x Weight).
    - Open Space Potential is an analytically derived metric based on: 1.) Total Acreage in each Utility; and 2.) Population density in each utility.
  - Landfill/Brownfield: Base Starting Potential was divided between each utility based on a weighting of open space potential in the utility district (1x Weight), and % Non-Residential Customers in each utility (2x Weight).

(78)

Path A & B: Starting Resource Potential –Ownership/Cost Distribution

- After dividing Resource Potential between each utility, Resource Potential was then divided between project ownership types (Host Owned, Third Party Owned, Public Owned) based on 2015-2016 SREC-II projections.
  - E.G., Residential Roofmount had roughly a 51-49% relative split between Third Party Owned and Host Owned Projects, thus 51% of technical potential was distributed to 3PO, and 49% to HO projects.
- Finally, after dividing Resource Potential between utilities and ownership type, Resource potential was further divided based on whether the Project Type was segmented by High/Medium/Low Cost.
  - 50% to Medium Cost
  - 25% to Low Cost
  - 25% to High Cost
  - If a project type was not segmented by Cost, naturally no division occurred.

(79)

Path A & B: Ongoing Resource Potential & Growth Rates

- Production Block Resource Potential in each Sector grow at a fixed rate annually, which is equal to MW installed in the previous year multiplied by a Growth Factor.
  - e.g., If a Production Block installs 20 MW in a year, and the Growth factor is 105%, the Production Block will have a technical potential of 21 MW in the subsequent year.
  - Growth Rates set conservatively at 105%-116% for all Sectors.
- Growth/Resource Potential forecasted on an annual basis; as the Model runs quarterly, annual Resource Potential was divided by four (4) to establish quarterly potential.
- Resurrection Rates: In the event a modeled Production Block installs no MW in a year, but Cost ofentry declines to such a degree that said Block could install in subsequent year, Resource Potential is set at ½ of Starting Potential (i.e., Resource Potential in 2017) for installs in the subsequent.

(80)

Path A Large: Competitive Solicitation, Modeling Assumptions

- Solicitations modeled to take place every Quarter.
- Base Quarterly Solicitation Targets equal to ¼ of Annual Sector Targets.
- "Price is Right" Type Solicitation Modeling: Each Quarter, Production Blocks are modeled to be successful until the cumulative MW including the next potential successful marginal Production Block's Resource Capacity is greater than Solicitation Targets (i.e. closest without going over).
  - This means that each solicitation, some % of the MW Target is not fulfilled (unless by chance, Cumulative MW installed for the Marginal Production Block exactly equals the Target);
  - The % of MW target not hit is rolled to the next solicitation as a Remainder.
- Further, a **10% Failure Rate** (i.e. 10% of selected projects fail to reach commercial operation) is assumed; all successful Production Blocks are prorated by 10%, and "Failed MW" are rolled into a solicitation exactly one year in the future.
- Quarterly Targets are equal to: Base Quarterly Target + Remainder & Failed MW carried to that solicitation.
- The combination of Remainder MW and Failure Rates means that MW solicited in each quarterly solicitation increase at a higher rate than initially set Annual Target percentages, and, likewise, that less MW is installed in early years than targeted.
- No Failure Rate assumed in 2025, so that the Model can hit Program Targets.

(81)

Path A Large: Competitive Solicitation, Incentive Assumptions

- Assumed that Production Blocks cannot bid below the value of Electric/NM Rates received from their utility.
- Production Block modeled to bid a Combined Incentive Bid (equal to their needed PBI Incentive + Levelized 15-yr Value of Electric/NM Rates).
- It is assumed that Bidders will strategically bid in such a way as to converge their bids with the marginal bid; thus, in calculating incentives for C/B Analysis, the **calculated Combined Incentive Bid for a successful bidder is equal to the average of the Marginal Bid and the bidders Cost of Entry Bid**.
- PBI Incentive are calculated for C/B analysis by netting out the 15-yr Levelized Value of Electric/NM Rates from the Combined Incentive Bid.

(82)

Path A & B: DBI/PBI, Modeling Assumptions

- Modeled on a Quarterly basis;
- Initial DBI Block sizes set equal to ½ of 2017 Annual Targets;
- All Production Blocks across a Sector compete for the same DBI/PBI Block (however, DBI/PBI incentives vary by utility)
- Model only allows at most two (2) DBI Blocks to fill per quarter;
  - Therefore, total MW that can be installed in a quarter is equal to: total MW remaining in a DBI Block that was partially filled in the previous quarter + the DBI Block Size.
- Model functions by looking at the PBI Incentive Level that each utility is offering, and allowing a Production Block to install in that quarter if PBI is greater than Cost of Entry.

(83)

Path A& B: DBI/PBI, Incentive Assumptions

- Initial DBI/PBI Incentives are set for utility in each Sector, in reference to an Initial Benchmark "Combined Incentive."
- Initial Combined Incentives are calculated by:
  - Selecting a Benchmark Production Block (e.g., Commercial Solar Canopy-NGIRD-Third Party Owned);
  - Determining the Levelized 15-yr Value of Electric/NM Rates for the Benchmark Production Block;
  - Adding this Levelized 15-yr Rate Value to an Optimized DBI/PBI Starting $/MWh incentive (Optimization process discussed in subsequent slide);
- DBI/PBI incentives are then set for each utility by netting out the Levelized 15-yr Rate Value specific to the comparable Benchmark Production Block in that utility from the Combined Incentive.
  - E.g., if the Benchmark Production Block is Commercial Solar Canopy-NGIRD-Third Party Owned, the Levelized 15-yr Rate Value for Commercial Solar Canopy-WMECO-Third Party Owned is netted from the Combined Incentive to determine the initial WMECO DBI/PBI .
- All Utility DBI/PBI incentives in a sector decline by the same specific fixed $/MWh rate:
  - Fixed $/MWh decline used because a % based decline will never "zero-out"
  - Further, analysis showed that program volatility can be better managed with $/MWh than % based DBI/PBI declines.

(84)

Path B: DBI/EPBI Modeling/Incentive Assumptions

- Path B DBI/EPBI was modeled using exactly the same process as DBI/PBI, with the exception that DBI/PBI and Initial Combined Incentives were calculated in $/kW rather than $/MWh; **and**
- The Levelized 15-yr Value of Electric/NM Rates was calculated by discounting the 15-year calculated PBI using the Production Block's weighted average cost of capital (WACC) as a discount rate, rather than Target Equity IRR.

(85)

Path A & B: DBI/PBI & EPBI Incentive Optimization Process

- **Setting DBI/PBI Incentives involves a balancing of several factors:** 2017 install Rates, and level of industry constriction versus 2016; level, constant growth versus volatile growth; setting minimum incentive levels to achieve 2025 targets at lowest cost.
- Because of this, Initial DBI/PBI/EPBI incentives (and decline rates) were set to meet the following policy objectives as closely as possible:
  - 2017 annual installs in each sector being as close to 2017 targets as possible;
  - Sectors hitting their targets (and the Program Hitting 2500 MW) as close to QT. 4, 2025 as possible;
  - Minimize volatility in annual installs from 2017-2025;
  - Incentive levels as low as possible, while still meeting the above objectives, to minimize costs;
- There is more than one solution set (i.e. Initial DBI/PBI or EPBI Incentive Levels **and** $/MWh or $/kW decline rate) that can meet the above parameters;
  - However, more than 100 combinations were tested for each Sector (under each Policy Path and Scenario), and any parallel solution set would be, at best, only marginally better.
- As Path A, Large does not use an open-enrollment system, and incentives are set by bidding rather than centrally planned, no optimization process was necessary.

(86)

J. CALCULATION OF OTHER COST & BENEFIT COMPONENTS

MISC. OTHER ASSUMPTIONS

(87)

'Parametric Analysis' Components

- Where data availability is limited or estimate would require extensive analysis infeasible within scope/timeline, we will make a parametric assumption
  - Example: "x% of cost item retained in-state"
- Consulting team will make an 'anchor' estimate
  - Based on brief literature, review, TF member input, or team judgment.
- When parametric assumption is applied to a model result (i.e. in $ or $/yr), a 10% sensitivity is possible.
  - Example: if anchor parameter is 50%, result will also be calculated as 60%
  - The sensitivity to changes of 10% from the key assumption is easily scaled to give magnitude of sensitivity over a broad range
- When parametric assumption is applied as an input to a complex model, analysis of sensitivities are beyond scope.

(88)

Parametric Values Assumptions:
Base Case Values used for All Presented Results; Sensitivity #s used for Sensitivity Analyses

		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%*	% of load on feeders with growth
Avoided Transmission Investment - Local	CB6.2	B	Base	80%	80.0%	90%*	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%*	% of load on feeders with growth
Avoided Distribution Investment	CB6.3	B	Base	50%	50.0%	60%*	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%*	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

(89)

System Installed Costs CB1.1

System Installed Costs Retained in State (Inputs)

	Residential			Small Commercial (Roof-top)			Small Commercial (Ground-mount)		
	Cost ($/kW)	% of Total Cost*	% Local Share	Cost ($/kW)	% of Total Cost*	% Local Share	Cost ($/kW)	% of Total Cost*	% Local Share
System Installation Costs									
Installation Costs									
Materials & Equipment									
Mounting (rails, clamps, fittings, etc.)	$168.10	3.4%	50%	$165.52	3.4%	40%	$90.71	3.4%	25%
Modules	$1,637.13	33.4%	0%	$1,612.05	33.4%	0%	$883.43	33.4%	0%
Electrical (wire, connectors, breakers, etc.)	$108.16	2.2%	50%	$106.51	2.2%	40%	$58.37	2.2%	25%
Inverter	$243.37	5.0%	50%	$239.64	5.0%	40%	$131.33	5.0%	25%
Labor									
Installation	$350.68	7.2%	95%	$345.30	7.2%	90%	$189.23	7.2%	70%
Other Costs									
Permitting	$651.64	13.3%	95%	$641.66	13.3%	95%	$351.64	13.3%	95%
Other Costs	$293.02	6.0%	63%	$288.53	6.0%	56%	$158.12	6.0%	56%
Business Overhead	$1,446.19	29.5%	63%	$1,424.04	29.5%	56%	$780.40	29.5%	56%
Sales Tax (Materials & Equipment Purchases)	$0.00	0%	0%	$0.00	0%	0%	$0.00	0%	0%
Total	$4,896.00	100.0%	47%	$4,821.00	100.0%	43%	$2,642.00	100.0%	40%

- % of Total Cost comes from NREL JEDI model default data for Massachusetts
- % Local Share developed from DOER 2013 Task 4 Consultant Report: "*Comparative Regional Economic Impacts of Solar Ownership/Financing Alternatives*" and supplemental research
- Used approx. weighted average of 42%. Based on analysis of annual weighted avg. blend of res, commercial rooftop and ground mount over time. #s were not highly sensitive to evolving blend, varying between 41% and 43%.

(90)

Ongoing O&M + Insurance Costs | CB1.2

System O&M Costs Retained in State (Inputs)

	Residential			Small Commercial (Roof-top)			Small Commercial (Ground-mount)		
	Cost ($/kW)	% of Total Cost*	% Local Share	Cost ($/kW)	% of Total Cost*	% Local Share	Cost ($/kW)	% of Total Cost*	% Local Share
Ongoing O&M Costs									
Labor									
Technicians	$11.46	54.6%	100%	$11.46	54.6%	90%	$8.73	54.6%	90%
Materials and Services									
Materials & Equipment	$9.55	45.5%	50%	$9.55	45.5%	40%	$7.28	45.5%	25%
Services	$0.00	0.0%	100%	$0.00	0.0%	56%	$0.00	0.0%	58%
Sales Tax (Materials & Equipment Purchases)	$0.00	0%	0%	$0.00	0%	0%	$0.00	0%	0%
Total	$21.00	100.0%	77%	$21.00	100.0%	67%	$16.00	100.0%	60%

- % of Total Cost comes from NREL JEDI model default data for Massachusetts
- % Local Share developed from DOER 2013 Task 4 Consultant Report: "*Comparative Regional Economic Impacts of Solar Ownership/Financing Alternatives*" and supplemental research
- Used 64%. Based on analysis of annual weighted avg. blend of res, commercial rooftop and ground mount over time. #s were not highly sensitive to evolving blend, varying between 63% and 68%

(91)

Wholesale Market Price Impacts - Energy | CB5.1

Wholesale Market Price Impacts

- Wholesale energy market price effects are not in perpetuity
  - Effect of installation in year X assumed to dissipate based on energy DRIPE 2014 dissipation schedule from AESC 2013
- Wholesale energy market price effects only impact purchases from spot market or short-term transactions influenced by spot market. Energy transacted under multi-year energy hedges are not impacted
  - Effect of installation in year X assumed to phase in according to 2014 energy DRIPE hedged energy schedule from AESC 2013

Table 4. Energy Market Effect Adjustments

Production Year(s)	Dissipation %	Load Subject to Solar Market Effects
1	13%	18%
2	18%	72%
3	21%	81%
4	28%	90%
5	34%	90%
6	47%	90%
7	59%	91%
8	70%	91%
9	81%	91%
10	91%	92%
11-end of study period	100%	92%

(92)

Solar Policy Incr. Admin. & Transaction Costs | CB2.4

Estimating EDC Incremental Admin Costs for Policy Paths A & B

- Assumed all EDC labor costs were incremental (whether or not EDC would have sought additional rate recover for these types of costs as core vs. incremental staff in the past)
- Cost estimates by SEA based SEA interpretation of interviews with EDC procurement staff
  - Results not reviewed or endorsed by EDCs
- Categories:
  - One-tome Setup Costs, New Policies (Staffing: EDC staff, legal); systems; tariff design, approvals, training)
    - Small: 2 FTEs, split 75% in 2016, 25% in 2017
    - Large: 2 FTEs, split 75% in 2016, 25% in 2017
    - Same for Paths A & B
  - Solicitation Costs (thru 2025) – Policy Path A (large) only
    - Including core staff, assume 25% of $500K. Assume this is per solicitation round based on LREC/ZREC 1 round/yr. If move to 3 rounds per year, assume some scale economies ==> assume 2.5x the cost of one solicitation
    - Escalate at 4%/yr
  - Ongoing Admin. Costs from 2017 on (Ongoing admin costs (meter reading, hand holding, accounting, payments, recovery filings… (applying from startup to completion, thru 2050)
    - Assume 1.25 FTEs initially for small and 2 for large
    - Costs assumed to escalate annually by 20% of increase in target procurement volume to reflect some increase in labor costs with increased transcaction volume but strong scale economies
  - Transaction Costs for reselling RECs on a $/MWh (Broker Fees Associated with the Sale of RECs if performed through a broker)
    - Assume $1/MWh, applying to 50% of all distribution load (reflecting 1 – today's basic service %)
    - Note: Under SREC, Assume EDCs only purchase for own needs, don't need to resell; SREC Policy 'transactional friction" modeled as part of SREC market mdoel as $2.50 per SREC purchased by LSEs outside of small quantity of direct hedge transactions entered into with generators up-front to support financing
    - Note: corresponding market participant costs for SREC policies embedded in SREC market model, captured there
- Utility staff Average FTE cost used in model: $162,500 fully-loaded, based on input from 2 EDCs

(93)

Solar Policy Incr. Admin. & Transaction Costs | CB2.4

Policy Path A additional developer overhead due to the need to sell both winning and losing bids:
Cust Aq. Cost * (sales/contract under solicitation – sale/contract under open program)

Commercial PV Customer Acquisition Cost ($/kW) (from NREL studies)			
Project Type	Med/Small	Med/Small	Large
Project Size	Not Specified	<250 kW	>250kW
Note	2010 Median	2012 Median	2012 Median
System Design	$0.10	$0.04	$0.01
Marketing/Advertising	$0.01	-	-
Other	$0.08	$0.09	$0.02
Total	$0.19	$0.13	$0.03

Assume $0.05/W as approx. fleet wtd. Avg.

*

Assume 2.5 bids/winning bid

➔ $0.05/W*(2.5-1) = $0.075/W

		# of Projects								
		Round 1			Round 2			Round 3		
		Total	Accepted	Ratio	Total	Accepted	Ratio	Total	Accepted	Ratio
Large ZREC	CL&P	140	21	6.67	52	19	2.74	78	32	2.44
	UI	22	6	3.67	12	4	3.00	8	8	1.00
	Total	162	27	6.00	64	23	2.78	86	40	2.15
Medium ZREC	CL&P	113	47	2.40	157	70	2.24	113	95	1.19
	UI	37	13	2.85	35	24	1.46	50	27	1.85
	Total	150	60	2.50	192	94	2.04	163	122	1.34
		Capacity (MW)								
		Round 1			Round 2			Round 3		
		Total	Accepted	Ratio	Total	Accepted	Ratio	Total	Accepted	Ratio
Large ZREC	CL&P	94.3	12.2	7.73	34.2	12.2	2.80	65.3	27.6	2.37
	UI	12.1	2.6	4.65	7.2	2.4	3.00	5.9	5.9	1.00
	Total	106.4	14.8	7.19	41.4	14.6	2.84	71.2	33.5	2.13
Medium ZREC	CL&P	21.5	8.8	2.44	30.2	14.2	2.13	24.5	18.1	1.35
	UI	7.1	2.5	2.84	6.4	4.4	1.45	9.7	5.1	1.90
	Total	28.6	11.3	2.53	36.6	18.6	1.97	34.2	23.2	1.47

MA Income Taxes	CB1.6.b	Federal Income Taxes	CB1.7b

Estimate of Taxable Discounts & Lease Revenue

Used for estimating income tax impact of these benefits on NOPs

% of Discount Payments Assumed Taxable

Scenario	2015	2020	2025
SREC Capped-1600	35%	80%	80%
SREC Uncapped-1600	35%	80%	80%
SREC Capped-2500	35%	80%	80%
Policy A Capped-1600	35%	80%	80%
Policy A Capped-2500	35%	80%	80%
Policy A Uncapped-1600	35%	80%	80%
Policy A Uncapped-2500	35%	35%	35%
Policy B Capped-1600	35%	80%	80%
Policy B Capped-2500	35%	80%	80%
Policy B Uncapped-1600	35%	80%	80%
Policy B Uncapped-2500	35%	35%	35%

% of Lease Payments Assumed Taxable

Scenario	2015	2020	2025
SREC Capped-1600	75%	80%	80%
SREC Uncapped-1600	75%	80%	80%
SREC Capped-2500	75%	80%	80%
Policy A Capped-1600	75%	80%	80%
Policy A Capped-2500	75%	80%	80%
Policy A Uncapped-1600	75%	80%	80%
Policy A Uncapped-2500	75%	75%	75%
Policy B Capped-1600	75%	80%	80%
Policy B Capped-2500	75%	80%	80%
Policy B Uncapped-1600	75%	80%	80%
Policy B Uncapped-2500	75%	75%	75%

Assumptions made based on SEA side-analysis to estimate evolving mix of taxable and non-taxable lease and PPA/NMC off-takers

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Task Report 3: Appendix B

Appendix B:

Task 3 - Analysis of Costs and Benefits: Detailed Cost and Benefit Result Tables

Massachusetts Net Metering and Solar Task Force

PEREGRINE ENERGY GROUP

Sustainable Energy Advantage, LLC

MEISTER CONSULTANTS GROUP

La Capra Associates

NOP 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
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

		2500 MW		1600 MW	
C/B Component ↓	CB Code	NPV Costs (Million $)	NPV$/MWh Costs	NPV Costs (Million $)	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**

(2)

NOP Costs and Benefits – SREC Uncapped

Benefits

C/B Component ↓	CB Code	1600 MW NPV Benefits (Million $)	1600 MW NPV $/MWh Benefits
Lease Payments	CB1.3	$ 223.4	$ 5.1
PILOTs / Property Taxes	CB1.4	$ 160.7	$ 3.7
Generation Value of On-site Generation	CB3.1	$ 94.1	$ 2.2
Transmission Value of On-site Generation	CB3.2	$ 15.7	$ 0.4
Distribution Value of On-site Generation	CB3.3	$ 37.9	$ 0.9
Other Retail Bill Components (Trans., EE, RE)	CB3.4	$ 6.6	$ 0.2
Offsetting On-site Usage	CB4.1	$ 9.1	$ 0.2
Virtual NM	CB4.2	$ 525.0	$ 12.1
Total		**$ 1,072.5**	**$ 24.6**

Costs

C/B Component ↓	CB Code	1600 MW NPV Costs (Million $)	1600 MW NPV $/MWh Costs
MA Income Taxes	CB1.6.b	$ 53.0	$ 1.2
Federal Income Taxes	CB1.7b	$ 231.9	$ 5.3
Total		**$ 284.9**	**$ 6.5**

(3)

NOP Costs and Benefits – Policy A 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	$ 304.3	$ 4.3	$ 222.7	$ 5.0
PILOTs / Property Taxes	CB1.4	$ 204.3	$ 2.9	$ 156.8	$ 3.5
Generation Value of On-site Generation	CB3.1	$ 167.8	$ 2.4	$ 104.8	$ 2.3
Transmission Value of On-site Generation	CB3.2	$ 24.9	$ 0.4	$ 17.3	$ 0.4
Distribution Value of On-site Generation	CB3.3	$ 63.9	$ 0.9	$ 42.3	$ 0.9
Other Retail Bill Components (Trans., EE, RE)	CB3.4	$ 10.8	$ 0.2	$ 7.3	$ 0.2
Offsetting On-site Usage	CB4.1	$ 10.2	$ 0.1	$ 9.0	$ 0.2
Virtual NM	CB4.2	$ 453.1	$ 6.4	$ 453.1	$ 10.1
Total		**$ 1,239.3**	**$ 17.6**	**$ 1,013.3**	**$ 22.7**

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	$ 63.3	$ 0.9	$ 51.9	$ 1.2
Federal Income Taxes	CB1.7b	$ 277.0	$ 3.9	$ 227.1	$ 5.1
Total		**$ 340.4**	**$ 4.8**	**$ 279.0**	**$ 6.2**

(4)

NOP Costs and Benefits – Policy A Uncapped

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	$ 203.8	$ 2.9	$ 198.1	$ 4.4
PILOTs / Property Taxes	CB1.4	$ 146.8	$ 2.1	$ 142.9	$ 3.2
Generation Value of On-site Generation	CB3.1	$ 134.7	$ 1.9	$ 97.4	$ 2.2
Transmission Value of On-site Generation	CB3.2	$ 19.8	$ 0.3	$ 16.2	$ 0.4
Distribution Value of On-site Generation	CB3.3	$ 48.0	$ 0.7	$ 39.3	$ 0.9
Other Retail Bill Components (Trans., EE, RE)	CB3.4	$ 9.1	$ 0.1	$ 6.8	$ 0.2
Offsetting On-site Usage	CB4.1	$ 11.9	$ 0.2	$ 9.3	$ 0.2
Virtual NM	CB4.2	$ 659.1	$ 9.4	$ 497.8	$ 11.1
Total		**$ 1,233.2**	**$ 17.5**	**$ 1,008.0**	**$ 22.6**

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	$ 36.6	$ 0.5	$ 49.0	$ 1.1
Federal Income Taxes	CB1.7b	$ 160.2	$ 2.3	$ 214.2	$ 4.8
Total		**$ 196.8**	**$ 2.8**	**$ 263.2**	**$ 5.9**

(5)

NOP Costs and Benefits – Policy B 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	$ 299.1	$ 4.2	$ 222.4	$ 5.0
PILOTs / Property Taxes	CB1.4	$ 204.3	$ 2.9	$ 157.5	$ 3.5
Generation Value of On-site Generation	CB3.1	$ 160.1	$ 2.3	$ 102.2	$ 2.3
Transmission Value of On-site Generation	CB3.2	$ 25.9	$ 0.4	$ 17.0	$ 0.4
Distribution Value of On-site Generation	CB3.3	$ 66.6	$ 0.9	$ 41.9	$ 0.9
Other Retail Bill Components (Trans., EE, RE)	CB3.4	$ 10.3	$ 0.1	$ 7.1	$ 0.2
Offsetting On-site Usage	CB4.1	$ 11.8	$ 0.2	$ 9.2	$ 0.2
Virtual NM	CB4.2	$ 453.1	$ 6.4	$ 453.1	$ 10.1
Total		**$ 1,231.0**	**$ 17.5**	**$ 1,010.3**	**$ 22.6**

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	$ 62.8	$ 0.9	$ 51.7	$ 1.2
Federal Income Taxes	CB1.7b	$ 274.7	$ 3.9	$ 226.0	$ 5.1
Total		**$ 337.5**	**$ 4.8**	**$ 277.7**	**$ 6.2**

(6)

NOP Costs and Benefits – Policy B Uncapped

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	$ 299.1	$ 4.3	$ 222.0	$ 5.0
PILOTs / Property Taxes	CB1.4	$ 213.2	$ 3.0	$ 159.5	$ 3.6
Generation Value of On-site Generation	CB3.1	$ 132.3	$ 1.9	$ 97.1	$ 2.2
Transmission Value of On-site Generation	CB3.2	$ 21.6	$ 0.3	$ 16.1	$ 0.4
Distribution Value of On-site Generation	CB3.3	$ 52.3	$ 0.7	$ 39.2	$ 0.9
Other Retail Bill Components (Trans., EE, RE)	CB3.4	$ 8.8	$ 0.1	$ 6.8	$ 0.2
Offsetting On-site Usage	CB4.1	$ 13.7	$ 0.2	$ 9.6	$ 0.2
Virtual NM	CB4.2	$ 775.5	$ 11.0	$ 520.4	$ 11.7
Total		**$ 1,516.6**	**$ 21.6**	**$ 1,070.8**	**$ 24.0**

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
MA Income Taxes	CB1.6.b	$ 45.7	$ 0.7	$ 53.0	$ 1.2
Federal Income Taxes	CB1.7b	$ 199.9	$ 2.8	$ 232.0	$ 5.2
Total		**$ 245.7**	**$ 3.5**	**$ 285.0**	**$ 6.4**

(7)

CG 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
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

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
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**

(8)

CG Costs and Benefits – SREC Uncapped

Benefits

C/B Component ↓	CB Code	1600 MW NPV Benefits (Million $)	1600 MW NPV $/MWh Benefits
ROI (Aggregate Return to Debt & Equity)	CB1.5	$ -	$ -
MA Residential RE Tax Credit	CB1.6.a	$ 42.4	$ 1.0
Federal Incentives (ITC)	CB1.7a	$ 1,258.1	$ 28.9
Direct Incentives (e.g., SRECs)	CB2.1	$ 3,526.7	$ 81.0
Generation Value of On-site Generation	CB3.1	$ 766.0	$ 17.6
Transmission Value of On-site Generation	CB3.2	$ 130.9	$ 3.0
Distribution Value of On-site Generation	CB3.3	$ 320.6	$ 7.4
Other Retail Bill Components (Trans., EE, RE)	CB3.4	$ 51.3	$ 1.2
Offsetting On-site Usage	CB4.1	$ 103.1	$ 2.4
Virtual NM	CB4.2	$ 2,891.5	$ 66.4
Wholesale Market Sales	CB4.3	$ -	$ -
Avoided Generation Capacity Costs	CB5.3	$ 77.9	$ 1.8
Total		**$ 9,168.5**	**$ 210.6**

Costs

C/B Component ↓	CB Code	1600 MW NPV Costs (Million $)	1600 MW NPV $/MWh Costs
System Installed Costs	CB1.1	$ 5,136.5	$ 118.0
Ongoing O&M + Insurance Costs	CB1.2	$ 986.7	$ 22.7
Lease Payments	CB1.3	$ 223.4	$ 5.1
PILOTs / Property Taxes	CB1.4	$ 160.7	$ 3.7
MA Income Taxes	CB1.6.b	$ 23.0	$ 0.5
Federal Income Taxes	CB1.7b	$ 100.8	$ 2.3
Solar Policy Incr. Admin. & Transaction Costs	CB2.4	$ -	$ -
Total		**$ 6,631.2**	**$ 152.3**

(9)

CG Costs and Benefits – Policy A 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
ROI (Aggregate Return to Debt & Equity)	CB1.5	$ -	$ -	$ -	$ -
MA Residential RE Tax Credit	CB1.6.a	$ 59.8	$ 0.8	$ 43.8	$ 1.0
Federal Incentives (ITC)	CB1.7a	$ 1,335.4	$ 19.0	$ 1,251.3	$ 28.0
Direct Incentives (e.g., SRECs)	CB2.1	$ 4,342.9	$ 61.7	$ 3,592.3	$ 80.4
Generation Value of On-site Generation	CB3.1	$ 1,462.9	$ 20.8	$ 836.4	$ 18.7
Transmission Value of On-site Generation	CB3.2	$ 213.3	$ 3.0	$ 138.6	$ 3.1
Distribution Value of On-site Generation	CB3.3	$ 551.3	$ 7.8	$ 343.0	$ 7.7
Other Retail Bill Components (Trans., EE, RE)	CB3.4	$ 90.3	$ 1.3	$ 55.9	$ 1.3
Offsetting On-site Usage	CB4.1	$ 114.2	$ 1.6	$ 94.9	$ 2.1
Virtual NM	CB4.2	$ 2,409.7	$ 34.2	$ 2,409.7	$ 53.9
Wholesale Market Sales	CB4.3	$ 841.1	$ 11.9	$ 226.7	$ 5.1
Avoided Generation Capacity Costs	CB5.3	$ 119.0	$ 1.7	$ 77.8	$ 1.7
Total		**$ 11,540.0**	**$ 163.8**	**$ 9,070.2**	**$ 202.9**

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
System Installed Costs	CB1.1	$ 6,267.7	$ 89.0	$ 5,094.3	$ 114.0
Ongoing O&M + Insurance Costs	CB1.2	$ 1,270.7	$ 18.0	$ 949.5	$ 21.2
Lease Payments	CB1.3	$ 304.3	$ 4.3	$ 222.7	$ 5.0
PILOTs / Property Taxes	CB1.4	$ 204.3	$ 2.9	$ 156.8	$ 3.5
MA Income Taxes	CB1.6.b	$ 222.2	$ 3.2	$ 123.1	$ 2.8
Federal Income Taxes	CB1.7b	$ 972.0	$ 13.8	$ 538.5	$ 12.0
Solar Policy Incr. Admin. & Transaction Costs	CB2.4	$ 71.2	$ 1.0	$ 17.9	$ 0.4
Total		**$ 9,312.3**	**$ 132.2**	**$ 7,102.7**	**$ 158.9**

(10)

CG Costs and Benefits – Policy A Uncapped

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
ROI (Aggregate Return to Debt & Equity)	CB1.5	$ -	$ -	$ -	$ -
MA Residential RE Tax Credit	CB1.6.a	$ 58.8	$ 0.8	$ 43.2	$ 1.0
Federal Incentives (ITC)	CB1.7a	$ 1,337.1	$ 19.0	$ 1,256.4	$ 28.1
Direct Incentives (e.g., SRECs)	CB2.1	$ 3,830.3	$ 54.5	$ 3,446.4	$ 77.2
Generation Value of On-site Generation	CB3.1	$ 1,258.6	$ 17.9	$ 786.3	$ 17.6
Transmission Value of On-site Generation	CB3.2	$ 182.1	$ 2.6	$ 131.8	$ 3.0
Distribution Value of On-site Generation	CB3.3	$ 452.2	$ 6.4	$ 321.1	$ 7.2
Other Retail Bill Components (Trans., EE, RE)	CB3.4	$ 81.2	$ 1.2	$ 53.2	$ 1.2
Offsetting On-site Usage	CB4.1	$ 133.3	$ 1.9	$ 99.0	$ 2.2
Virtual NM	CB4.2	$ 3,513.1	$ 50.0	$ 2,687.3	$ 60.2
Wholesale Market Sales	CB4.3	$ -	$ -	$ -	$ -
Avoided Generation Capacity Costs	CB5.3	$ 119.2	$ 1.7	$ 77.8	$ 1.7
Total		**$ 10,966.0**	**$ 156.0**	**$ 8,902.6**	**$ 199.3**

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
System Installed Costs	CB1.1	$ 6,236.8	$ 88.7	$ 5,085.4	$ 113.9
Ongoing O&M + Insurance Costs	CB1.2	$ 879.3	$ 12.5	$ 859.7	$ 19.2
Lease Payments	CB1.3	$ 203.8	$ 2.9	$ 198.1	$ 4.4
PILOTs / Property Taxes	CB1.4	$ 146.8	$ 2.1	$ 142.9	$ 3.2
MA Income Taxes	CB1.6.b	$ 211.0	$ 3.0	$ 85.7	$ 1.9
Federal Income Taxes	CB1.7b	$ 922.9	$ 13.1	$ 375.1	$ 8.4
Solar Policy Incr. Admin. & Transaction Costs	CB2.4	$ 69.9	$ 1.0	$ 16.4	$ 0.4
Total		**$ 8,670.5**	**$ 123.3**	**$ 6,763.3**	**$ 151.4**

(11)

CG Costs and Benefits – Policy B 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
ROI (Aggregate Return to Debt & Equity)	CB1.5	$ -	$ -	$ -	$ -
MA Residential RE Tax Credit	CB1.6.a	$ 60.0	$ 0.9	$ 43.8	$ 1.0
Federal Incentives (ITC)	CB1.7a	$ 1,325.7	$ 18.8	$ 1,248.6	$ 27.9
Direct Incentives (e.g., SRECs)	CB2.1	$ 4,173.2	$ 59.2	$ 3,577.5	$ 80.0
Generation Value of On-site Generation	CB3.1	$ 1,468.3	$ 20.8	$ 827.0	$ 18.5
Transmission Value of On-site Generation	CB3.2	$ 228.2	$ 3.2	$ 138.9	$ 3.1
Distribution Value of On-site Generation	CB3.3	$ 575.3	$ 8.2	$ 344.1	$ 7.7
Other Retail Bill Components (Trans., EE, RE)	CB3.4	$ 91.2	$ 1.3	$ 55.4	$ 1.2
Offsetting On-site Usage	CB4.1	$ 131.0	$ 1.9	$ 99.5	$ 2.2
Virtual NM	CB4.2	$ 2,409.7	$ 34.2	$ 2,409.7	$ 53.9
Wholesale Market Sales	CB4.3	$ 838.6	$ 11.9	$ 234.9	$ 5.3
Avoided Generation Capacity Costs	CB5.3	$ 119.2	$ 1.7	$ 77.8	$ 1.7
Total		**$ 11,420.4**	**$ 162.1**	**$ 9,057.2**	**$ 202.6**

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
System Installed Costs	CB1.1	$ 6,224.5	$ 88.4	$ 5,086.3	$ 113.8
Ongoing O&M + Insurance Costs	CB1.2	$ 1,315.2	$ 18.7	$ 964.8	$ 21.6
Lease Payments	CB1.3	$ 299.1	$ 4.2	$ 222.4	$ 5.0
PILOTs / Property Taxes	CB1.4	$ 204.3	$ 2.9	$ 157.5	$ 3.5
MA Income Taxes	CB1.6.b	$ 188.9	$ 2.7	$ 118.0	$ 2.6
Federal Income Taxes	CB1.7b	$ 826.5	$ 11.7	$ 510.3	$ 11.4
Solar Policy Incr. Admin. & Transaction Costs	CB2.4	$ -	$ -	$ -	$ -
Total		**$ 9,058.4**	**$ 128.6**	**$ 7,059.2**	**$ 157.9**

(12)

CG Costs and Benefits – Policy B Uncapped

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
ROI (Aggregate Return to Debt & Equity)	CB1.5	$ -	$ -	$ -	$ -
MA Residential RE Tax Credit	CB1.6.a	$ 59.1	$ 0.8	$ 43.4	$ 1.0
Federal Incentives (ITC)	CB1.7a	$ 1,334.5	$ 19.0	$ 1,255.7	$ 28.1
Direct Incentives (e.g., SRECs)	CB2.1	$ 3,418.6	$ 48.6	$ 3,496.4	$ 78.3
Generation Value of On-site Generation	CB3.1	$ 1,277.5	$ 18.2	$ 788.0	$ 17.6
Transmission Value of On-site Generation	CB3.2	$ 203.9	$ 2.9	$ 132.3	$ 3.0
Distribution Value of On-site Generation	CB3.3	$ 492.0	$ 7.0	$ 323.5	$ 7.2
Other Retail Bill Components (Trans., EE, RE)	CB3.4	$ 81.3	$ 1.2	$ 53.2	$ 1.2
Offsetting On-site Usage	CB4.1	$ 159.0	$ 2.3	$ 105.2	$ 2.4
Virtual NM	CB4.2	$ 4,197.8	$ 59.7	$ 2,842.0	$ 63.6
Wholesale Market Sales	CB4.3	$ -	$ -	$ -	$ -
Avoided Generation Capacity Costs	CB5.3	$ 119.3	$ 1.7	$ 77.8	$ 1.7
Total		**$ 11,342.9**	**$ 161.3**	**$ 9,117.4**	**$ 204.2**

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
System Installed Costs	CB1.1	$ 6,274.2	$ 89.2	$ 5,095.9	$ 114.1
Ongoing O&M + Insurance Costs	CB1.2	$ 1,365.4	$ 19.4	$ 976.1	$ 21.9
Lease Payments	CB1.3	$ 299.1	$ 4.3	$ 222.0	$ 5.0
PILOTs / Property Taxes	CB1.4	$ 213.2	$ 3.0	$ 159.5	$ 3.6
MA Income Taxes	CB1.6.b	$ 236.6	$ 3.4	$ 91.9	$ 2.1
Federal Income Taxes	CB1.7b	$ 1,035.3	$ 14.7	$ 402.0	$ 9.0
Solar Policy Incr. Admin. & Transaction Costs	CB2.4	$ -	$ -	$ -	$ -
Total		**$ 9,423.8**	**$ 134.0**	**$ 6,947.4**	**$ 155.6**

(13)

NPR 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 Transmission Investment - Local	CB6.2	$ 102.5	$ 1.5	$ 88.6	$ 2.0
Avoided Distribution Investment	CB6.3	$ 232.4	$ 3.4	$ 200.9	$ 4.6
Avoided Environmental Impacts	CB7.1	$ 710.8	$ 10.3	$ 660.0	$ 15.1
Total		**$ 5,270.6**	**$ 76.5**	**$ 3,958.8**	**$ 90.9**

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**

(14)

NPR Costs and Benefits – SREC Uncapped

Benefits

C/B Component ↓	CB Code	1600 MW NPV Benefits	1600 MW NPV $/MWh Benefits
MA Income Taxes	CB1.6.b	$ 76.1	$ 1.7
Displaced RPS Class I Compliance Costs	CB2.3	$ 893.5	$ 20.5
Generation Value of On-site Generation	CB3.1	$ 48.0	$ 1.1
Wholesale Market Sales	CB4.3	$ -	$ -
Wholesale Market Price Impacts - Energy	CB5.1	$ 64.4	$ 1.5
Avoided Generation Capacity Costs	CB5.3	$ 1,549.3	$ 35.6
Avoided Transmission Tariff Charges	CB5.5	$ 148.2	$ 3.4
Avoided Trans. Investment - Remote Wind	CB6.1	$ 112.5	$ 2.6
Avoided Transmission Investment - Local	CB6.2	$ 88.5	$ 2.0
Avoided Distribution Investment	CB6.3	$ 200.6	$ 4.6
Avoided Environmental Impacts	CB7.1	$ 660.0	$ 15.2
Total		**$ 3,841.1**	**$ 88.2**

Costs

C/B Component ↓	CB Code	1600 MW NPV Costs (Million $)	1600 MW NPV $/MWh Costs
MA Residential RE Tax Credit	CB1.6.a	$ 42.4	$ 1.0
Direct Incentives (e.g., SRECs)	CB2.1	$ 3,812.7	$ 87.6
Other Solar Policy Compliance Costs (e.g. SACP)	CB2.2	$ 167.1	$ 3.8
Solar Policy Incr. Admin. & Transaction Costs	CB2.4	$ -	$ -
Transmission Value of On-site Generation	CB3.2	$ 146.6	$ 3.4
Distribution Value of On-site Generation	CB3.3	$ 358.6	$ 8.2
Other Retail Bill Components (Trans., EE, RE)	CB3.4	$ 52.2	$ 1.2
Offsetting On-site Usage	CB4.1	$ 60.3	$ 1.4
Virtual NM	CB4.2	$ 1,920.0	$ 44.1
Total		**$ 6,559.9**	**$ 150.7**

(15)

NPR Costs and Benefits – Policy A 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	$ 285.5	$ 4.1	$ 175.0	$ 3.9
Displaced RPS Class I Compliance Costs	CB2.3	$ 1,552.6	$ 22.0	$ 961.4	$ 21.5
Generation Value of On-site Generation	CB3.1	$ 91.1	$ 1.3	$ 52.6	$ 1.2
Wholesale Market Sales	CB4.3	$ 47.0	$ 0.7	$ 12.7	$ 0.3
Wholesale Market Price Impacts - Energy	CB5.1	$ 54.4	$ 0.8	$ 64.4	$ 1.4
Avoided Generation Capacity Costs	CB5.3	$ 2,103.3	$ 29.9	$ 1,552.6	$ 34.7
Avoided Transmission Tariff Charges	CB5.5	$ 172.6	$ 2.4	$ 148.4	$ 3.3
Avoided Trans. Investment - Remote Wind	CB6.1	$ 181.8	$ 2.6	$ 112.5	$ 2.5
Avoided Transmission Investment - Local	CB6.2	$ 107.3	$ 1.5	$ 90.7	$ 2.0
Avoided Distribution Investment	CB6.3	$ 243.2	$ 3.5	$ 205.6	$ 4.6
Avoided Environmental Impacts	CB7.1	$ 710.8	$ 10.1	$ 660.0	$ 14.8
Total		**$ 5,549.5**	**$ 78.8**	**$ 4,035.8**	**$ 90.3**

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 Residential RE Tax Credit	CB1.6.a	$ 59.8	$ 0.8	$ 43.8	$ 1.0
Direct Incentives (e.g., SRECs)	CB2.1	$ 4,589.4	$ 65.2	$ 3,838.8	$ 85.9
Other Solar Policy Compliance Costs (e.g. SACP)	CB2.2	$ 191.1	$ 2.7	$ 191.1	$ 4.3
Solar Policy Incr. Admin. & Transaction Costs	CB2.4	$ 197.4	$ 2.8	$ 63.5	$ 1.4
Transmission Value of On-site Generation	CB3.2	$ 238.2	$ 3.4	$ 155.9	$ 3.5
Distribution Value of On-site Generation	CB3.3	$ 615.2	$ 8.7	$ 385.3	$ 8.6
Other Retail Bill Components (Trans., EE, RE)	CB3.4	$ 91.0	$ 1.3	$ 56.9	$ 1.3
Offsetting On-site Usage	CB4.1	$ 52.7	$ 0.7	$ 52.6	$ 1.2
Virtual NM	CB4.2	$ 1,668.0	$ 23.7	$ 1,663.5	$ 37.2
Total		**$ 7,702.9**	**$ 109.4**	**$ 6,451.3**	**$ 144.3**

(16)

NPR Costs and Benefits – Policy A Uncapped

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	$ 247.6	$ 3.5	$ 134.7	$ 3.0
Displaced RPS Class I Compliance Costs	CB2.3	$ 1,515.0	$ 21.5	$ 949.6	$ 21.3
Generation Value of On-site Generation	CB3.1	$ 77.8	$ 1.1	$ 49.4	$ 1.1
Wholesale Market Sales	CB4.3	$ -	$ -	$ -	$ -
Wholesale Market Price Impacts - Energy	CB5.1	$ 54.4	$ 0.8	$ 64.4	$ 1.4
Avoided Generation Capacity Costs	CB5.3	$ 2,101.6	$ 29.9	$ 1,551.2	$ 34.7
Avoided Transmission Tariff Charges	CB5.5	$ 172.3	$ 2.5	$ 148.2	$ 3.3
Avoided Trans. Investment - Remote Wind	CB6.1	$ 181.8	$ 2.6	$ 112.5	$ 2.5
Avoided Transmission Investment - Local	CB6.2	$ 106.9	$ 1.5	$ 90.5	$ 2.0
Avoided Distribution Investment	CB6.3	$ 242.3	$ 3.4	$ 205.1	$ 4.6
Avoided Environmental Impacts	CB7.1	$ 710.8	$ 10.1	$ 660.0	$ 14.8
Total		**$ 5,410.4**	**$ 76.9**	**$ 3,965.6**	**$ 88.8**

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	$ 58.8	$ 0.8	$ 43.2	$ 1.0
Direct Incentives (e.g., SRECs)	CB2.1	$ 4,080.3	$ 58.0	$ 3,696.4	$ 82.8
Other Solar Policy Compliance Costs (e.g. SACP)	CB2.2	$ 191.7	$ 2.7	$ 191.7	$ 4.3
Solar Policy Incr. Admin. & Transaction Costs	CB2.4	$ 108.1	$ 1.5	$ 61.8	$ 1.4
Transmission Value of On-site Generation	CB3.2	$ 201.9	$ 2.9	$ 148.0	$ 3.3
Distribution Value of On-site Generation	CB3.3	$ 500.3	$ 7.1	$ 360.4	$ 8.1
Other Retail Bill Components (Trans., EE, RE)	CB3.4	$ 81.3	$ 1.2	$ 54.1	$ 1.2
Offsetting On-site Usage	CB4.1	$ 52.9	$ 0.8	$ 52.7	$ 1.2
Virtual NM	CB4.2	$ 1,652.6	$ 23.5	$ 1,648.1	$ 36.9
Total		**$ 6,927.9**	**$ 98.5**	**$ 6,256.5**	**$ 140.1**

(17)

NPR Costs and Benefits – Policy B 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	$ 251.7	$ 3.6	$ 169.7	$ 3.8
Displaced RPS Class I Compliance Costs	CB2.3	$ 1,555.7	$ 22.1	$ 960.7	$ 21.5
Generation Value of On-site Generation	CB3.1	$ 90.9	$ 1.3	$ 51.9	$ 1.2
Wholesale Market Sales	CB4.3	$ 46.8	$ 0.7	$ 13.1	$ 0.3
Wholesale Market Price Impacts - Energy	CB5.1	$ 54.4	$ 0.8	$ 64.4	$ 1.4
Avoided Generation Capacity Costs	CB5.3	$ 2,100.5	$ 29.8	$ 1,552.8	$ 34.7
Avoided Transmission Tariff Charges	CB5.5	$ 172.2	$ 2.4	$ 148.6	$ 3.3
Avoided Trans. Investment - Remote Wind	CB6.1	$ 181.8	$ 2.6	$ 112.5	$ 2.5
Avoided Transmission Investment - Local	CB6.2	$ 107.1	$ 1.5	$ 90.8	$ 2.0
Avoided Distribution Investment	CB6.3	$ 242.8	$ 3.4	$ 205.8	$ 4.6
Avoided Environmental Impacts	CB7.1	$ 710.8	$ 10.1	$ 660.0	$ 14.8
Total		**$ 5,514.8**	**$ 78.3**	**$ 4,030.4**	**$ 90.2**

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	$ 60.0	$ 0.9	$ 43.8	$ 1.0
Direct Incentives (e.g., SRECs)	CB2.1	$ 4,419.7	$ 62.7	$ 3,824.0	$ 85.5
Other Solar Policy Compliance Costs (e.g. SACP)	CB2.2	$ 191.1	$ 2.7	$ 191.1	$ 4.3
Solar Policy Incr. Admin. & Transaction Costs	CB2.4	$ 85.3	$ 1.2	$ 30.3	$ 0.7
Transmission Value of On-site Generation	CB3.2	$ 254.0	$ 3.6	$ 156.0	$ 3.5
Distribution Value of On-site Generation	CB3.3	$ 641.9	$ 9.1	$ 386.0	$ 8.6
Other Retail Bill Components (Trans., EE, RE)	CB3.4	$ 91.6	$ 1.3	$ 56.2	$ 1.3
Offsetting On-site Usage	CB4.1	$ 76.9	$ 1.1	$ 58.8	$ 1.3
Virtual NM	CB4.2	$ 1,668.0	$ 23.7	$ 1,663.5	$ 37.2
Total		**$ 7,488.5**	**$ 106.3**	**$ 6,409.7**	**$ 143.4**

(18)

NPR Costs and Benefits – Policy B Uncapped

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	$ 282.3	$ 4.0	$ 144.9	$ 3.2
Displaced RPS Class I Compliance Costs	CB2.3	$ 1,520.2	$ 21.6	$ 950.2	$ 21.3
Generation Value of On-site Generation	CB3.1	$ 78.7	$ 1.1	$ 49.4	$ 1.1
Wholesale Market Sales	CB4.3	$ -	$ -	$ -	$ -
Wholesale Market Price Impacts - Energy	CB5.1	$ 54.4	$ 0.8	$ 64.4	$ 1.4
Avoided Generation Capacity Costs	CB5.3	$ 2,100.7	$ 29.9	$ 1,551.3	$ 34.7
Avoided Transmission Tariff Charges	CB5.5	$ 172.2	$ 2.4	$ 148.3	$ 3.3
Avoided Trans. Investment - Remote Wind	CB6.1	$ 181.8	$ 2.6	$ 112.5	$ 2.5
Avoided Transmission Investment - Local	CB6.2	$ 106.9	$ 1.5	$ 90.6	$ 2.0
Avoided Distribution Investment	CB6.3	$ 242.2	$ 3.4	$ 205.3	$ 4.6
Avoided Environmental Impacts	CB7.1	$ 710.8	$ 10.1	$ 660.0	$ 14.8
Total		**$ 5,450.2**	**$ 77.5**	**$ 3,977.0**	**$ 89.1**

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	$ 59.1	$ 0.8	$ 43.4	$ 1.0
Direct Incentives (e.g., SRECs)	CB2.1	$ 3,668.6	$ 52.2	$ 3,599.4	$ 80.6
Other Solar Policy Compliance Costs (e.g. SACP)	CB2.2	$ 191.7	$ 2.7	$ 191.7	$ 4.3
Solar Policy Incr. Admin. & Transaction Costs	CB2.4	$ 85.1	$ 1.2	$ 30.2	$ 0.7
Transmission Value of On-site Generation	CB3.2	$ 225.6	$ 3.2	$ 148.4	$ 3.3
Distribution Value of On-site Generation	CB3.3	$ 544.3	$ 7.7	$ 362.7	$ 8.1
Other Retail Bill Components (Trans., EE, RE)	CB3.4	$ 81.5	$ 1.2	$ 54.0	$ 1.2
Offsetting On-site Usage	CB4.1	$ 90.0	$ 1.3	$ 61.4	$ 1.4
Virtual NM	CB4.2	$ 2,742.0	$ 39.0	$ 1,885.7	$ 42.2
Total		**$ 7,687.9**	**$ 109.3**	**$ 6,376.9**	**$ 142.8**

(19)

C@L 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 Transmission Investment - Local	CB6.2	$ 102.5	$ 1.5	$ 88.6	$ 2.0
Avoided Distribution Investment	CB6.3	$ 232.4	$ 3.4	$ 200.9	$ 4.6
Avoided Environmental Impacts	CB7.1	$ 710.8	$ 10.3	$ 660.0	$ 15.1
Total		**$ 14,581.0**	**$ 211.7**	**$ 10,354.3**	**$ 237.6**

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**

(20)

C@L Costs and Benefits – SREC Uncapped

Benefits

C/B Component ↓	CB Code	1600 MW NPV Benefits (Million $)	1600 MW NPV $/MWh Benefits
System Installed Costs	CB1.1	$ 2,157.3	$ 49.6
Ongoing O&M + Insurance Costs	CB1.2	$ 631.5	$ 14.5
Lease Payments	CB1.3	$ 223.4	$ 5.1
PILOTs / Property Taxes	CB1.4	$ 160.7	$ 3.7
ROI (Aggregate Return to Debt & Equity)	CB1.5	$ 761.2	$ 17.5
Federal Incentives (ITC)	CB1.7a	$ 188.7	$ 4.3
Displaced RPS Class I Compliance Costs	CB2.3	$ 893.5	$ 20.5
Generation Value of On-site Generation	CB3.1	$ 908.1	$ 20.9
Other Retail Bill Components (Trans., EE, RE)	CB3.4	$ 5.8	$ 0.1
Offsetting On-site Usage	CB4.1	$ 51.9	$ 1.2
Virtual NM	CB4.2	$ 1,496.4	$ 34.4
Wholesale Market Sales	CB4.3	$ -	$ -
Wholesale Market Price Impacts - Energy	CB5.1	$ 64.4	$ 1.5
Avoided Generation Capacity Costs	CB5.3	$ 1,627.1	$ 37.4
Avoided Transmission Tariff Charges	CB5.5	$ 148.2	$ 3.4
Avoided Trans. Investment - Remote Wind	CB6.1	$ 112.5	$ 2.6
Avoided Transmission Investment - Local	CB6.2		
Avoided Distribution Investment	CB6.3		
Avoided Environmental Impacts	CB7.1	$ 660.0	$ 15.2
Total		**$ 10,090.7**	**$ 231.8**

Costs

C/B Component ↓	CB Code	1600 MW NPV Costs (Million $)	1600 MW NPV $/MWh Costs
Federal Income Taxes	CB1.7b	$ 332.8	$ 7.6
Direct Incentives (e.g., SRECs)	CB2.1	$ 3,812.7	$ 87.6
Solar Policy Incr. Admin. & Transaction Costs	CB2.4	$ -	$ -
Total		**$ 4,145.4**	**$ 95.2**

(21)

C@L Costs and Benefits – Policy A 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	$ 2,632.4	$ 37.4	$ 2,139.6	$ 47.9
Ongoing O&M + Insurance Costs	CB1.2	$ 813.2	$ 11.5	$ 607.7	$ 13.6
Lease Payments	CB1.3	$ 304.3	$ 4.3	$ 222.7	$ 5.0
PILOTs / Property Taxes	CB1.4	$ 204.3	$ 2.9	$ 156.8	$ 3.5
ROI (Aggregate Return to Debt & Equity)	CB1.5	$ 668.3	$ 9.5	$ 590.2	$ 13.2
Federal Incentives (ITC)	CB1.7a	$ 200.3	$ 2.8	$ 187.7	$ 4.2
Displaced RPS Class I Compliance Costs	CB2.3	$ 1,552.6	$ 22.0	$ 961.4	$ 21.5
Generation Value of On-site Generation	CB3.1	$ 1,721.8	$ 24.4	$ 993.7	$ 22.2
Other Retail Bill Components (Trans., EE, RE)	CB3.4	$ 10.1	$ 0.1	$ 6.3	$ 0.1
Offsetting On-site Usage	CB4.1	$ 71.6	$ 1.0	$ 51.3	$ 1.1
Virtual NM	CB4.2	$ 1,194.8	$ 17.0	$ 1,199.3	$ 26.8
Wholesale Market Sales	CB4.3	$ 888.1	$ 12.6	$ 239.3	$ 5.4
Wholesale Market Price Impacts - Energy	CB5.1	$ 54.4	$ 0.8	$ 64.4	$ 1.4
Avoided Generation Capacity Costs	CB5.3	$ 2,222.3	$ 31.5	$ 1,630.4	$ 36.5
Avoided Transmission Tariff Charges	CB5.5	$ 172.6	$ 2.4	$ 148.4	$ 3.3
Avoided Trans. Investment - Remote Wind	CB6.1	$ 181.8	$ 2.6	$ 112.5	$ 2.5
Avoided Transmission Investment - Local	CB6.2	$ 107.3	$ 1.5	$ 90.7	$ 2.0
Avoided Distribution Investment	CB6.3	$ 243.2	$ 3.5	$ 205.6	$ 4.6
Avoided Environmental Impacts	CB7.1	$ 710.8	$ 10.1	$ 660.0	$ 14.8
Total		**$ 13,954.3**	**$ 198.1**	**$ 10,268.0**	**$ 229.7**

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	$ 1,249.0	$ 17.7	$ 765.6	$ 17.1
Direct Incentives (e.g., SRECs)	CB2.1	$ 4,589.4	$ 65.2	$ 3,838.8	$ 85.9
Solar Policy Incr. Admin. & Transaction Costs	CB2.4	$ 197.4	$ 2.8	$ 63.5	$ 1.4
Total		**$ 6,035.8**	**$ 85.7**	**$ 4,667.9**	**$ 104.4**

(22)

C@L Costs and Benefits – Policy A Uncapped

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	$ 2,619.5	$ 37.3	$ 2,135.9	$ 47.8
Ongoing O&M + Insurance Costs	CB1.2	$ 562.7	$ 8.0	$ 550.2	$ 12.3
Lease Payments	CB1.3	$ 203.8	$ 2.9	$ 198.1	$ 4.4
PILOTs / Property Taxes	CB1.4	$ 146.8	$ 2.1	$ 142.9	$ 3.2
ROI (Aggregate Return to Debt & Equity)	CB1.5	$ 688.7	$ 9.8	$ 641.8	$ 14.4
Federal Incentives (ITC)	CB1.7a	$ 200.6	$ 2.9	$ 188.5	$ 4.2
Displaced RPS Class I Compliance Costs	CB2.3	$ 1,515.0	$ 21.5	$ 949.6	$ 21.3
Generation Value of On-site Generation	CB3.1	$ 1,471.1	$ 20.9	$ 933.1	$ 20.9
Other Retail Bill Components (Trans., EE, RE)	CB3.4	$ 9.0	$ 0.1	$ 6.0	$ 0.1
Offsetting On-site Usage	CB4.1	$ 92.3	$ 1.3	$ 55.6	$ 1.2
Virtual NM	CB4.2	$ 2,519.7	$ 35.8	$ 1,537.1	$ 34.4
Wholesale Market Sales	CB4.3	$ -	$ -	$ -	$ -
Wholesale Market Price Impacts - Energy	CB5.1	$ 54.4	$ 0.8	$ 64.4	$ 1.4
Avoided Generation Capacity Costs	CB5.3	$ 2,220.7	$ 31.6	$ 1,629.0	$ 36.5
Avoided Transmission Tariff Charges	CB5.5	$ 172.3	$ 2.5	$ 148.2	$ 3.3
Avoided Trans. Investment - Remote Wind	CB6.1	$ 181.8	$ 2.6	$ 112.5	$ 2.5
Avoided Transmission Investment - Local	CB6.2	$ 106.9	$ 1.5	$ 90.5	$ 2.0
Avoided Distribution Investment	CB6.3	$ 242.3	$ 3.4	$ 205.1	$ 4.6
Avoided Environmental Impacts	CB7.1	$ 710.8	$ 10.1	$ 660.0	$ 14.8
Total		**$ 13,718.3**	**$ 195.1**	**$ 10,248.4**	**$ 229.5**

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	$ 1,083.1	$ 15.4	$ 589.3	$ 13.2
Direct Incentives (e.g., SRECs)	CB2.1	$ 4,080.3	$ 58.0	$ 3,696.4	$ 82.8
Solar Policy Incr. Admin. & Transaction Costs	CB2.4	$ 108.1	$ 1.5	$ 61.8	$ 1.4
Total		**$ 5,271.6**	**$ 75.0**	**$ 4,347.5**	**$ 97.3**

(23)

C@L Costs and Benefits – Policy B 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	$ 2,614.3	$ 37.1	$ 2,136.2	$ 47.8
Ongoing O&M + Insurance Costs	CB1.2	$ 841.7	$ 11.9	$ 617.5	$ 13.8
Lease Payments	CB1.3	$ 299.1	$ 4.2	$ 222.4	$ 5.0
PILOTs / Property Taxes	CB1.4	$ 204.3	$ 2.9	$ 157.5	$ 3.5
ROI (Aggregate Return to Debt & Equity)	CB1.5	$ 708.6	$ 10.1	$ 599.4	$ 13.4
Federal Incentives (ITC)	CB1.7a	$ 198.9	$ 2.8	$ 187.3	$ 4.2
Displaced RPS Class I Compliance Costs	CB2.3	$ 1,555.7	$ 22.1	$ 960.7	$ 21.5
Generation Value of On-site Generation	CB3.1	$ 1,719.3	$ 24.4	$ 981.1	$ 21.9
Other Retail Bill Components (Trans., EE, RE)	CB3.4	$ 9.9	$ 0.1	$ 6.3	$ 0.1
Offsetting On-site Usage	CB4.1	$ 65.9	$ 0.9	$ 49.9	$ 1.1
Virtual NM	CB4.2	$ 1,194.8	$ 17.0	$ 1,199.3	$ 26.8
Wholesale Market Sales	CB4.3	$ 885.5	$ 12.6	$ 248.0	$ 5.5
Wholesale Market Price Impacts - Energy	CB5.1	$ 54.4	$ 0.8	$ 64.4	$ 1.4
Avoided Generation Capacity Costs	CB5.3	$ 2,219.7	$ 31.5	$ 1,630.6	$ 36.5
Avoided Transmission Tariff Charges	CB5.5	$ 172.2	$ 2.4	$ 148.6	$ 3.3
Avoided Trans. Investment - Remote Wind	CB6.1	$ 181.8	$ 2.6	$ 112.5	$ 2.5
Avoided Transmission Investment - Local	CB6.2	$ 107.1	$ 1.5	$ 90.8	$ 2.0
Avoided Distribution Investment	CB6.3	$ 242.8	$ 3.4	$ 205.8	$ 4.6
Avoided Environmental Impacts	CB7.1	$ 710.8	$ 10.1	$ 660.0	$ 14.8
Total		**$ 13,986.6**	**$ 198.6**	**$ 10,278.3**	**$ 229.9**

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	$ 1,101.2	$ 15.6	$ 736.4	$ 16.5
Direct Incentives (e.g., SRECs)	CB2.1	$ 4,419.7	$ 62.7	$ 3,824.0	$ 85.5
Solar Policy Incr. Admin. & Transaction Costs	CB2.4	$ 85.3	$ 1.2	$ 30.3	$ 0.7
Total		**$ 5,606.2**	**$ 79.6**	**$ 4,590.7**	**$ 102.7**

(24)

C@L Costs and Benefits – Policy B Uncapped

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	$ 2,635.2	$ 37.5	$ 2,140.3	$ 47.9
Ongoing O&M + Insurance Costs	CB1.2	$ 873.8	$ 12.4	$ 624.7	$ 14.0
Lease Payments	CB1.3	$ 299.1	$ 4.3	$ 222.0	$ 5.0
PILOTs / Property Taxes	CB1.4	$ 213.2	$ 3.0	$ 159.5	$ 3.6
ROI (Aggregate Return to Debt & Equity)	CB1.5	$ 575.7	$ 8.2	$ 651.0	$ 14.6
Federal Incentives (ITC)	CB1.7a	$ 200.2	$ 2.8	$ 188.4	$ 4.2
Displaced RPS Class I Compliance Costs	CB2.3	$ 1,520.2	$ 21.6	$ 950.2	$ 21.3
Generation Value of On-site Generation	CB3.1	$ 1,488.6	$ 21.2	$ 934.5	$ 20.9
Other Retail Bill Components (Trans., EE, RE)	CB3.4	$ 8.7	$ 0.1	$ 6.0	$ 0.1
Offsetting On-site Usage	CB4.1	$ 82.6	$ 1.2	$ 53.4	$ 1.2
Virtual NM	CB4.2	$ 2,231.3	$ 31.7	$ 1,476.7	$ 33.1
Wholesale Market Sales	CB4.3	$ -	$ -	$ -	$ -
Wholesale Market Price Impacts - Energy	CB5.1	$ 54.4	$ 0.8	$ 64.4	$ 1.4
Avoided Generation Capacity Costs	CB5.3	$ 2,220.0	$ 31.6	$ 1,629.2	$ 36.5
Avoided Transmission Tariff Charges	CB5.5	$ 172.2	$ 2.4	$ 148.3	$ 3.3
Avoided Trans. Investment - Remote Wind	CB6.1	$ 181.8	$ 2.6	$ 112.5	$ 2.5
Avoided Transmission Investment - Local	CB6.2	$ 106.9	$ 1.5	$ 90.6	$ 2.0
Avoided Distribution Investment	CB6.3	$ 242.2	$ 3.4	$ 205.3	$ 4.6
Avoided Environmental Impacts	CB7.1	$ 710.8	$ 10.1	$ 660.0	$ 14.8
Total		**$ 13,816.7**	**$ 196.5**	**$ 10,317.0**	**$ 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	$ 1,235.2	$ 17.6	$ 634.0	$ 14.2
Direct Incentives (e.g., SRECs)	CB2.1	$ 3,668.6	$ 52.2	$ 3,599.4	$ 80.6
Solar Policy Incr. Admin. & Transaction Costs	CB2.4	$ 85.1	$ 1.2	$ 30.2	$ 0.7
Total		**$ 4,989.0**	**$ 71.0**	**$ 4,263.7**	**$ 95.5**

(25)

Task 3 Report: Appendix C

Appendix C:

Task 3 - Analysis of Costs and Benefits: Policy Paths A & B Modeled Incentives

Massachusetts Net Metering and Solar Task Force

PEREGRINE ENERGY GROUP

Sustainable Energy Advantage, LLC

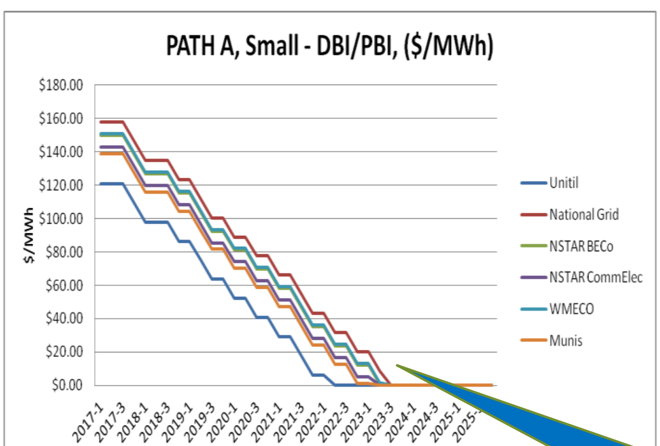
MEISTER CONSULTANTS GROUP

La Capra Associates

Policy Path A – Small Residential DBI/PBI

Slightly different DBI clearing speed function of slightly different starting tech. potential (**extremely** marginal effect)

Capped



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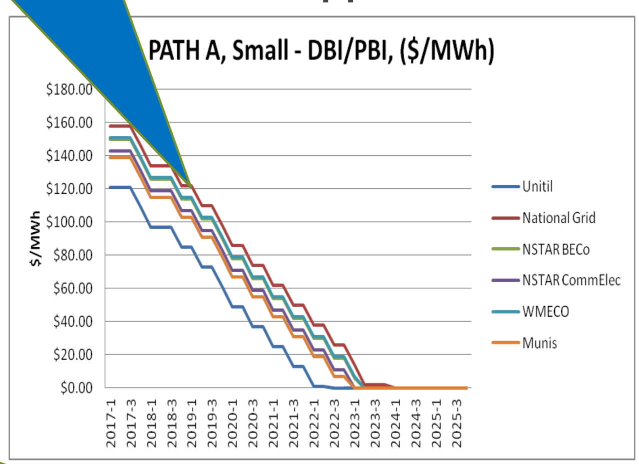


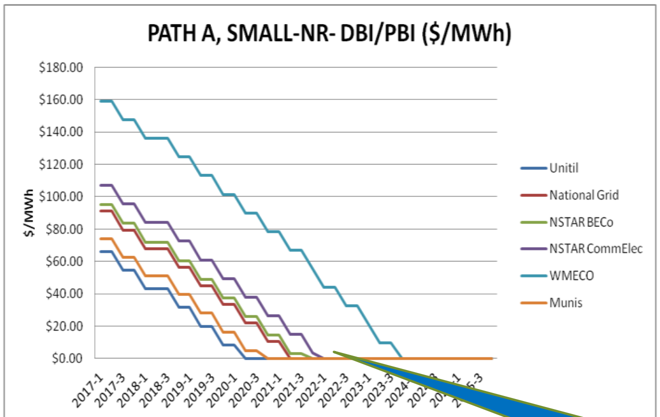
No PBI incentive needed Post-2023-Q2

(2)

Policy Path A – Small Non-Residential DBI/PBI

Slightly different DBI clearing speed function of slightly different starting tech. potential (**<u>extremely</u>** marginal effect)

Capped



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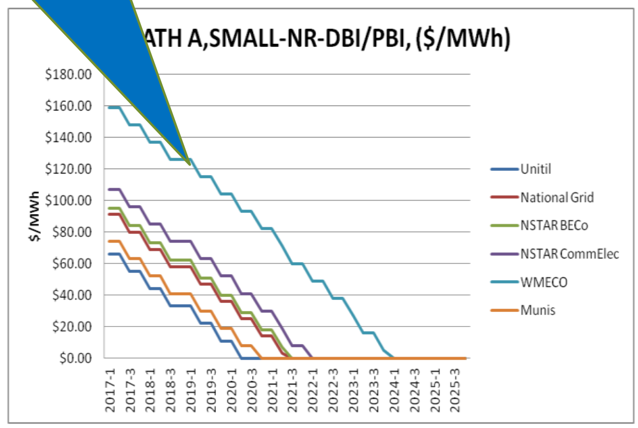


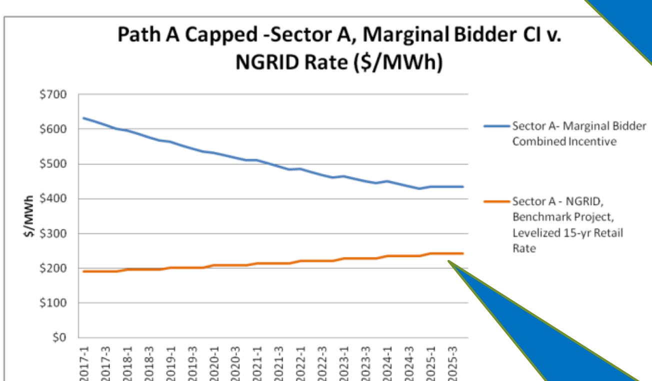
No PBI incentive needed Post-2021

(3)

Policy Path A – Large Competitive PBI – Sector A

When lines cross, Sector A which is dominated by CSS and VNM LIH do not need PBI with VNM.

Capped



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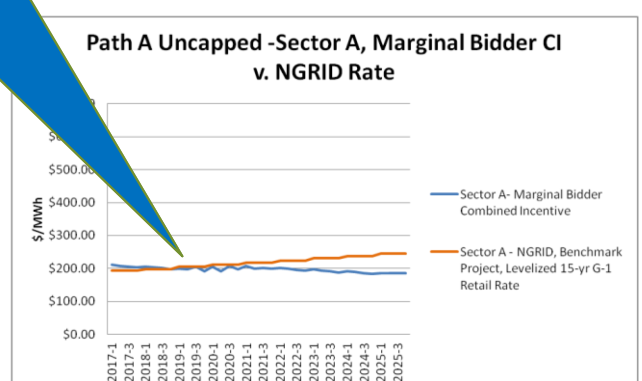


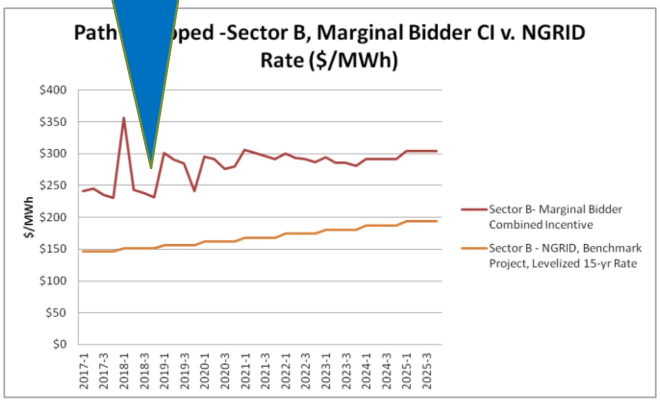
Marginal bid moves to convergence with rates, all Sectors.

(4)

Policy Path A – Large Competitive PBI – Sector B

Spikes reflect supply lumpiness and modeling method.

Capped



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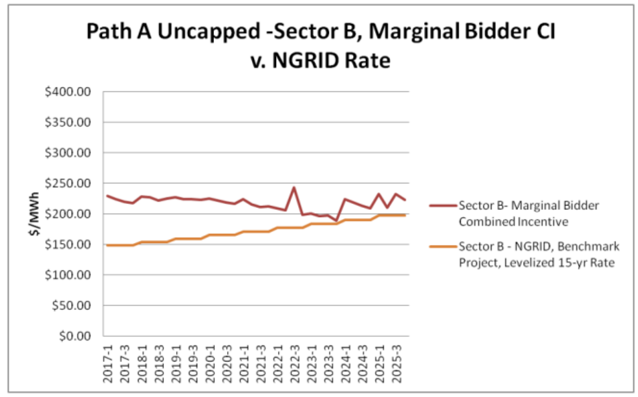
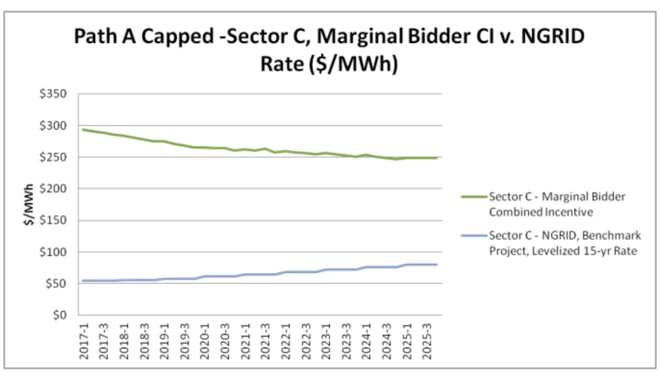


(5)

Policy Path A – Large Competitive PBI – Sector C

Higher Marginal Bid is function of modeling constraints, and not likely to be seen in practice. See Note.

Capped



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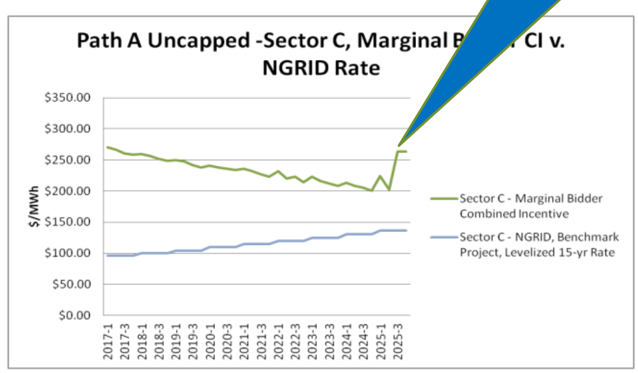
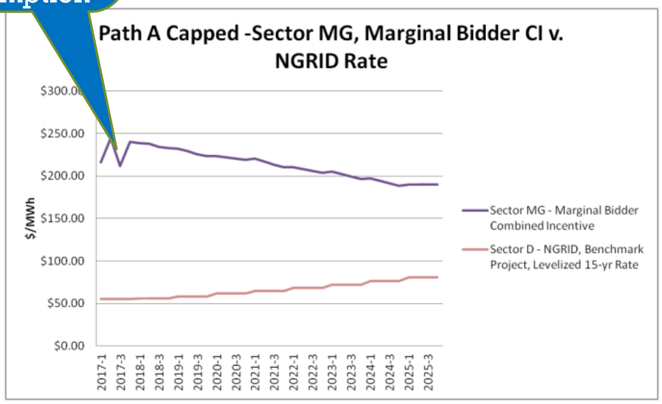


(6)

Policy Path A – Large Competitive PBI – Sector D

Spikes are reflective of "Price is Right" Modeling Assumption

Capped



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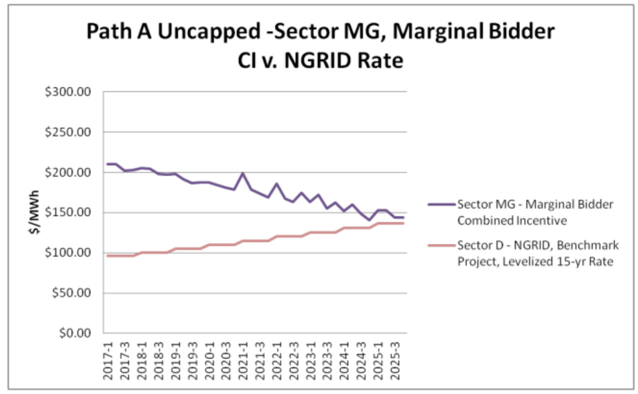
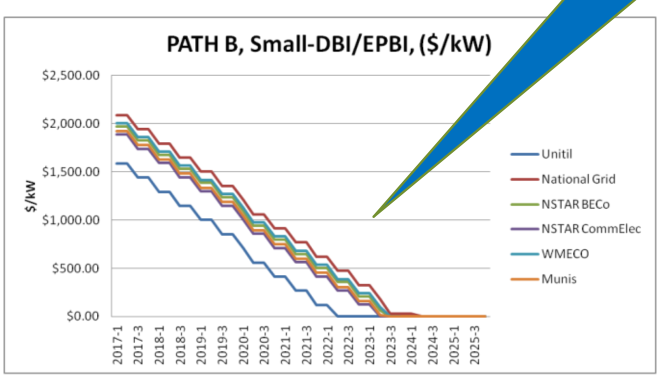


(7)

Policy Path B – Small Residential DBI/EPBI

Same for Both NM/ no NM

Capped



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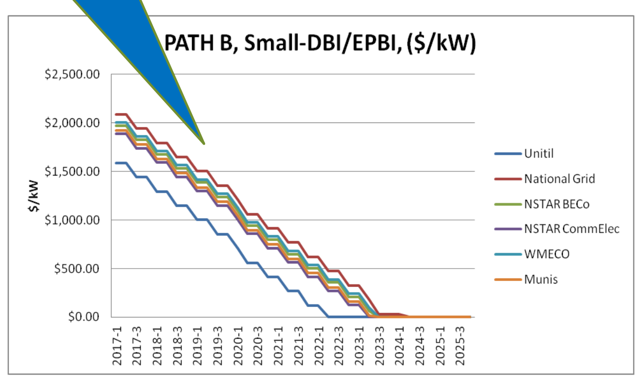
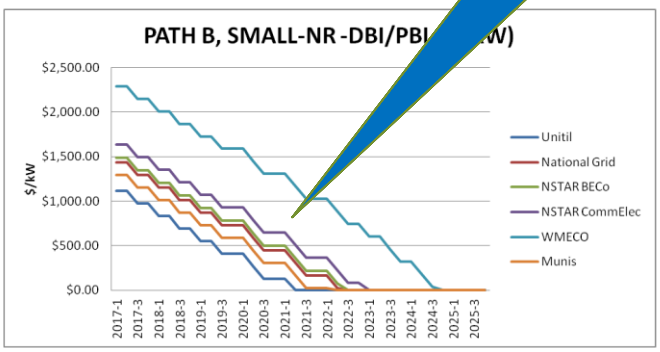


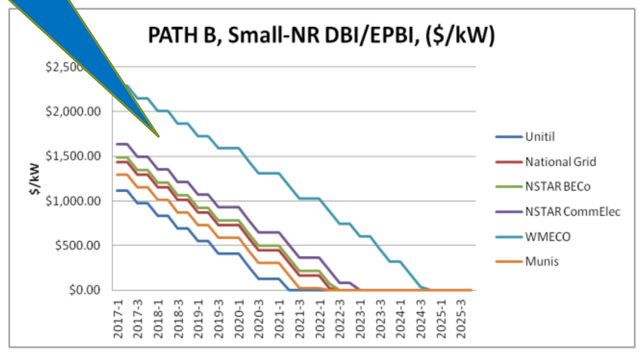
(8)

Policy Path B – Small Non-Residential DBI/EPBI

Same for Both NM/ no NM

Capped | **Uncapped**



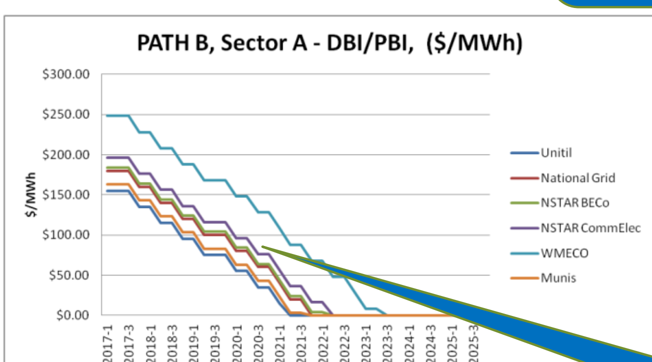


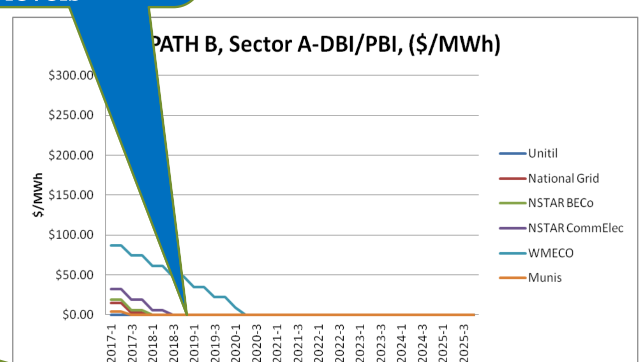
(9)

Policy Path B – Sector A DBI/PBI

By 2019, CSS and VNM LIH are no longer dependent on PBI at current NM levels

Capped | **Uncapped**



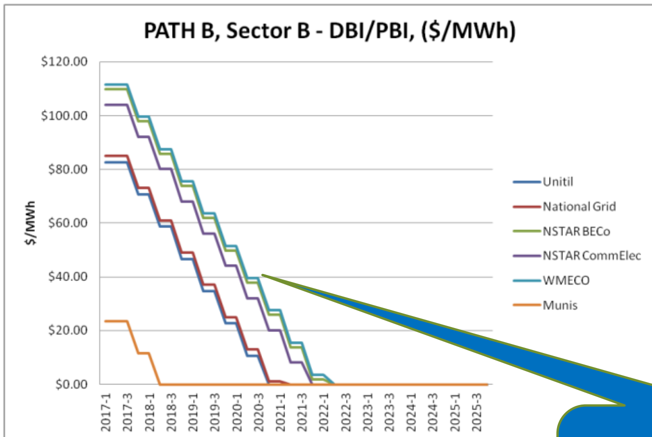


Comparative PBI levels must be viewed in context of lowered target (25%-10%)

(10)

Policy Path B – Sector B DBI/PBI

Capped



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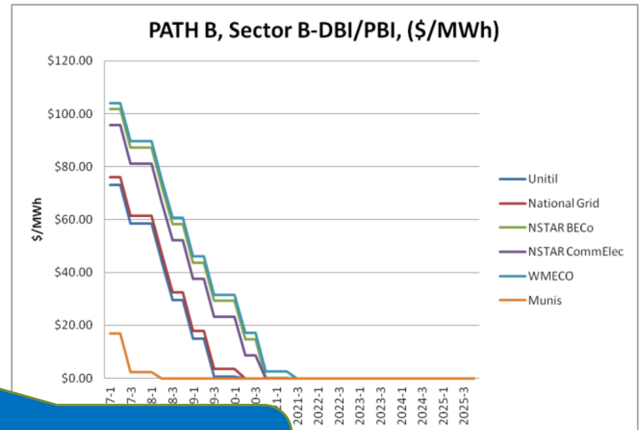


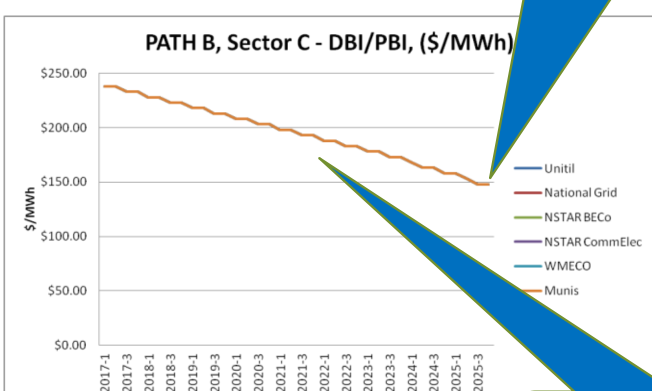
Comparative PBI levels must be viewed in context of raised target (25%-30%)

(11)

Policy Path B – Sector C DBI/PBI

Without NM retail rate is QF wholesale rate which is assumed equal across utility territories

Capped



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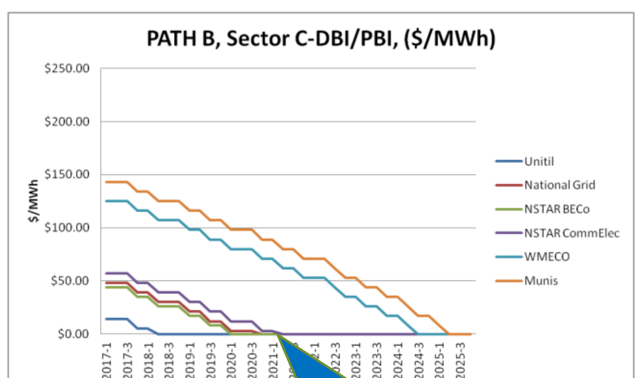


Comparative PBI levels must be viewed in context of raised target (25%-30%)

Most growth post-2020 is NM rate driven; signals no need for PBI after 2021

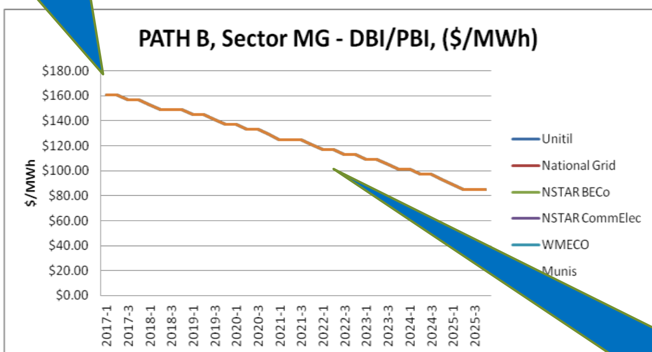
(12)

Policy Path B – Sector MG DBI/PBI

Without NM retail rate is QF wholesale rate which is assumed equal across utility territories

Most growth post 2021 is NM Rate Driven

Capped



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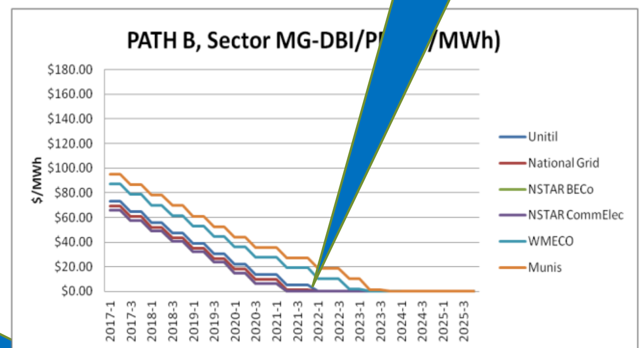


Comparative PBI levels must be viewed in context of raised target (25%-30%)

(13)

APPENDIX D: COMPONENTS OF COST/BENEFIT ANALYSIS

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

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

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

D.1 Overview of Cost Benefit Categories and Subcategories

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

D.1.1 Ratepayer & Participant Costs and Benefits

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

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

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

D.1.2 Secondary Costs and Benefits

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

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

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

D.2 Cost and Benefit Components and Level of Analysis

Within each of these categories, there are a number of individual cost and benefit components that comprise the individual impacts to be considered. Table 43 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 75: 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 43 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 44 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 76: Key to Cost and Benefit Description Tables

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

D.3 Category 1: PV System Costs

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

Subcategory	Code	Analysis
System Installed Costs	CB1.1	Quantitative
Ongoing O&M + Insurance Costs	CB1.2	Quantitative
Lease Payments	CB1.3	Quantitative
PILOTs / Property Taxes	CB1.4	Quantitative

ROI (to lenders & investors)	CB1.5	Quantitative
MA Residential RE Tax Credit	CB1.6a	Quantitative
MA Income Taxes	CB1.6b	Quantitative
Federal Incentives (ITC)	CB1.7a	Quantitative
Federal Income Taxes	CB1.7b	Quantitative

For ease of estimation, PV system installed and operating costs are assumed to be independent of the specific state policy futures, primarily driven by global module markets and local scale economies.[106] These costs vary by installation type and in some cases ownership model, but are held constant across alternative policy futures. When calculated installed costs throughout the baseline policy and alternative policy futures, the total costs per year can be stated as:

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

where

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

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

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

Table 45 below illustrates how these subcategories accrue as direct costs or benefits to the four perspectives analyzed.

Table 77: 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	- System Installed Costs	- Federal Income Taxes

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

the Commonwealth at Large **(C@L)**	- Lease Payments - PILOTs/Property Taxes - MA Income Taxes - ROI to Lenders/Investors	-

D.3.1 System Installed Costs

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

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

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

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

Table 78: PV System Installed Cost Impacts by Perspective

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

D.3.2 Ongoing O&M and Insurance Costs

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

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

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

Table 79: Ongoing O&M + Insurance Costs Impacts by Perspective

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

D.3.3 Lease Payments

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

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

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

Table 80: Land Lease Payments Impacts by Perspective

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

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

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

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

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

Table 81: PILOTs / Property Taxes Impacts by Perspective

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

D.3.5 Aggregate Return to Debt & Equity

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

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

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

Table 82: Aggregate Return to Debt & Equity Impacts by Perspective

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

D.3.6 Massachusetts Residential Renewable Energy Tax Credit

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

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

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

Table 83: MA Residential RE Tax Credit Impacts by Perspective

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

D.3.7 Massachusetts Income Taxes

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

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

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

Table 84: MA Income Taxes Impacts by Perspective

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

D.3.8 Federal Incentives (Investment Tax Credit)

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

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

Table 85: Federal Incentives (ITC) Impacts by Perspective

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

D.3.9 Federal Income Taxes

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

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

Table 86: Federal Income Taxes Impacts by Perspective

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

D.4 Category II: Solar Policy

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

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

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

Table 87: Solar Policy Impact Applicability to Analysis Perspectives

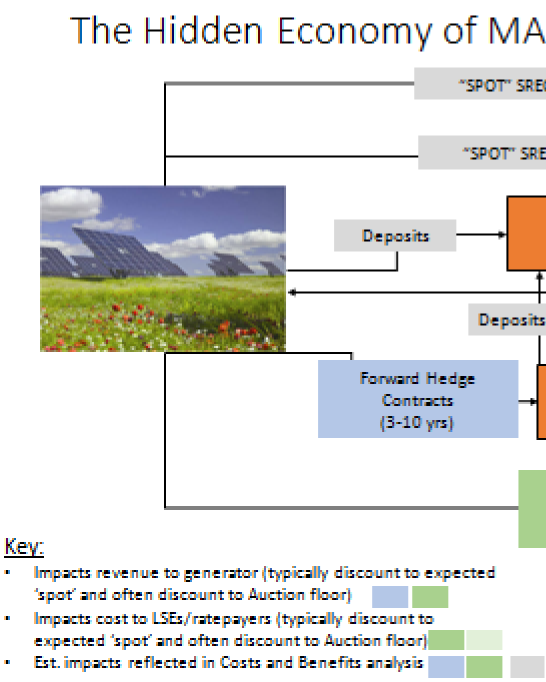
Perspective	Subcategories Accruing as Net Benefits to Some or All With Perspective	Subcategories Accruing as Net Costs to Some or All With Perspective
*Non-Owner Participants **(NOP)***	- N/A	- N/A
*Customer-Generators **(CG)***	- Direct Incentives	- Solar Policy Incremental Admin. and Transaction Costs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

D.4.1 Direct Incentives

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

To calculate the value of SREC payments, it is important to understand the structure of the existing SREC markets, as well as how a hypothetical program (SREC-III) that extends the basic structure of SREC-I and SREC-II to 2025. Figure 76 is an illustration of the main structural flows and features of the Massachusetts SREC market, underscoring the hedging transactions that result in revenues to generators differing from costs to ratepayers.

Figure 76: Schematic Diagram of Hedging Transactions within the SREC Carve-out Market



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

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

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

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

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

Table 88: Direct Incentives Impacts by Perspective

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

D.4.2 Other Solar Policy Compliance Costs

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

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

Table 89: Other Solar Policy Compliance Costs Impacts by Perspective

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

D.4.3 Displaced RPS Class I Compliance Costs

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

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

Table 90: Displaced RPS Class I Compliance Costs Impacts by Perspective

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

D.4.4 Solar Policy Incremental Administrative and Transaction Costs

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

Table 91: Solar Policy Incremental Admin. & Transaction Costs Impacts by Perspective

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

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

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

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

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

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

Table 92: BTM Production within the Billing Month Applicability to Analysis Perspectives

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

D.5.1 Generation Value of On-Site Generation

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

Table 93: Generation Value of On-site Generation Impacts by Perspective

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

D.5.2 Transmission Value of On-Site Generation

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

Table 94: Transmission Value of On-site Generation Impacts by Perspective

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

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

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

Table 95: "Adjusted" Distribution Value of On-site Generation Impacts by Perspective

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

D.5.4 Other Retail Bill Components

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

Table 96: Other Retail Bill Components (Transition, EE, RE) Impacts by Perspective

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

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

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

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

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

Table 97: Net Metering Credits beyond the Billing Month (Including Virtual Net Metering) Applicability to Analysis Perspectives

Perspective	Subcategories Accruing as Benefits	Subcategories Accruing as Costs

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

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

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

Table 98: Offsetting On-site Usage Beyond Current Billing Month Impacts by Perspective

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

D.6.2 Virtual Net Metering

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

Path A is reduced to the value of the wholesale value of electricity. The treatment of net metering credits for virtually net metered systems would be analogous to the treatment of customer-hosted systems.

Table 99: Virtual Net Metering Impacts by Perspective

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

D.6.3 Wholesale Market Sales

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

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

Table 100: Wholesale Market Sales Impacts by Perspective

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

D.6.4 Virtual Net Metering Administrative Costs

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

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

Table 101: VNM Admin Costs Impacts by Perspective

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

D.7 Category V: Electric Market

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

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

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

Table 102: Electric Market Impacts Applicability to Analysis Perspectives

Perspective	Subcategories Accruing as Benefits to Some or All With Perspective	Subcategories Accruing as Costs to All or Some With Perspective

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

D.7.1 Wholesale Market Impacts – Energy

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

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

Table 103: Wholesale Market Price Impacts – Energy Impacts by Perspective

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

D.7.2 Wholesale Market Impacts – Capacity

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

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

Table 104: Wholesale Market Price Impacts – Capacity Impacts by Perspective

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

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

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

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

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

In addition, the analysis described in Section 3.1 revealed that solar PV's electric load carrying capacity (ELCC), which decreases as PV penetration increases and shifts peak hours later into the evening, is substantially higher than the Seasonal Claimed Capacity for intermittent renewables in FCM – the value of which is independent of penetration. As Figure 19 in Section 3.1 shows, solar reduces peak, and thus the ICR, to the extent the peak reduction benefit is not fully captured in solar SCC calculations. The analysis in Section 3.1 also calculates the impact on peak reduction from solar PV as a function of penetration, which is used in these calculations. Thus, this analysis derives both the capacity impacts of distributed solar PV, and the installed capacity reserves (ICR), the net of which is the value of avoided capacity reserve requirements and on-peak line losses (also discussed in Section 3.2 and Section D.7.4).

Table 105: Avoided Generation Capacity Costs (Including Avoided Generation Capacity Reserve Costs) Impacts by Perspective

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

D.7.4 Avoided Line Losses

Line losses represent the generated energy that is lost due to electrical resistance in the process of delivering (i.e. transmitting and distributing) electricity from source to sink. The derivation of loss factors in discussed in Section 3.2. The applicable loss factors are applied to individual cost and benefit components throughout this study, rather than being tallied explicitly as an individual line item. The value of avoided *marginal* losses due to locating generation on the periphery of the distribution system near load is not captured by prices for generation, but accrues broadly to load, and thus to all ratepayers. Thus, the study adjusts many of the costs and benefit subcategories within this analysis using a solar production-weighted line loss formula based on statewide average line loss figures outlined in Table 42 in Section 3.2.

D.7.5 Avoided Transmission Tariff Charges

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

Table 106: Avoided Transmission Tariff Charges Impacts by Perspective

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

D.8 Category VI: Electric Investment Impacts

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

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

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

Table 107: Electric Investment Impacts Applicability to Analysis Perspectives

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

D.8.1 Avoided Transmission Investment – Remote Wind

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

$$\begin{aligned}&Total\ \$/MWh\, Avoided \\ &\quad = (Avoided\ Transmission\,\$/MWh\ \ Allocated\ to\ Load * MA\ Load\ Ration\ Share\ for\ ISO \\ &\quad - NE\ Tariff) * MA\ T\&D\ Loss\ Adjustment\end{aligned}$$

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

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

Table 108: Avoided Transmission Investment - Remote Wind Impacts by Perspective

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

D.8.2 Avoided Transmission Investment – Local

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

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

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

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

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

Table 109: Avoided Transmission Investment – Local Impacts by Perspective

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

D.8.3 Avoided Distribution Investment

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

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

- First, estimates of deferral benefits were taken from a literature review. Seven sources were selected to represent a reasonable range of conditions and methodologies, and an average value was calculated from these sources for the area-wide passive deferral benefit of solar PV, as described more fully in Appendix E.[107] These sources included three case studies of active deferral in particular New England locations and four reports with estimates of passive or area-wide deferral impacts and with adequate detail on their methodologies. Where necessary, the estimates from four of these sources were adjusted to be comparable by applying MA-specific and PV-specific factors.
- Second, to confirm the reasonableness of the average distribution deferral value from the literature, that value was compared against a simplified analysis driven by assumptions about distribution feeder load growth, upgrade costs, solar penetration and coincidence of solar output with feeder load.
- Third, the analysis assumes that the percentage of the state's distribution system to which estimates of "active deferral" are applicable; this is the portion of the system that is growing and so will require new capacity or otherwise provides opportunities to defer distribution investments, estimated to be 30%.[108] This was applied to estimates from the literature review to the simplified analysis in Step 2 to get statewide values.[109]

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

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

where

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

However, if distributed solar PV is installed without integration into planning, the net deferral or avoidance benefits accrue in a rather different manner. While current utility planning assumes limited to no distribution

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

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

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

deferral or avoidance benefit associated with PV in the short run, it can be assumed that over time, localized distribution planning (or the existence of distribution congestion pricing, if applicable) will take the solar into account in advance, leading to a "passive" deferral value that may be quantifiable in the future. While the passive value cannot currently be calculated on a locational basis without similar location-specific deferral values at many smaller, distribution-level nodes (often known as "buses") the analysis calculates the total deferral value (including an estimate of passive deferral value) that can currently be averaged across each EDC service territory.

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

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

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

where

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

and

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

Table 110: Avoided Distribution Investment Impacts by Perspective

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

D.8.4 Avoided Natural Gas Pipeline

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

When new natural gas-fired power plants are built or add to their capacity, added pipeline capacity to serve those plants may be needed (and under current pipeline-constrained conditions in New England, this can be assumed to be the case).

While solar has a lower capacity value during winter peak electricity (which coincides roughly with peak annual gas demand), increased PV capacity can potentially reduce total investment in gas pipeline capacity. These effects could be accentuated as technologies evolve to optimize PV's dependable capacity.

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

Table 111: Avoided Natural Gas Pipeline Impacts by Perspective

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

D.9 Category VII: Externalities and Other

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

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

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

Table 112: Externalities and Other Impacts Applicability to Analysis Perspectives

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

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

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

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

Table 113: Avoided Environmental Costs CO_2, NO_x and SO_x Impacts by Perspective

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

D.9.2 Avoided Fuel Uncertainty

Avoided fuel uncertainty accounts for the costs associated with the risk of a significant change in the price of fuels for electricity generation (specifically natural gas) and the associated costs of fuel hedging contracts and other instruments that can be avoided by solar PV deployment. In the case of solar PV, the value of avoided fuel cost uncertainty would capture the value of price-certain resource compared to a price-uncertain resource. While quantitative analysis of this value is beyond the scope of this study, the factor was recently included in Maine's Value of Solar Study (Clean Power

Research, LLC; Sustainable Energy Advantage, LLC; Perez Richard; Pace Law School Energy and Climate Center, 2015) released in March 2015. The Maine VOSS quantified this value to be $0.037/kWh (on a 25-year levelized basis) at by estimating the cost associated with eliminating long term price uncertainty with procuring the quantity of natural gas displaced by solar PV. To do this, the authors of that analysis calculated the difference between the non-guaranteed and guaranteed price of natural gas to determine the net present value of hedging natural gas purchases. Thus, it appears that this methodology could be utilized in Massachusetts and could represent a significant value in Massachusetts. We have not, however, included this value within this analysis.

Table 114: Avoided Fuel Price Uncertainty Impacts by Perspective

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

D.9.3 Resiliency

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

Table 115: Resiliancy Impacts by Perspective

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

D.9.4 Impact on Jobs

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

D.9.5 Cost-Benefit Impacts by Perspective

Table 116: Impact on Jobs Impacts by Perspective

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

D.9.6 Policy Transition Frictional Costs

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

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

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

Table 117: Policy Transition Frictional Costs Impacts by Perspective

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

APPENDIX E: BACKGROUND ON AVOIDED DISTRIBUTION INVESTMENT

The Avoided Distribution Investment component was described as follows in Appendix D:

- When solar PV is installed near load, some of it will contribute to changes in EDC planning, such that some upgrade investments will be deferred[110] that otherwise would have been needed to provide additional capacity to meet peak growth; this is referred to as "active" deferral and applies to a subset of distribution area(s).
- In contrast, when solar PV is installed without integration into planning, there may be no deferral benefit in the short run, but over time it can nevertheless be assumed that, with experience, planning will take the solar into account, explicitly or implicitly, and this will lead to a "passive" deferral.
- Active and passive deferrals are estimated on the average and combined for the state.[111]

The Avoided Distribution Investment component represented a benefit to two of the four perspectives in this analysis: Non-Participating Ratepayers and Citizens at Large, as summarized in the following table:

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

The Avoided Distribution Investment methodology for this study had four main steps. The approach and assumptions are summarized below for each step.

Step 1: Literature Review

First, estimates of deferral benefits were taken from a literature review.

The following documents attempt to provide an overview of methodologies that have been and/or should be used to estimate the benefits and costs of solar PV for the T&D systems:

- A Regulator's Guidebook: Calculating the Benefits and Costs of Distributed Solar Generation, Interstate Renewable Energy Council, Inc., 2013, pages 26-30;
- Review Of Solar PV Benefit & Cost Studies, 2nd Edition, Rocky Mountain Institute, September 2013 (www.rmi.org/elab_emPower), pages 31-34.
- Minnesota Value of Solar: Methodology, Minnesota Department of Commerce, Division of Energy Resources, by Clean Power Research, April 9, 2014, pages 31, 36, 41.

These methodologies distinguish between T&D capacity benefits and "grid support" impacts. For present purposes, while grid support benefits and costs may become increasingly important over time,

[110] The deferral may last for many years in some cases, particularly where load growth is slow and the DER penetration is substantial, such that in present value terms the "deferral" is equivalent to "avoiding" most of the investment. See note 3.

[111] In addition to deferral of capacity investments, solar PV may have other grid support benefits, such as frequency and voltage regulation. There may also be grid integration costs that are not internalized through the interconnection process. These are complex subjects with changing technologies and rules, but for present purposes, these were not quantified and may be assumed to largely offset each other.

we do not attempt to quantify them here, since there is little information available with which reliable estimates could be made for Massachusetts. We also assume that, to the extent solar interconnection and integration costs are incurred that are not internalized in the cash flows of solar owners, they are offset by grid support benefits.[112] Therefore, T&D capacity benefits are the only T&D benefits that are quantified in this report.

It is widely accepted that, under certain conditions, solar PV may contribute to economic savings by deferring the need to upgrade certain elements of the T&D system. The primary basis for the estimates of deferral benefits used in the present report is a set of economic values reported for case studies and planning studies that are publicly available. Specifically, the following seven sources provide a representative range of estimates.

1. "DG and Distribution Planning: An Economic Analysis for the Massachusetts DG Collaborative," Navigant Consulting, Attachment G to Report to DPU, Jan. 2006
2. "2014 System Reliability Procurement Report," The Narragansett Electric Company d/b/a National Grid, R.I.P.U.C. Docket No. 4453
3. Grid Solar Boothbay: Order Approving Stipulation, State of Maine Public Utilities Commission Docket No. 2011-138, April 30, 2012, Request for Approval of Non-Transmission Alternative (NTA) Pilot Projects for the Mid-Coast and Portland Areas
4. "The Value of Distributed Photovoltaics to Austin Energy and the City of Austin," Clean Power Research, L.L.C., March 17, 2006
5. "The Value of Distributed Solar Electric Generation to New Jersey and Pennsylvania," for Mid-Atlantic Solar Energy Industries Association & Pennsylvania Solar Energy Industries Association, by Perez, Norris & Hoff, Clean Power Research
6. "The Benefits and Costs of Solar Distributed Generation for Arizona Public Service," by Beach & McGuire, Crossborder Energy, May 8, 2013
7. "Evaluating the Benefits and Costs of Net Energy Metering in CA," prepared for The Vote Solar Initiative, Crossborder Energy, January 2013.

The following table compares the most relevant estimates from these seven sources, and shows their average value: $.016/kWh.

[112] This report has not addressed any possible differences between the Policy Paths in the ability to optimize these unquantified costs and benefits, such as by targeting feeders or other locations with relatively low interconnection costs for solar projects or with relatively high grid support benefits.

		Key Metrics from Literature Review		A	B	C	D	E
				T&D Capacity Value (2015 dollars)		Deferral Benefit from PV with Specified DCP (2015 dollars)		
				Potential Deferral		Active Deferral		Statewide
				$/kW or $/kVa	$/kW-year (not PV)	$/kW-year of PV	$/kWh of PV	$/kWh of PV
				Blue= source value Green= calculated value using assumptions as needed				
1	**MA**	DG and Distribution Planning: An Economic Analysis for the Massachusetts DG Collaborative, Navigant Consulting, Attachment G to Report to DPU, Jan. 2006	2006	$35	$5	$8	$0.007	**$0.002**
2	**RI**	2014 System Reliability Procurement Report, The Narragansett Electric Company d/b/a National Grid, R.I.P.U.C. Docket No. 4453	2014			$49	$0.038	**$0.012**
3	**ME**	Grid Solar Boothbay: Order Approving Stipulation, 2012	2012			$281	$0.220	**$0.066**
4	**TX**	The Value of Distributed Photovoltaics to Austin Energy and the City of Austin, Clean Power Research, L.L.C., March 17, 2006	2006	$1,516	$64	$31	$0.025	**$0.007**
5	**NJ & PA**	The Value of Distributed Solar Electric Generation to New Jersey and Pennsylvania, for Mid-Atlantic Solar Energy Industries Association & Pennsylvania Solar Energy Industries Association, by Perez, Norris & Hoff, Clean Power Research	2012					**$0.003**
6	**AZ**	The Benefits and Costs of Solar Distributed Generation for Arizona Public Service, by Beach & McGuire, Crossborder Energy, May 8, 2013	2013					**$0.002**
7	**CA**	Evaluating the Benefits and Costs of Net Energy Metering in CA, prepared for The Vote Solar Initiative, Crossborder Energy, January 2013	2012		$55 (SCE) $77 (SDG&E) ~$80 (PG&E)			**$0.022**
							Average of values above	**$0.016**

One other study appeared too late to add into this average: "Value of Distributed Generation, Solar PV in Massachusetts," Acadia Center, April 2015. Its estimate of statewide deferral value for south-facing solar in Massachusetts -- $.018/kWh -- was only slightly above the average of the seven sources above, so it wouldn't have significantly changed the result.

Other sources provided relevant estimates of distribution investments or capital costs that are potentially deferrable (e.g., load or capacity upgrades), but stopped short of estimating deferral impacts.

As can be seen from the table, the literature includes a wide range of estimates. Also, different metrics are reported that are often not directly comparable. Where necessary (see green values in table), values have been converted to comparable units of dollars per solar kW and cents per solar kWh, using assumptions for solar capacity factor (for column D) and ELCC (solar match, for column E) that are consistent with the rest of the present project. Values have also been adjusted to 2015 dollars, using a 2.5% annual escalator.

Step 2: Simplified Generic Worksheet of Distribution Deferral

To confirm the reasonableness of the $.016/kWh average distribution deferral value from the literature, that value was compared against a simplified generic worksheet driven by a basic set of assumptions about distribution feeder load growth, upgrade cost, solar penetration and coincidence of solar output with feeder load. This worksheet illustrates the range of potential deferral benefits as these assumptions are varied, and provides additional confidence in the deferral value from the literature in step 1. The following table illustrates a scenario with a deferral from 2018 to 2037, which leads to a 56% savings in the present value of distribution investment required. The assumptions that lead to this scenario are listed below.

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
				Upgrade cost incurred in year when needed							
		Load as % of Capacity		Year of Need for Upgrade		Cost of Upgrade ($000)	Capital Cost & Timing of Upgrades ($000)		Amortized Cost of Upgrades ($000), based on 30-year NPV		
		Existing	with DER	Existing	with DER		Upgrade, No DER	Upgrade, with DER	Upgrades, No DER	Upgrades with DER	Annual Savings ($000)
0	2015	98.0%	83.0%			$250			100%	44%	56%
1	2016	98.7%	83.7%	0	0	256			$	$	$
2	2017	99.5%	84.5%	0	0	263			$	$	$
3	2018	100.2%	85.2%	2018	0	269	269		$31	$14	$18
4	2019	101.0%	86.0%	0	0	276			$31	$14	$18
5	2020	101.7%	86.7%	0	0	283			$31	$14	$18
6	2021	102.5%	87.5%	0	0	290			$31	$14	$18
7	2022	103.3%	88.3%	0	0	297			$31	$14	$18
8	2023	104.0%	89.0%	0	0	305			$31	$14	$18
9	2024	104.8%	89.8%	0	0	312			$31	$14	$18
10	2025	105.6%	90.6%	0	0	320			$31	$14	$18
11	2026	106.4%	91.4%	0	0	328			$31	$14	$18
12	2027	107.2%	92.2%	0	0	336			$31	$14	$18
13	2028	108.0%	93.0%	0	0	345			$31	$14	$18
14	2029	108.8%	93.8%	0	0	353			$31	$14	$18
15	2030	109.6%	94.6%	0	0	362			$31	$14	$18
16	2031	110.4%	95.4%	0	0	371			$31	$14	$18
17	2032	111.3%	96.3%	0	0	380			$31	$14	$18
18	2033	112.1%	97.1%	0	0	390			$31	$14	$18
19	2034	112.9%	97.9%	0	0	400			$31	$14	$18
20	2035	113.8%	98.8%	0	0	410			$31	$14	$18
21	2036	114.6%	99.6%	0	0	420			$31	$14	$18
22	2037	115.5%	100.5%	0	2037	430		430	$31	$14	$18
23	2038	116.4%	101.4%	0	0	441			$31	$14	$18
24	2039	117.2%	102.2%	0	0	452			$31	$14	$18
25	2040	118.1%	103.1%	0	0	463			$31	$14	$18
26	2041	119.0%	104.0%	0	0	475			$31	$14	$18
27	2042	119.9%	104.9%	0	0	487			$31	$14	$18
28	2043	120.8%	105.8%	0	0	499			$31	$14	$18
29	2043	121.7%	106.7%	0	0	512			$31	$14	$18
30	2044	122.6%	107.6%	0	0	524			$31	$14	$18
				Sum			269	430	878	388	490
				Net Present Value			**235**	**104**	**356**	**157**	**199**
				Levelized Values					27	10	15
				Upgrade and Savings Percentages					**100%**	**44%**	**56%**

The assumptions which lead to this deferral from 2018 to 2037 are listed below, including a distribution feeder load growth rate of 0.75%/year, an upgrade cost of $250/kW, penetration of 15% for solar (or a combination of solar and other Distributed Energy Resources (DER), and coincidence of 33% between solar output and feeder load (equivalent to the ELCC, but at the distribution level; see Section 3.1 for a chart of this value over time). The following table also summarizes the results of this deferral scenario in present value terms:

- a 56% savings in the present value of distribution investment required, and
- a distribution deferral value of $.055/kWh for PV on this feeder (for "active deferral") from this simple model.[113]

Two additional calculations appear at the bottom of this table, which are described in Steps 3 and 4 below:

- a statewide (or "passive") distribution deferral value of $.016/kWh (which is nearly the same as the average from the literature in Step 1), after assuming (per Step 3 below) that 30% of the feeders statewide would have an opportunity for such an active deferral, and
- a net statewide distribution deferral value of $.008/kWh after assuming that deferral would be feasible on 50% of the feeders despite technical challenges discussed in Step 4 below.

Illustrative Model of Upgrade Deferral by DER (4/27/15)

Inputs: (input cell)

	Inputs	
1	Feeder Capacity (MW)	.0
2	Current Load %	98%
3	Current Load (MW)	1.0
4	Peak Load Growth	0.750%
5	New DER as % of Feeder Load	15.0%
6	DER Reduction of Load (MW)	0.147
7	Upgrade Cost/kW*	$250.00
8	Upgrade Capacity	100%
9	Upgrade Capacity (MW)	1.0
10	Cost ($000, $/kW-yr)	$250
11	Escalation of Upgrade Cost	2.5%
12	Discount Rate/WACC	7.0%
13	Carrying Chg/ Fixed Chg Rate (see sheet)	13.3%
14	Solar DCP (Distrib Contrib as % of PV kW)	33%
15	Solar MW (AC)	.445
16	Solar MWh/yr	567
17	Deferral years	19
18	MWh in deferal years	0,771

Results:

Present Value Analysis:	Capital Costs: Upgrade, No DER	Capital Costs: Upgrade, with DER	Annual Costs: Upgrade, No DER	Annual Costs: Upgrade, with DER
Upgrade Cost ($000)	$220	$97	$333	$147
Savings ($000)		$123		$186
Savings (% reduction)		56%		56%
Savings $/kW of DER		$834		$,262
Savings $/kW of Solar		$275		$,043

	This Run	Weighted*
Cumulative Savings $/kWh of Solar	$0.0617	$0.0548

** Weighted by load growth and DER penetration*

	Active	% of load on feeders with growth	Statewide
Distribution Deferral for PV across territory from model ($/kWh)	$0.0548	30%	$0.0164
Average of 5 values from the literature ($/kWh)	$0.0542	30%	$0.0163
Weighted/selected results	$0.0542		$0.0163
Adjustment for technical issues			50%
Assumed Distribution Deferral for PV ($/kWh)			$0.0081

Step 3: Opportunities to Defer Distribution Investments

[113] The amortized Annual Savings in column (10) are divided by the cumulative solar kW installed each year to defer the investment, and then the resulting $/kW annual savings are divided by solar output each year and levelized for this active deferral value of $.055/kWh.

We make an assumption for the percentage of the state's distribution system to which estimates of "active deferral" are applicable; this is the portion of the system that is growing and so will require new capacity or otherwise provides opportunities to defer distribution investments.[114] We have used 30 percent as a placeholder assumption for this factor. This was applied to estimates from four of the literature sources and to the results from the worksheet in Step 2 to get a statewide distribution deferral value of $.016/kWh.[115]

Step 4: Technical Factors to Achieve Deferral

There are a number of factors that may be required in order for distribution planners to sufficiently rely upon solar DG to actually achieve a deferral of upgrade investments. Some of these factors may affect the physical availability of PV to reduce load under challenging conditions, such as following power quality disturbances and grid outages; planning lead time is also a factor.

These factors include:

- IEEE 1547 standards requires DG to trip for low voltage and other disturbances, and low-voltage ride-through may be incompatible with anti-islanding protection;
- Planners can't count on PV to be on-line instantly as power is restored after outage; and,
- Physical assurance may be needed to keep load off the distribution system if the solar goes down.

These issues are important and should be addressed through further R&D, pilot testing and policy development. This will lead to better information to estimate their impact on the benefits and costs of solar for the T&D system. In the meantime, we simply apply a factor for the percentage of PV that can be counted upon for distribution deferral through the use of physical assurance, storage, smart inverters with ride-through, linked demand response and/or other means. We have used 50 percent as a placeholder assumption for this factor, resulting in a net statewide distribution deferral value of $.008/kWh.

Results

The result for steps 1 through 3 for this illustration was $.016 average statewide value of Avoided Distribution Investment per kWh of solar PV. After applying the 50% factor from Step 4, the net value = $.008/kWh. The modeling for this study replaced the static assumption for peak coincidence described above with the with the solar penetration-dependent value for each year, calculated as discussed in Section 3.1.

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

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

APPENDIX C: Task 4 PowerPoint Presentations

Consulting Team

Presentation & Discussion of Preliminary Results and Candidate Policy Paths

Massachusetts Net Metering Task Force

Mtg #4 - February 12, 2015

PEREGRINE ENERGY GROUP

Sustainable Energy Advantage, LLC

MEISTER CONSULTANTS GROUP

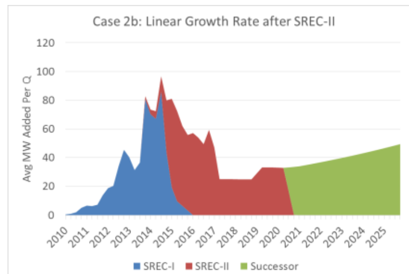
La Capra Associates

TASK 4

PROVIDE A RANGE OF OPTIONS TO REACH THE 1600 MW GOAL… AND BEYOND

Task 4: Objective

- Based on research, analysis, findings from Tasks 0, 1, 2 & 5, input from Task Force, other stakeholders & public…
- *"Provide a range of options for appropriate structures for providing support to reach the 1600 MW goal & provide opportunity for additional development."*
- Select a subset to be analyzed, compared in cost/benefit analysis to Current Policy
  - SREC Carve-out + Current Net Metering Regime, 1600 MW goals, Current NM caps
  - ***To allow for more robust comparisons between options, DOER considering expanding modeling (for benchmarking purposes) of hypothetically extending current regime to 2500 by 2025 under Net Metering regime TBD***



(3)

Outline

- Key assumptions
- Options to adjust/modify current net metering &/or solar incentives capable of reducing costs without reducing benefits
- Alternative structures for solar and/or net metering policy
  - Categories
  - Dimensions
  - Options
  - Criteria - for what might be deemed 'appropriate' or 'desirable'
  - Stakeholder goals
  - Analysis
- Screen and group policy 'elements' into (up to 6) '**Policy Paths**'

(4)

Key Assumptions

- Not constrained to 1600 MW by 2020
  - 1600 not max
  - Nothing magic about either MW amount or date by which a target is reached
- On the table:
  - No change
  - All new
  - Modifications
  - Hybrids
- Changes generally presume grandfathering past investments

(5)

Options to adjust/modify current net metering &/or solar incentives (1)

Capable of reducing costs without reducing benefits

- No Brainers
  - Refunding (percentage of) ACP pmts. to ratepayers
    - (model: recent CT PA 13-303)
  - EDCs participation in auctions.
    - Require/consider/analyze/justify why not/have DPU consider prudence of abstaining?
    - Systematic abstention impacts cost of EDC purchases *and* spot market prices for all
  - Shift incentives (greater SREC factors) to favor location "to support & enhance needs of distribution system"
    - as also suggested for LREC/ZREC program in recent CT draft IRP (p. 113)
  - EDCs Monetize FCM benefits. Options:
    - Options: revenue flow-back to customers (while mitigating EDC exposure to performance risk); EDCs auction FCM rights to others; or let system owners keep rights

(6)

Options to adjust/modify current net metering &/or solar incentives (2)
Capable of reducing costs without reducing benefits

- Other (more involved) options Include:
  - Long-Term contracting within SREC program
    - NGRID competitive pilot proposal w/in SREC (2013)
    - model: MA 83A or NJ EDC programs
    - *Note: may have modest distribution effects on benefits*
  - Firm the floor?
    - Source of $?
    - Masking market price signals, impact on market, etc. (stimulating build when surplus?)
  - Stretch SREC life to 15 yrs and lower cap & floor?
    - More directly comparable to CT ZREC, RI Renewable Energy Growth and DG Standard Contract prices
    - Can prices converge to Class I more quickly?

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(7)

Alternative Structures for Solar and/or Net Metering

Treating Different Solar PV Categories Differently

- 'Large' vs. 'Small' Distributed Generation; Utility-scale (wholesale)
- Bifurcating treatment of large and small may be desirable
  - Rationale – sophistication/expertise, transaction cost, efficiency
  - Several studies have concluded different approaches preferable
  - Of examples studies (T1) → many take different approach to large vs. small, or DG vs. wholesale
    - CA, NY, RI, VT, CT, NJ, MA, DE;
    - VOST has only been used for small
    - MA (historically and now)

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(9)

Dimensions Considered

- Solar Incentive (Small vs. Large)
- Installation Diversity/Encouraging targeted types
- Net Metering Approach (Projects sized to load, oversized/VNM)
- Timing of Transitions
- Targets/Constraints
- Quantity target/timeline (set, or for analysis)

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(10)

Key:
- Already considered
- Unlikely to be politically acceptable
- Identified of interest by TF
- Other options to consider

OPTIONS: SOLAR INCENTIVES

Small Projects (unsophisticated)

- SREC
- SREC-modified
- Financing within SREC (NJ/PSE&G)
- Standard Offers (SO):

Structure → Price Formation ↓	PBI/SO*	Upfront Cost Reduction (rebate)/SO
Administratively-set price	RI REG (small)	CT (res-HOPBI)
Competitive benchmark	CT ZREC (small)	
DBI pricing mechanism	CA (small C)	NY (small), CA (Small R)

- PBI/Solicitations (aggregated vs. individual)
- None

Large/Utility-Scale Projects (conducive to competition)

- SREC
- SREC-modified
- PBI with long-term fixed price contract/tariff
  - **Solicitations**: e.g. CT ZREC, RI REG, DE, VT, NY, NJ EDC
  - Adjustable Block Incentive (ABI) (CA ReMAT)
  - PBI/DBI (CA)
- EPBI/SO/Rebate
  - (NY: hybrid DBI w/3-yr PBI)
- Solar avoided cost /LT EDC purchase obligation
- None

11

Installation Distribution: Diversity/Encouraging Targeted Types

- Un-stratified
  - head to head, low price (or premium) wins
- Limits to larger projects, or not?
- Stratified by size (sub-tiers of specified size)
- Stratified by type (like SREC-II)
- MW distributed by EDC pro-rata to load
  - like CT ZREC, CSI
- What Favored (disfavored)?
  - Brownfields/LFG
  - Municipal
  - Aggregate (common ownership, municipalities)
  - Community-Shared Solar (CSS)
  - Low-income
  - Support/enhance distribution system
  - Host-owned vs. 3rd-party-owned
- How favored?
  - SREC Factors
  - Co-incentives (e.g. SBC pmts)
  - Segmentation of incentive, or competitive points
- Design choice can have the effect of…
  - favoring national/large players, or maintaining a role for local firms too?
  - Impacting degree to which policy supports adding permanent local jobs

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(12)

OPTIONS: NET METERING APPROACH
(CREDIT FOR ON-SITE PRODUCTION)

Key:
- Already considered
- Unlikely to be politically acceptable
- Identified of interest by TF
- Other options to consider

Net Metering Credits (projects sized to load)	Virtual Net Metering Credits (Oversized)

• As-is - *With or without caps?*
• NM netted from solar incentive
• Value of Solar Tariff (VOST)
  • (Small only?)
  • alone or with other incentives?
• Separate rate class Modified w/rate changes, 1 or more of:
  • Min. Bill
  • Shift D rates to more demand-based revenue
  • Demand charges on outgoing flow
• None
	• As-is - *Capped at what level?*
	• NM netted from solar incentive
	• Limited to Aggregate
	  • municipal & other common ownership
	• Targeted to CSS
	• Modified w/rate changes, 1 or more of:
	  • Min. Bill
	  • Shift D rates to more demand-based revenue
	  • Demand charges on outgoing flow
	  • Remove D charge from credit for Class II and III VNM public sector and CSS projects
	• None

13

Options: Timing of Transitions

Key:
- Already considered
- Unlikely to be politically acceptable
- Identified of interest by TF
- Other options to consider

1. Set date*
   a) End of ITC (new program @ 1/1/2017)
   b) Other
2. Set MW*
   a) Post-1600 MW
   b) Other
3. End of SREC-II as currently defined*
4. End of NM caps
   a) Current
   b) Expanded
   - *Practical barrier: EDCs will hit NM caps at different times*

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(14)

Options: Targets/Constraints

- MW Goal with Timeline
  - Firm timeline (e.g., RI, VT)
  - Soft timeline (e.g., MA, CA ReMAT (hybrid?))
- MW Goal without Timeline (e.g., DBI in NY, CA)
- Budget-defined & limited (quantity moves inversely with price) (e.g., CT ZREC)
- Unconstrained
  - (e.g., avoided cost, VOST, SO/FIT without caps, NM/VNM-only w/o caps, with TVRs)

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(15)

Quantity Target/Timeline (set, or for analysis)

- If applicable
- MW Goal or Target, e.g.:
  - 2500 MW
  - Other
- Timeline, e.g.:
  - 2020
  - 2025
  - other

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(16)

Policy Paths

- Comprised by selecting a choice from each menu
  - Thousands of possible combinations
- Aim to have a limited, but diverse and distinct set of alternatives for consideration
  - To highlight major differences
  - Doesn't preclude fine-tuning later
- Goal (from scope/budget):
  - Team to ID 6 paths
  - TF to select from those a subset for benefit and cost analysis
  - Analysis of 2 scenarios in Consultant scope/budget
    - *Additional analysis requires more budget and time*

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(17)

Proposed 'Policy Paths'

Path #/Name:	Description
1. SREC Program Modifications incl. LT Contracting Pilot	Keep the current incentive model but make adjustments that reduce costs while maintaining benefits
2. Minimize Ratepayer Impacts	Incentives set based on results of regular competitive solicitation to ensure only the most cost effective installations are built, minimizing ratepayer impacts
3. Orderly Market Evolution	Offer declining block incentive (DBI) to create market certainty and lower cost of financing while transitioning away from state incentives
4. Sustained Growth Adapting to Market Changes	Incentives rates automatically adjust (up or down) to market conditions through volume-based price setting
5. Maximize federal incentives w/ Managed Growth Boost + Sustainable Growth	Incentives rates automatically adjust (up or down) to market conditions through volume-based price setting Add tailored incentive for "managed growth" sector to capture max federal incentives before 2017
6. Reliability First	Target PV to support & enhance needs of the distribution system Max system owners contributions the distribution system
7. Maximize Installed MW within Defined Ratepayer Impact	Apply measures to drive down cost premium, while limiting outlays to preset budget

1. SREC Program Modifications incl. LT Contracting Pilot

Description	Keep the current incentive model but make adjustments that reduce costs while maintaining benefits
Analog	• Mass. SREC-II Program, N.J. PSE&G loan program, proposed National Grid SREC pilot (2013)
Solar Small	• Current SREC-II Model; plus Implement utility SREC performance-based (PBI) incentive standard offer program with REC resales for a portion of the market
Solar Large	• Current SREC-II Model; plus Implement utility SREC long-term contracting program through PBI solicitations with REC resales for a portion of the market
Distribution	• Increase SREC factor for locations that enhance grid reliability
Net Metering	• As-is, uncapped
Virtual Net Metering	• As-is
NM Caps & Timing of Transitions	• Net metering cap as-is • Transition target: 1/1/16 (or ASAP
Targets, Constraints	• MW goal with soft timeline
Quantity Target, Timeline	• 1600 MW by 2020
Other Features	• Refund Alternative Compliance Payments (ACP) to ratepayers • Promote utility participation in SREC auction • Require monetization of forward capacity market (FCM) revenues
Other Potential Options	• Firm the SREC price floor • Extend SREC life to 15 years

2. Minimize Ratepayer Impacts

Description	Incentives set based on results of regular competitive solicitation to ensure only the most cost effective installations are built, minimizing ratepayer impacts
Analog	• Rhode Island Renewable Energy Growth, Connecticut ZREC
Solar Small	• Performance-based incentive (i.e., $/kWh produced) • Incentive rates indexed to large-scale competitive solicitation rates • First-come, first-served access (i.e., standard offer) • Rates based on bundled electricity value and RECs
Solar Large	• Performance-base incentive (i.e., $/kWh produced) • Set through competitive solicitations 3X per year • Rates based on bundled electricity value and RECs
Distribution	• Limited differentiation between installation types; maximize economies of scale
Net Metering	• Reduce incentives by net metering credit compensation, + minimum bill
Virtual Net Metering	• Reduce incentives by net metering credit compensation, + minimum bill
NM Caps & Timing of Transitions	• Remove net metering caps before transition • Transition target: 1/1/17 (end of federal incentives)
Targets, Constraints	• MW goal with timeline (annual targets)
Quantity Target, Timeline	• 2,500 MW by 2025

3. Orderly Market Evolution

Description	Offer declining block incentive (DBI) to create market certainty and lower cost of financing while transitioning away from state incentives
Analog	• California Solar Incentive (CSI), New York Megawatt Block Program
Solar Small	• Rebates (i.e., upfront payments) • First-come, first-served (i.e., standard offer) • Rates set via declining block incentive (DBI)
Solar Large	• Performance-based incentive (i.e., $/kWh produced) or hybrid rebate/performance-based incentive • First-come, first-served (i.e., standard offer) • Rates set via declining block incentive (DBI)
Distribution	• Separate incentive pools for each utility • Incentive adders for different system types/locations
Net Metering	• Keep current net metering rates but add minimum bill or transition to Value of Solar Tariff (VOST)
Virtual Net Metering	• Limit to aggregate net metering and community shared solar • Keep current net metering rates but add minimum bill or transition to Value of Solar Tariff (VOST)
NM Caps & Timing of Transitions	• Remove net metering caps before transition • Transition target: end of SREC-II or 1/1/17 (end of federal incentives)
Targets, Constraints	• MW goal with fixed-quantity blocks, no firm timeline
Quantity Target, Timeline	• 2,500 MW at program close

4. Sustained Growth Adapting to Market Changes

Description	**Incentives rates automatically adjust (up or down) to market conditions through volume-based price setting**
Analog	• California Renewable Market Adjusting Tariff (ReMAT)
Solar Small	• Rebates (i.e., upfront payments) • First-come, first-served (i.e., standard offer) • Adjustable Block Incentive with incentive pricing adjusting (up or down) to program participation levels
Solar Large	• Performance-base incentive (i.e., $/kWh produced) • First-come, first-served (i.e., standard offer) • Adjustable Block Incentive with incentive pricing adjusting (up or down) to program participation levels
Distribution	• Separate incentive pools for each utility • Incentive adders for different system types/locations
Net Metering	• Keep current net metering rates but add minimum bill or transition to Value of Solar Tariff (VOST)
Virtual Net Metering	• Limit to aggregate net metering and community shared solar • Keep current net metering rates but add minimum bill or transition to Value of Solar Tariff (VOST)
NM Caps & Timing of Transitions	• Remove net metering caps before transition • Transition target: end of SREC-II or 1/1/17 (end of federal incentives)
Targets, Constraints	• MW goal with fixed-quantity blocks, soft timeline
Quantity Target, Timeline	• 2,500 MW at program close

5. Maximize federal incentives w/ Managed Growth Boost + Sustainable Growth

Description	**Incentives rates automatically adjust (up or down) to market conditions through volume-based price setting** **Add tailored incentive for "managed growth" sector to capture max federal incentives before 2017**
Analog	• California Renewable Market Adjusting Tariff (ReMAT)
Solar Small	• Rebates (i.e., upfront payments) • First-come, first-served (i.e., standard offer) • Adjustable Block Incentive with incentive pricing adjusting (up or down) to program participation levels
Solar Large	• Before 1/1/2017: Administratively set performance-based incentive below SREC price floor for "managed growth" sector (i.e., large, greenfield solar) • After 1/1/2017: Performance-base incentive (i.e., $/kWh produced) • After 1/1/2017: First-come, first-served (i.e., standard offer) • After 1/1/2017: Adjustable Block Incentive with incentive pricing adjusting (up or down) to program participation levels
Distribution	• Separate incentive pools for each utility • Incentive adders for different system types/locations • Before 1/1/2017: Tailored incentive for "managed growth" sector
Net Metering	• Keep current net metering rates but add minimum bill. or transition to Value of Solar Tariff
Virtual Net Metering	• Limit to aggregate net metering and community shared solar • Keep current net metering rates but add minimum bill or transition to Value of Solar Tariff
NM Caps & Timing of Transitions	• Remove net metering caps before transition • Transition target: end of SREC-II or 1/1/17 (end of federal incentives) • Provide managed growth incentive ASAP
Targets, Constraints	• MW goal with fixed-quantity blocks, soft timeline
Quantity Target, Timeline	• 2,500 MW at program close

6. Reliability First

Description	**Target PV to support & enhance needs of the distribution system** **Max system owners contributions the distribution system**
Analog	• Connecticut ZREC; Mass. H4185
Solar Small	• Performance-based incentive (i.e., $/kWh produced) • Incentive rates indexed to large-scale competitive solicitation rates • First-come, first-served access (i.e., standard offer) • Rates based on bundled electricity value and RECs • Incentive adder for systems in designated reliability support grid zones
Solar Large	• Performance-base incentive (i.e., $/kWh produced) • Set through competitive solicitations 3X per year • Rates based on bundled electricity value and RECs • Incentive adder for systems in designated reliability support grid zones
Distribution	• Limited restrictions of system size • Geographic targeting for enhances distribution system support • Separate incentive pools for each utility
Net Metering	• Add minimum bill or shift transmission and distribution charges to demand-based charges
Virtual Net Metering	• Sunset virtual net metering • Implement buy-all, sell-all compensation
NM Caps & Timing of Transitions	• Remove net metering caps before transition • Transition target: 1/1/17 (end of federal incentives)
Targets, Constraints	• Total MW limited by pre-defined program budget • 2/3 of budget targeted to specific grid reliability regions
Quantity Target, Timeline	• Whatever budget supports by program 2025

7. Maximize Installed MW within Defined Ratepayer Impact

Description	Apply measures to drive down cost premium, while limiting outlays to preset budget
Analog	• Connecticut ZREC; Rhode Island DG Growth Program
Solar Small	• Performance-based incentive (i.e., $/kWh produced) • Incentive rates indexed to large-scale competitive solicitation rates • First-come, first-served access (i.e., standard offer) • Rates based on SRECs only
Solar Large	• Performance-base incentive (i.e., $/kWh produced) • Set through competitive solicitations 3X per year • Rates based SRECs only for net metered systems; SRECs and energy for virtual net metered systems
Distribution	• Incentives stratified by size
Net Metering	• As-is or add minimum bill
Virtual Net Metering	• Sunset virtual net metering • Implement buy-all, sell-all compensation
NM Caps & Timing of Transitions	• Remove net metering caps before transition • Transition target: 1/1/17 (end of federal incentives)
Targets, Constraints	• Total MW limited by pre-defined program budget
Quantity Target, Timeline	• Whatever budget supports by program 2025

Note on Finalizing Policy Paths

- Installation Diversity Options
  - Design features to support diversity of installation types, sizes, participants, installers while encouraging optimal location… **Can be superimposed upon most other paths**
- The following can be altered under most of the paths, a set of choices that still must be specified for any C/B modeling
  - Timing of Transitions
  - Targets/Constraints
  - Quantity Target/Timeline

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Summary of Survey Results on Candidate Policy Paths

Massachusetts Net Metering Task Force
Mtg #5 - March15 2015

PEREGRINE ENERGY GROUP · Sustainable Energy Advantage, LLC · MEISTER CONSULTANTS GROUP · La Capra Associates

Response Overview

Responses Received from:

Member
Angie O'Connor, DPU Chair; Task Force Co-Chair
Benjamin B. Downing, Senator
Eric J. Krathwohl, Rich May, P.C.
Liam Holland
Paul Brennan, Attorney General's Office
David Colton, Easton Town Administrator
Robert Rio, Associated Industries of Massachusetts
Charles Harak, National Consumer Law Center
William Stillinger, SEBANE
Fred Zalcman, SunEdison and Solar Energy Industries Association
Janet Besser, New England Clean Energy Council
Larry Aller, Next Step Living
Lisa Podgurski, International Brotherhood of Electrical Workers Local 103
Camilo Serna, Eversource

DPU Included the Following Disclaimer in ALL responses

(omitted from summary for readability)

- The Department seeks to promote solar growth while protecting the interests of ratepayers. The Department's choices for modeling preferences in this survey do not reflect the Department's preferences for any particular option as a final recommendation to the legislature. Rather, the options chosen have been selected in order to compare diverse policy elements that differ from the base case model. Furthermore, the selection of "Top Choice" and "Second Choice" does not indicate the Department's preference of one option over the other. Rather, these are the options among those presented that the Department suggests be considered in modeling to compare diverse policy elements.

Question 2: Preferred Complete Policy Path

Defined Path	Responses
1. SREC Program Modifications incl. LT Contracting Pilot	0
2. Competitive Solicitations	1 (Brennan)
3. Orderly Market Evolution	2 (O'Connor, Harak)
4. Sustained Growth Adapting to Market Changes	1 (Colton)
5. Maximize federal incentives w/ Managed Growth Boost + Sustainable Growth	1 (Krathwohl)
6. Prioritize Distribution System	0
7. Maximize Installed MW within Defined Budget	0
No Opinion	1 (Fisher)

Combination Paths	Responses
2. Competitive Solicitations + 4. Sustained Market Growth	1 (Holland)
3. Orderly Market Evolution + 4. Sustained Growth Adapting to Market Changes	5 (Aller, Stillinger, Podgurski, Besser, Zalcam)
2. Completive Solicitations + 3. Orderly Market Evolution	1 (Rabinowitz)
2. Competitive Solicitation + 6. Prioritize Distribution System	1 (Rio)
Other: Competitive process with defined budget	1 (Serna)

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Question 2 Responses

Primarily the "sustained growth adapting to market changes" model for rooftop/smaller systems associated with onsite load. The "competitive solicitations" model for "large" projects, especially those unaffiliated with load at or near the facility. Modifying both to some degree in order to capture benefits of federal tax incentives. Modifying both market segments in order to incentive solar development where they support and enhance needs of distribution system. (Holland)

Similar to #4, with the following modifications: A combination of 'sustained growth adapting to market changes' and 'orderly market evolution' with the following characteristics: a MW block program with medium to long-term visibility on future incentive levels that are able to react (up or down) to market signals based on known and transparent formulas, with the goal of eventually declining to establish a self-sustaining market, with no incentives.-Different definitions for small vs. large solar segments, with no distinction based on behind the meter or not, just a delineation based on size: *<1MW AC: Small, Over 1MW AC: Large *Virtual net metering is not changed from existing policy *Minimum bill is sent to DPU for consideration as a rate case, with limitation of maximum value being no more than $10 at any point in the future *Any "value of solar" analysis drives a "value of solar credit", rather than a "value of solar tariff" - perhaps a minor point, but may be important for tax purposes. (Aller)

A combination of 'orderly market evolution' (3) and 'sustained growth adapting to market changes' (4) with the following characteristics: a MW block program with medium to long-term visibility on future incentive levels that generally decline overtime but are able to react (up or down) to market signals based on known and transparent formulas. In addition I ask that the consultants consider the merits of the proposal submitted by a number of solar advocates to the task force on February 20, 2015 titled "Fair Solar Policy Framework". (Stillinger)

A combination of 'sustained growth adapting to market changes' and 'orderly market evolution' with the following characteristics: a MW block program with medium to long-term visibility on future incentive levels that generally decline overtime but are able to react (up or down) to market signals based on known and transparent formulas. (Podgurski)

A combination of 'sustained growth adapting to market changes' and 'orderly market evolution' with the following characteristics: a MW block program with medium to long-term visibility on future incentive levels that generally decline overtime but are able to react (up or down) to market signals based on known and transparent formulas. (Besser)

A combination of 'sustained growth adapting to market changes' and 'orderly market evolution' with the following characteristics: a MW block program with medium to long-term visibility on future incentive levels that generally decline overtime but are able to react (up or down) to market signals based on known and transparent formulas. (Rever/Zalcam)

Orderly Market Evolution - declining block, modified as indicated by the responses to the remaining questions in this survey. (O'Connor)

National Grid fully supports competitive solicitations for large-scale solar installations within a defined budget in order to contain costs for electricity customers. Such an approach will automatically allow the price paid for solar output to adjust to the market conditions and tax incentives available. This could be paired with either a Declining Block Incentive or cost-based standard PBI (with variations as appropriate by size and location) for smaller solar installations, as consistent with the models in Rhode Island and New York. Other aspects of a preferred policy path would be to enable and appropriately incent solar owners to provide grid support services (such as voltage support or load relief), when possible, and a rapid, orderly transition to the new model. (Rabinowitz)

Eversource continues to emphasize that any selected policy path needs to accomplish the following goals:* Ensure existing net metering and virtual net metering rules are replaced with a new rate design that properly recognizes today's environment and ensures the principle of rate equity among customers.* Ensure solar incentives are set through competitive and transparent processes.* Ensure Massachusetts is not paying above market costs for solar, especially compared to other states in the region.* Set budgets to provide transparency regarding the investment in solar development in Massachusetts. (Serna)

If I had to chose of the paths it would be 2 - Competitive Solicitations and 6 - Prioritize Distribution. However a far more preferred approach is to return to a market where solar is valued exactly what it is worth. For instance, ideally, solar customers would only get credit for the kWh they are avoiding at the time they are avoiding, while still paying for T&D. There would be variable rates throughout the day based on how much power the competition would be - which is the marginal cost of power. This could be done with smart meters or based on some averages until smart meters become common. It is odd that the DPU is moving to TVR when a basic service customer purchases power, but when it comes to selling power back to the grid, the person gets basic service rates no matter the time of day. Eliminating the T&D from the net metering would avoid minimum bills since the person would be paying for T&D and would still have an incentive to use less. There could still be some variation with regards to locational pricing. In absence of that however, 2 and 6. The proponents keep saying the costs have come down but the subsidies still remain high. (Rio)

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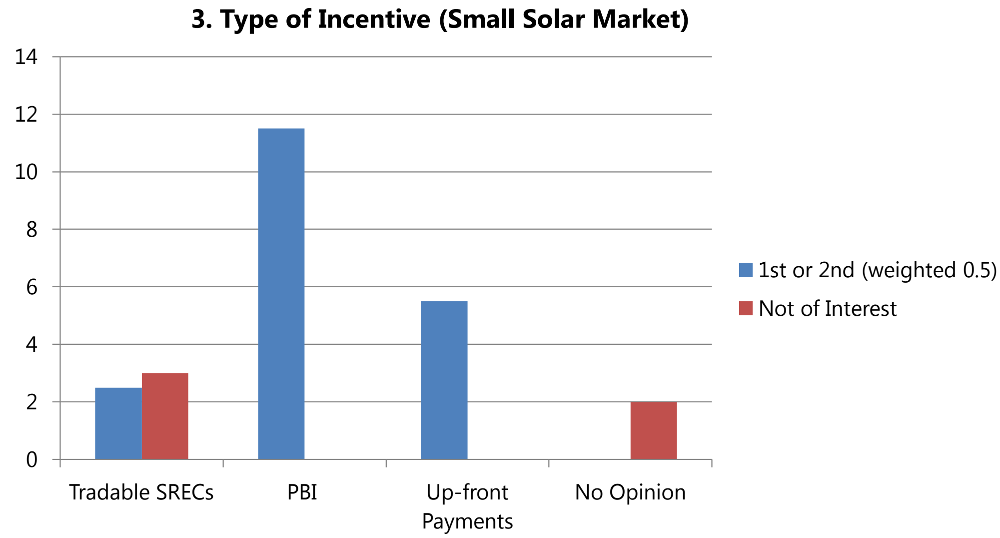
Question 3



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Question 3 Comments

- (Stillinger) Under Policy Alternative #3, Orderly Market Evolution, please examine an incentive for residential and small commercial solar projects that is structured as an up-front payment to the system owner that would be based on the estimated generation of the system over its initial years of operation (e.g. ten years).
- (Rabinowitz) National Grid favors PBI implemented through a tariff, and not through a long term contract. In addition, an incentive such as up-front payments should be borne by taxpayers, and ideally implemented through tax policy, rather than adding costs to electricity customers' bills.
- Under Policy Alternative #3, Orderly Market Evolution, please examine an incentive for residential and small commercial solar projects that is structured as an up-front payment to the system owner that would be based on the estimated generation of the system over its initial years of operation (e.g. ten years).
- (Besser, Rever, Aller,) Please examine an incentive for residential and small commercial solar projects that is structured as an up-front payment to the system owner that would be based on the estimated generation of the system over its initial years of operation (e.g. ten years).
- (Rio) This is complicated - technically I am preferring a performance based system. However, it is more of a hybrid. I believe small solar should be paid at power rates, not including T&D. This would eliminate the need for any real program changes and eliminate the need for minimum bills. However, to the extent there may be short term need for additional money, the ACP money can be used as kind of a floater, to give money when needed on short term (upfront), but be removed as needed.
- (Krathwohl) as applicable to this and following questions, i like a policy path yielding increased certainty in the PV market to allow participants to be able to plan and implement which in turn will faciltat achievement of the MW target and provide the benefits associated with increased solar development including more jobs. Ultimately this must be done at a cost that is not unreasonable, but more work must be done to see how the numbers fall out
- (Holland) Strongly consider a continued up-front rebate for small residential systems like the commonwealth solar program in addition to the PBI.

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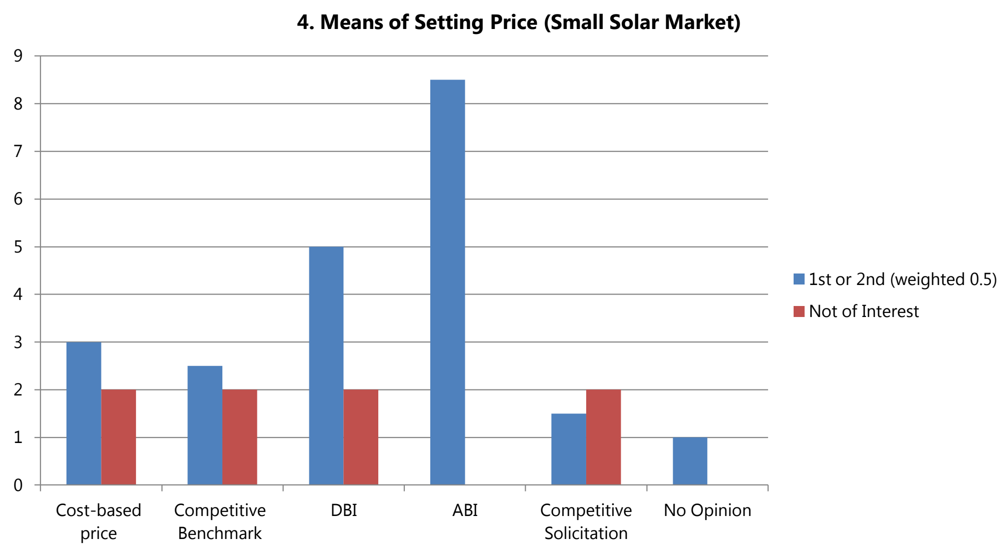
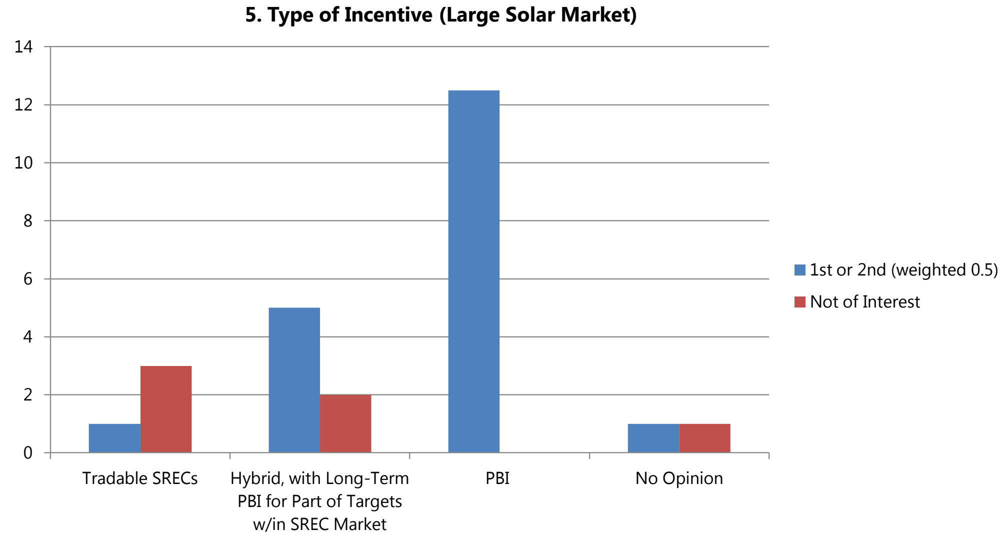
Question 4



Question 4 Comments

- (Rabinowitz) These options are all variations on a theme, & elements of one could be supported in another. In addition, any of the options above can and should be adjusted based on the amount of market response received, thus ABI does not seem like a separate price option. However, the goal should be to choose a means of lowering prices over time to limit the added costs to electricity customers' bills. Even the small solar market could become a competitive one, & a competitive market solicitation could inform the price that will be set by the government agency.
- (Brennan) Unclear about what the "distinct competitive event" would be -- would need additional information.
- (O'Connor) When modeling the declining block, please consider modeling the ability to respond to market conditions and the option of including market adders.
- (Rever) Also not of interest: competitive benchmark and competitive solicitation
- (Rio) same answer as Q3 - The price should not be "set" at all - the risk of solar should be on the owner - someone this program has turned into a risk-free proposition. The backstop could be the ACP, however, there is not legitimate reason why being a solar owner should be equivalent to printing money - the risk is on all the other ratepayers and the solar owner is not paying his or her share. the owner of the solar should receive power rates that are variable based on the need at the time - This could be done using a smart meter when they are available or could be done using some averages. it is completely unfair for a homeowner on basic service to be required to pay TVR (as some have proposed) while solar people get basic service rates at all times - using TVR for solar would force people to install the panels in a way they are maximizing benefit to the system not maximizing benefit to their pocket.
- (Krathwohl) Although i support some administrative process to determine a reasonable price there should be some constraints on that process - probably set in the legislation to ensure that the process no matter how well-intended -- is not susceptible to getting bogged down and as a result hinders the development of the solar market
- (Colton) Competitive bidding should be discouraged, particularly if the EDCs are going to be involved in the solicitation and selection process. The states uncoupling of distribution and generation shouldn't be compromised.
- (Aller) For small solar, competitive solicitation is not cost effective or feasible, and linking the incentive level to the values determined by competitive solicitation for large-scale solar has several risks: -There are several major cost drivers for small projects, especially residential, where costs would evolve differently than large projects: customer acquisition, permitting, inspection, and interconnect, and materials required by local electric code that drive large additions to the cost stack. -Even if an incentive multiplier is set accurately at the start, which is by no means easy, costs for residential/small and large projects do not evolve in a linked manner over time. -If the multiplier is set up to be adjusted regularly, that creates a policy and advocacy burden for participants in the small solar segment, which is of significant cost and risk as they are generally not set up to do this. For these reasons, please focus on using another incentive type for small solar, such as the adjusting block incentive discussed in other options (or SRECs), rather than linking the small solar incentive to competitive solicitation results for large solar.

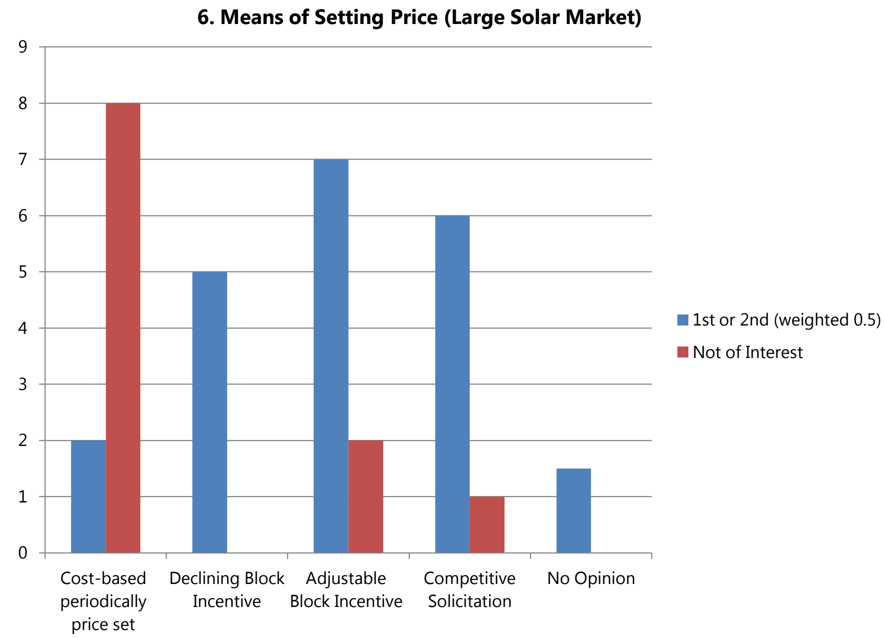
Question 5



Question 5 Comments

- (Rabinowitz) Tradable SRECs and a Hybrid approach are "Not of Interest." National Grid favors PBI, as long as it involves tariff-based payments, and not long-term contracts. Up-front Payments should be an option for this market as well. In addition, an incentive like up-front payments should be borne by taxpayers and implemented through tax policy, and not add costs to electricity customers' bills.
- (Brennan) Would want more information on the "hybrid" option.
- (Besser) Please examine an incentive for large projects that is structured as or includes an up-front payment to the system owner that would be based on the estimated generation of the system (PBI) over its initial years of operation (e.g. ten years).
- (Krathwohl) market certainty and financeability again are key components -- of course along with reaonable price.

Question 6



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Question 6 Comments

- (Rabinowitz) Any of the options above could be adjusted based on the amount of market response received, thus ABI does not seem like a separate price option.
- (Brennan) Would want additional information on the "adjustable block incentive" option.
- (O'Connor) When modeling the declining block, please consider modeling the ability to respond to market conditions and the option of including market adders.
- (Holland) Definition of large versus small projects an unresolved issue although SREC-II market sectors provide a good guideline. Competitive solicitation best suited for large projects with no onsite load (SREC-II market sector C)

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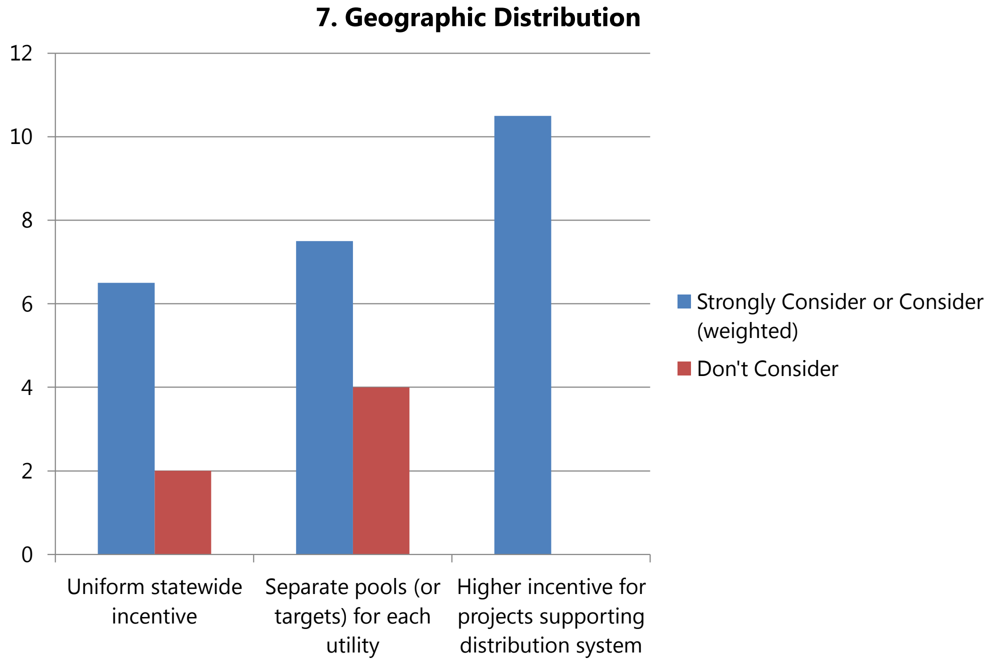
Question 7



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Question 7 Comments

- (Holland) Re: Higher incentive for projects supporting distribution system: Unresolved discussion topic: How do consumers ultimately share in any savings that may be realized if targeted solar projects successfully defer T&D investments? Assuming cost recovery of solar incentive payments remains similar to the existing model, ratepayers pay immediately for cost of solar incentive payments, but will only realizing savings from deferred T&D investments once the distribution company has a mandatory rate case. Should ratepayers share in any savings from deferred investments? Re: Separate pools for each utility - if this option is meant to address the disparate rate of solar development in different utility service territories, perhaps the issue is better addressed by standardizing the utility cost-recovery mechanism statewide and by inter-distribution company payments to address recovery under and over collections.
- (Rabinowitz) National Grid does not support a uniform statewide incentive unless it is to include a price cap and ensure a uniform selection process. Projects do not need further incentives, so a new incentive would require a different analysis of value – not a new layer. Essentially, National Grid supports fair compensation for distributed generation.
- (Serna) For any higher incentive for projects supporting the distribution system, it is important that those incentives can be quantified, tracked and proven to benefit the distribution system.
- (Brennan) The incentives need to be based on quantifiable benefits with some level of oversight.
- (Rio) This is the best thing to do. No objection to higher incentives when it can be proven that such installation helps the grid - However, this incentives should be for a short time as the benefits are likely to dissipate over time.
- (Aller) Differences in electric rates should be taken into account when setting incentives - less incentive is needed where electric rates and associated production credits are higher, for example. However, it is also important that separate pools be structured in a way that does not create complexity for developers, and that enables solar to be developed in a balanced way across the state, rather than being much more feasible in one area than another.
- (Krathwohl) though i recognize there are differences between utilities and operating realities must be considered, the simplicity of a uniform approach across the Commonwealth should be more beneficial and workable ultimately

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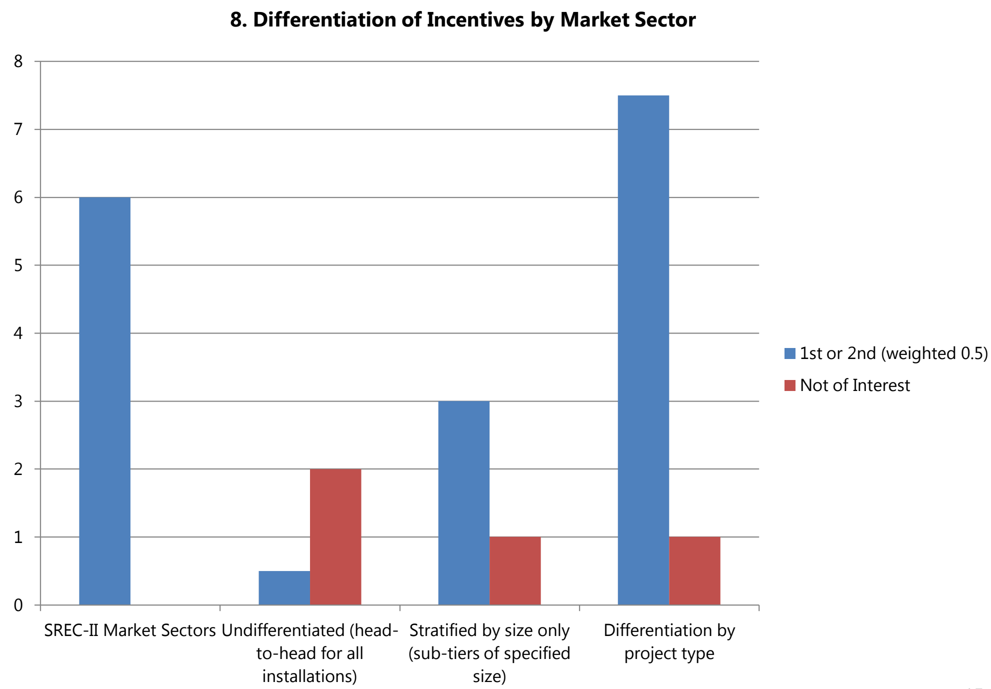
Question 8



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Question 8 Comments

- (Rever, Besser, Aller, Podgurski, Stillinger) Top Choice builds on the SREC-II Market Sector framework, and further segments the market based on (a) whether the owner benefits from depreciation tax deductions, and (b) the scale of the facility (e.g., stratification by size) and ensures low income category. This approach incorporates both social objectives and economic differences.
- (Rabinowitz) Because a large, stand-alone project costs less to develop, on a $ per watt basis, it needs less of an incentive than a "behind-the-meter" net metering project. Such "behind-the-meter" net metering projects, when sized correctly and when actually offsetting load, should be encouraged.
- (Brennan) Policies should reflect support for favored developments (i.e., brownfields, low-income, distribution system upgrade offsets)
- (Rio) I think the small solar leads more to TVR than the large solar, therefore the incentives should be different. The larger systems also will likely have more of an impact on the geographic issues. However, the costs of these programs need to be known. While this may be sold as a boon to low-income people, the laws of economics tell me that the other low-income people are paying the cost
- (Holland) Community Shared Solar/Low Income Solar within SREC-II market sector A may need to be closely examined to ensure sustainable solar growth
- (Serna) Any differentiation shouldn't be arbitrary. It should be structured to lead to a minimization of costs and maximization of benefits to customers.
- (Krathwohl) As recognized in the public comment, further support for low income and community shared solar is desirable (within reasonable cost parameters) and the differential support built into SREC-II (which presumably can be adjusted as market conditions suggest from time to time) is desirable

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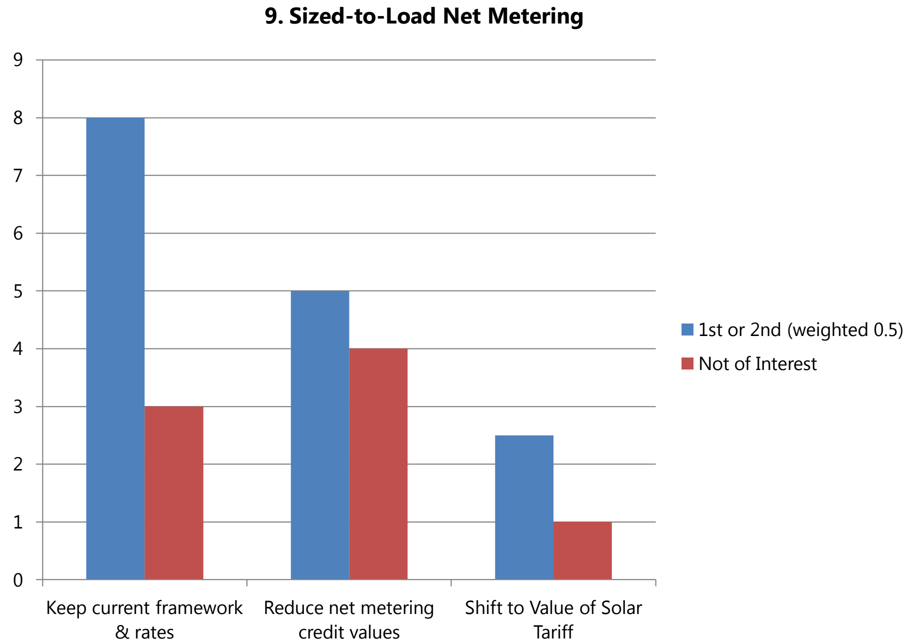
Question 9



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Question 9 Comments

- (Holland) Consider a net metering tariff that expires after a certain long-term period after solar installation followed by value of solar tariff after long-term period. Consider immediately shifting to value of solar tariff for very large industrial electric users (such as WMECo T-5 rate class) and prohibiting net metering or receipt of net metering credits by such users, limiting their facilities to value of solar tariff + additional incentive, but also exempting such customers from paying for any cost-recovery surcharge for net metering lost revenue recovery applicable to the other customer classes (except for grandfathered net metering cost recovery)
- (Rabinowitz) All of these options are "Not of Interest." We need a new framework, similar to energy efficiency incentives, that acknowledges that solar is an important policy goal and identifies the subsidy to the cost of solar that is needed to encourage the installation of solar. We hope for an evolution from net metering to a "value-of-services" two-way rate structure, as described in our earlier written comments to the consultants.
- (Rever) We have concerns over implementation details with regards to a Value of Solar Tariff.
- (Besser) Shift to VOS could be considered for the long term as more experience and information becomes available.
- (Serna) Choice of reduction of net metering credits as the first choice, assumes that the net metering credits will be set at the wholesale price of energy. Any value of solar tariff will need to be set in a regulatory proceeding and focus on quantifiable electric system benefits.
- (Brennan) This assumes that there is an alternate, transparent support framework in place as necessary.
- (Aller) Please consider any "value of solar" approach as calculation of the appropriate bill credit, rather than a tariff. While a value of solar credit approach has strengths, operationally it must be set up to limit the risk of policy-making market inefficiencies, such as utilities' ability to be reimbursed by ratepayers for their legal advocacy costs, and the associated imbalance in ability to fund balanced advocacy by other parties. There is also the necessity of clear data about the functioning and cost of the distribution grid to inform accurate analysis of the costs and benefits to the grid.
- (Krathwohl) Certainly pricing on the basis of economic benefits is sound, but i am concerned about what it would take to determine the value of solar. Net metering and virtual net metering especially from the public comments seem critical to continuing the solar market much less achieving the established goals and establishing a supportive framework thereafter.
- (Stillinger) Careful study needed for the second choice (VOST); not likely to be done in the task force's term. The implementation details are crucial here.
- (O'Connor) The reduction of net metering credit values can be size based and/or location based.

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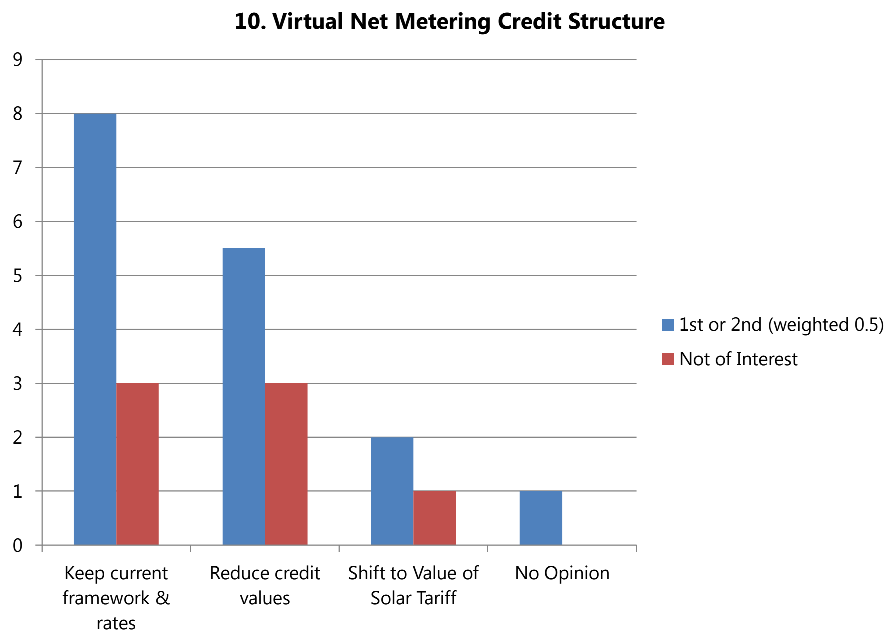
Question 10



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Question 10 Comments

- (Rabinowitz) All of these options are "Not of Interest." Virtual net metering projects should not be provided with net metering credits that are almost equal to retail rates because they increase customer costs and do not ensure that solar generation is co-located with an appropriate amount of load. Such projects should be provided only credits equal to the cost of supply. With the shift to a "value-of-services" model (see response to # 9, above), large virtual net metering units will appear as what they are, which is stand-alone generators, and would need to compete in general solicitations with like-sized units to garner any subsidy support, if available under a new program.
- (Brennan) This assumes that there is an alternate, transparent support framework in place as necessary. There may need to be additional consideration for unique, low-income customers who utilize virtual net metering.
- (O'Connor) For the reduction of credit values, the Department would be interested in modeling the current framework for low income customers and community shared solar and decrease credit values for all other customers.
- (Serna) Choice of reduction of net metering credits as the first choice, assumes that the net metering credits will be set at the wholesale price of energy. Any value of solar tariff will need to be set in a regulatory proceeding and focus on quantifiable electric system benefits. For virtual net metering, Eversource also strongly recommends ensuring any credit assignment be handled by another party and not the distribution company.
- (Rever) We have concerns over implementation details with regards to a Value of Solar Tariff.
- (Rio) VNM is where all the costs are as I understand it. Therefore, this is an area that needs to be tackled. A lot of these issues can be dealt with by doing a fair and honest accounting of what it actually costs to install these systems and who is making the money. it is extremely difficult to answer these questions without knowing the exact economics of these systems.However, based on what I know the these systems are being overused and overcompensated
- (Aller) Same points as question 9 about value of solar - while in an economic-theory view, a value of solar credit has many strengths, the ability to implement such an approach faces many real world challenges. As such, the current approach is a better and more cost effective way to move forward. For one, it avoids loading rate payers with the advocacy costs related to value of solar.

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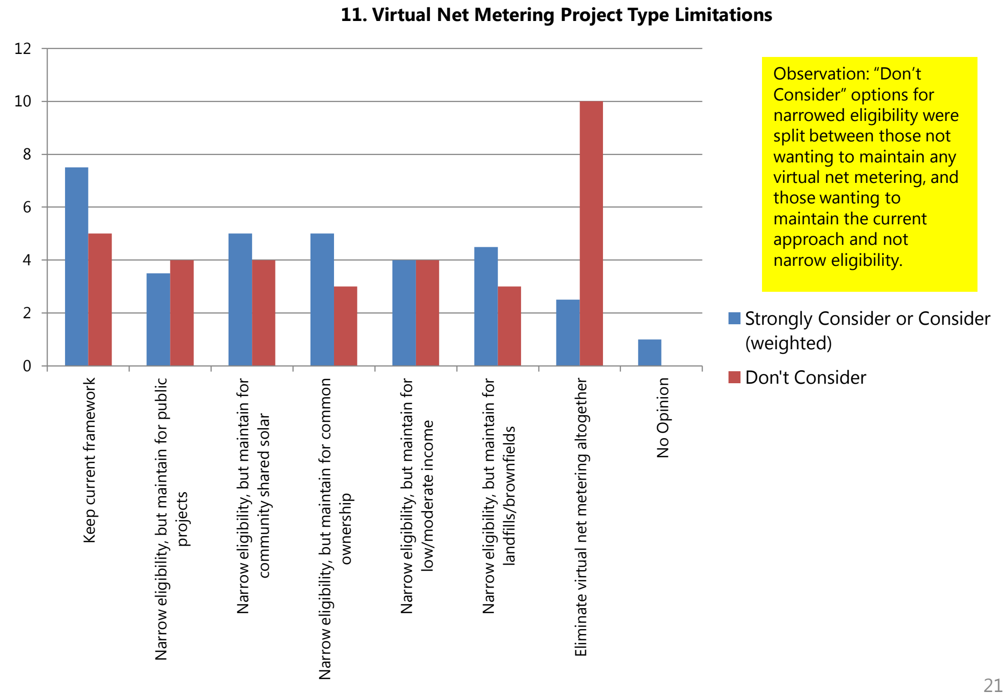
Question 11



Observation: "Don't Consider" options for narrowed eligibility were split between those not wanting to maintain any virtual net metering, and those wanting to maintain the current approach and not narrow eligibility.

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Question 11 Comments

- (Holland) Maintain VNM in current framework for residential properties where host customer account and customer account receiving credits share a common meter bank (or something along those lines) to ensure that condos, triple-deckers and other types of similar properties are not disadvantaged only because their property contains multiple electric meters/accounts. Consider maintaining VNM for excess credits associated with residential or small commercial on-site projects sized larger than load to maximize solar energy production on a particular rooftop, provided that most load (perhaps at least 67% over a year) is used on-site. Consider maintaining eligibility for common ownership/community shared solar projects, but modifications to credit structure may be appropriate. In order to send correct price signals and encourage the benefits associated with development on-site, a customer considering building a project off-site should receive a lower credit value to reflect some of the cost of delivering his energy across the network. Concerns for low-income customers may be legitimate, but may be better addressed and less discriminatory by broader reforms to rate structure that benefit all low-income or moderate income ratepayers.
- (Rabinowitz) Notwithstanding our selection above, NGrid supports providing low income customer with greater access to solar opportunities developed consistent with the framework that we envision. In addition, a "campus" approach to virtual net metering may be appropriate.
- (Serna) For virtual net metering, Eversource also strongly recommends ensuring any credit assignment be handled by another party and not the EDC.
- (Stillinger) VNM is especially important for low/moderate income, community shared solar, and small "common owner" situations (e.g. farms, churches, campuses, etc.). Consultants should analyze the impact of narrowing eligibility on solar development, benefits and costs to customers, and broad economic development, energy and environmental benefits to Commonwealth as a whole.
- (Besser) Consultants should analyze impact of narrowing eligibility on solar development, benefits and costs to customers, and broad economic development, energy and environmental benefits to Commonwealth as a whole.
- (Rever) Any review of narrowed eligibility should be justified and the impacts on the market sector of that narrowing be reviewed.
- (Rio) The problem with allowing VNM for some installation and not others is that we end up with one group of people (even within the same class) subsidizing others for absolutely no benefit to the system. At some point the best sites for VNM are going to be taken and the system will be left with a group of have- and have-nots. low income people who come off the system are not helping the low-income population as others are picking up the tab for all T&D and social programs. the basic model is unsustainable. therefore, solar installations should not be granted to anyone as a right - it should be done methodically as a benefit tot the system - and that means as a means of diversity as well as a means for reliability. VNM should be subject to a higher standard - it is expensive and if we can get a better bang for the buck somewhere else it should not be first come first serve or a matter of right. That is why I support brownfields - these are areas where the money spent on solar can be put to good use - that si a double benefit and those areas should be encouraged. .
- (Krathwohl) public comments strongly support the need for virtual net metering - especially for community shared solar and for low income customers. Any policy path followed must consider cost impacts on customers but also the benefits -- short and long term -- from support of solar installations.
- (Colton) Virtual Net Metering is beneficial to municipalities and low income communities. It should be expanded to capture rental housing, private non-profit institutions such as hospitals and universities.

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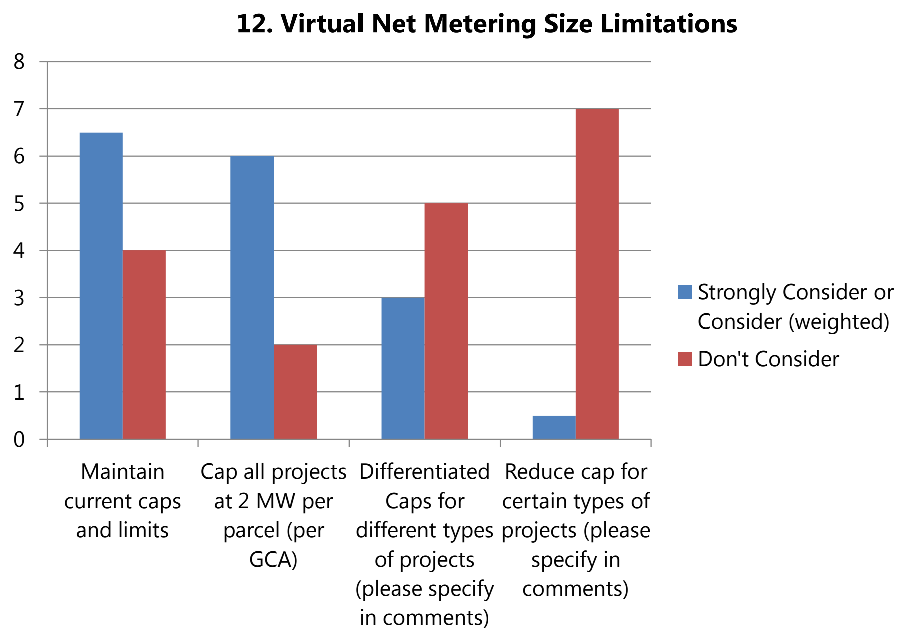
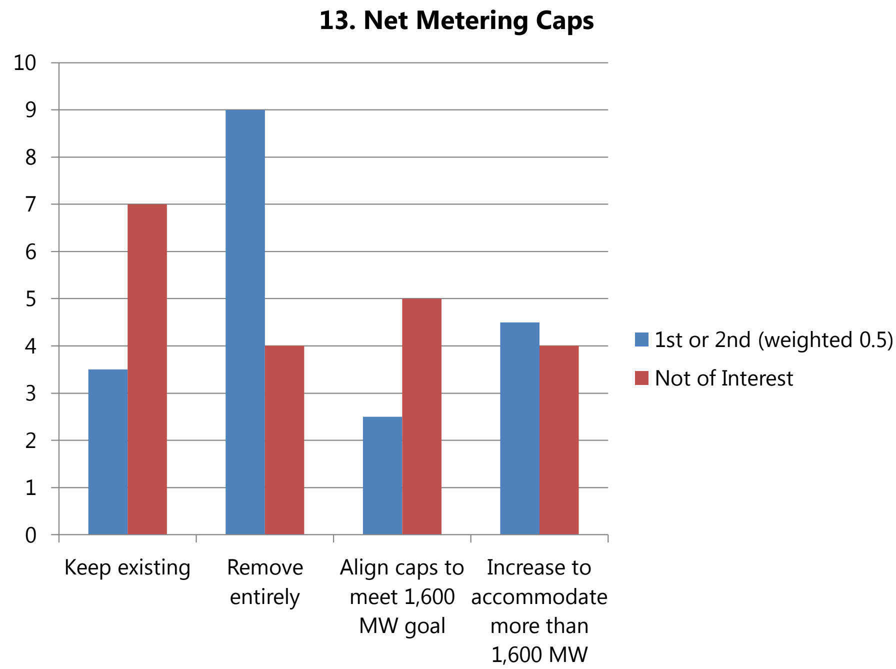
Question 12



Question 12 Comments

- (Podgurski) Consider capping at 2 MW or differentiated caps, but only for studying
- (Brennan) This would depend on the level of payment, and whether virtual net metering is restricted to certain types of projects.
- (O'Connor) Possible size limitations for virtual net metering was not previously discussed in the Consultant presentations. Absent a discussion of the various options presented here and their possible impact on modeling, the Department is not able to indicate any preference
- (Besser) Consultants should analyze impact of 2 MW size cap and differentiated caps on solar development, benefits and costs to customers, and broad economic development, energy and environmental benefits to Commonwealth as a whole.
- (Serna) Project size limitations should consider ISO-NE wholesale market rules and aggregate thresholds for settlement only generating units.
- (Rio) I see no reason to limit projects to some arbitrary size PROVIDED they meet criteria of benefitting the system and the cost has been rationalized. I don't really understand the reason for the caps in the first place, other than perhaps to limit costs. Get the costs and process under control and we can eliminate caps.
- differentiated caps ala SREC 2 might be a good approach
- (Harak) Different (more generous than for other sectors) caps for community shared solar, projects serving low/mod income, muni sector.
- (Krathwohl) differentiated caps ala SREC 2 might be a good approach

Question 13



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Question 13 Comments

- (Rabinowitz) Except for "Keep Existing" net metering caps, the other choices are "Not of Interest." Notwithstanding our response above, any further increases to the net metering caps should be accompanied by changes to credit values for virtual net metering projects. Please see the responses to # 10, #11, and #12, above
- (Brennan) With adequate rate design (via DPU rate case) and adjustment for the net metering payment in place, the cap could be removed entirely.
- (Fisher) en. Downing asks that I answer no opinion to all with the exception that he would like to make sure that aligning the cap to meet the 1600MW goal remains in the discussion.
- (Besser) If not removing caps entirely, should look at increasing to accommodate more than 1600 MW to ensure smooth transition (i.e., don't create a cliff or "gold rush").
- (Serna) Eversource will continue to recommend to keep the existing caps as long as the net and virtual metering model leads to rate inequity and above market costs.
- (Rio) Same answer as above - the caps are arbitrary - we keep fighting over them because of cost issues. Clearly they are too rich. If the cost and net metering is done right, the market can decide the right trajectory - currently the system is being manipulated and therefore we need to maintain caps
- (Krathwohl) removing caps is certainly an idea that found significant support in the public hearings. If the consultant ran some models on this path and the economic burden was not excessive, this might be a way to go.
- (Holland) If caps needed, consider a cap based on non-participating customer rate impact instead of existing even-more arbitrary cap structure.
- (Aller) Keeping existing caps would reduce the amount of federal money coming to MA, by reducing the speed of solar development before the end of 2016.

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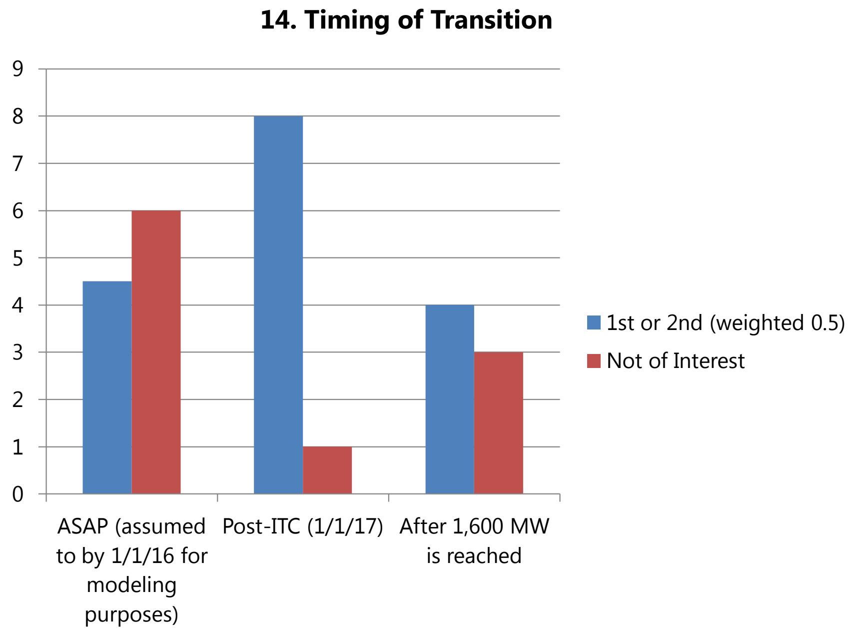
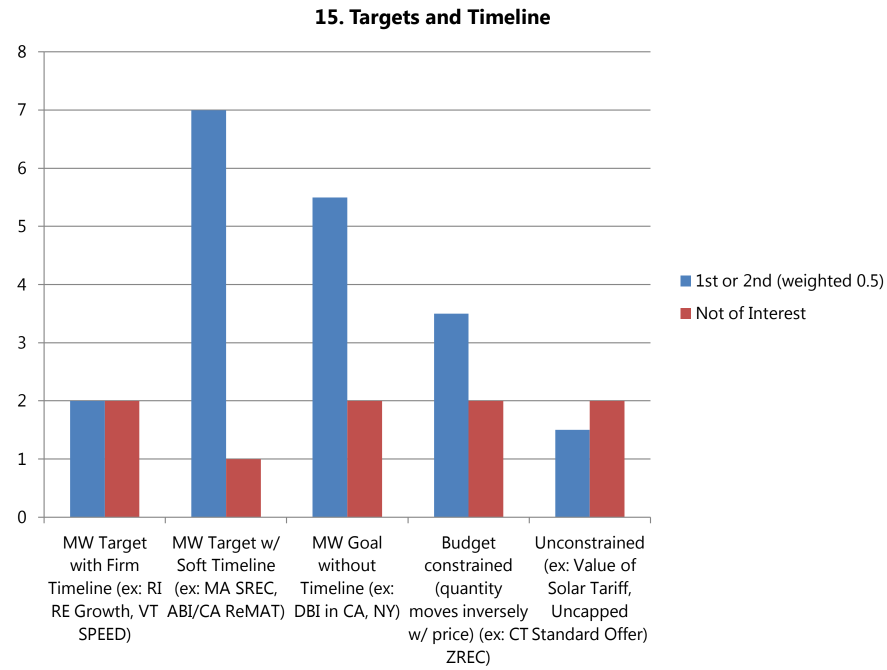
Question 14



Question 14 Comments

- (Rabinowitz) Except for "As early as possible (01/01/2016)," the other choices are "Not of Interest." Immediate action is necessary in order to contain the costs of the SREC and net metering programs for electricity customers.
- (Brennan) Transition should consider existing commitments/projects - but this requires additional discussion and flexibly on how that is achieved.
- (O'Connor) The Department would prefer not to tie the transition to any potential incentive changes at the federal level.
- (Krathwohl) a more sustainable, supportive yet balanced structure should be implemented as soon as possible in order to take advantage of the Federal ITC
- (Aller) A transition before 2017 would have massive costs to the state in both jobs and dollars - solar businesses would cut back due to uncertainty, and business looking to use solar to gain predictability into their energy costs, as we heard at the task force meeting 2/25, would lose that ability. Furthermore, this would reduce the federal money coming to MA by delaying solar development before the federal ITC expires for residential and steps down 66% for commercial.

Question 15



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Question 15 Comments

- (Rabinowitz) Except for "Budget constrained" and "MW Target with Firm Timeline," the other choices are "Not of Interest." The policy framework should require the solar development community to work within a defined budget and increase the cost efficiencies. Experience has shown that the incentives are much higher than necessary to encourage solar development, and especially large solar projects.
- (Brennan) Targets and timelines need to be focused on getting to a point where you are supporting the market to self-stabilization.
- (Rio) If the program is aligned right, I believe we can get more and better sytsems installed.
- (Holland) Applicable to incentive payment, not net metering.
- (Aller) An adjustable block incentive where each block is a known dollar amount, and what varies based on market signals is the per-unit incentive should be considered.

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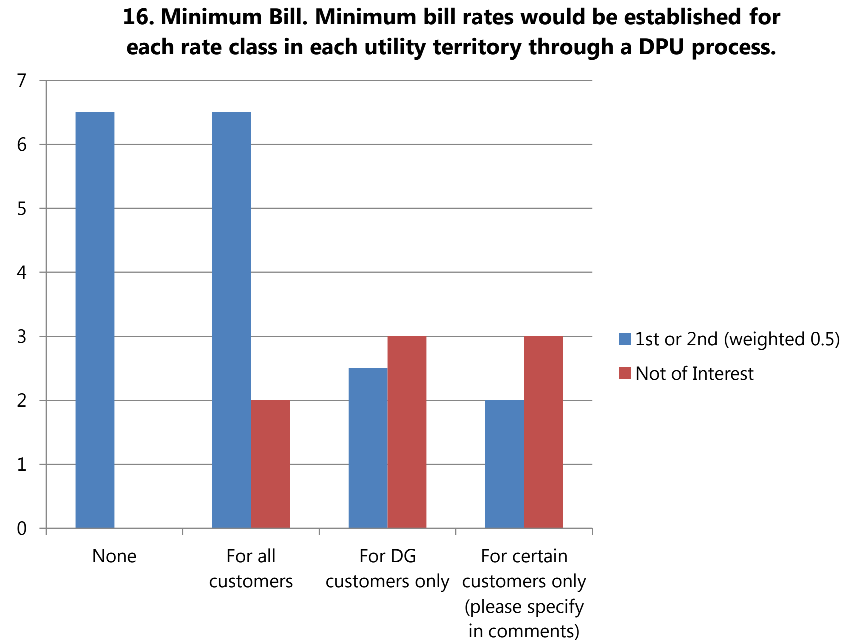
Question 16



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Question 16 Comments

- (Rabinowitz) National Grid would support a minimum bill for distributed generation customers only if it were designed correctly. National Grid seeks an opportunity to explore and elaborate on what the correct design would involve.
- (Stillinger) It comes as no surprise to anyone that this is a politically explosive issue. Any min. bill must be capped for residential and other small-scale users. This is one way to ensure that all customers pay fairly and equitably for their use of the "grid".
- (Brennan) This is an important issue, but the question as framed is difficult to answer. The parameters of the min. bill "credit" need to fleshed out in a DPU process. The concept of a minimum bill applying across the board could be considered, but then different classes/customers who use the grid differently should have minimum bills that reflect the costs associated with their classes. Any minimum bill discussion must include an evaluation of impacts on low income & low usage customers before implementation.
- (O'Connor) The Department understands that consideration of a minimum bill is part of the mandate of this task force. However, the Department views a minimum bill and the policy paths as separate issues and therefore recommends that any policy option modeled consider two scenarios: one in which a minimum bill is applied, and one in which it is not
- (Besser) If DPU finds that a minimum bill is necessary, it should be nondiscriminatory across all customers (adjusted by rate class or size with provisions to protect low income customers taken as second step if needed).
- (Serna) Eversource supports a greater amount of cost recovery through fixed charges as it more properly assigns costs to customers thereby reducing both intra- and inter-class subsidization of costs. The transmission and distribution system is largely a fixed cost in which volumetric usage does not have a direct bearing on the costs incurred by any particular customer. Greater fixed cost recovery should be considered as part of an overall rate design approach to replace net metering. Rate design should be addressed in a fully adjudicated rate proceeding before the DPU. Such investigation should explore the proper rate design needed to ensure that the Department's rate-making goals continue to be met in light of the rapid growth of distributed generation.
- (Rever) also not of interest: for certain customers only
- (Rio) If the program is aligned right, with customers only receiving power rebates, minimum bill goes away since the customer is still contributing T&D and social programs. if the system stays as is then minimum bills based on a true analysis of the cost must be implemented for DG customers. the key is to do a true analysis to see what it is.
- (Krathwohl) This seems to be quick a tricky issue. Certainly the general ratemaking goal of rates reflecting costs imposed on the system is good and if applied correctly that is what a minimum bill would do. One concern is, as noted above, the process of setting the minimum bill getting in the way of the solar market development, which is a condition to be avoided. Another concern made clear through the public comments concerns seasonal customers and small farms and other businesses for whom a minimum bill could distort their economics. Those concerns need to be considered though it might require a more refined costing analysis than has often occurred in utility ratemaking over the years.
- (Colton) If one applies the min. bill concept to the extreme, i.e., ratepayers who reduce use to zero would pay a min. bill...in my view this makes the min. bill a tax, rather than a fee or user charge. Taxes should not be levied by anyone other than the Legislature. ANY min. bill is regressive & would adversely affect low income users & municipalities. It is not a door that I would willingly open.
- (Holland) For solar customers or those receiving virtual net metering credits. Grandfather existing net metering customers. For residential customers, consider limiting to existing customer charge and furthermore delaying any minimum bill until an agreed-upon non-participant net metering rate impact.

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Policy Paths Chosen for Modeling

Name	A: EDC-centric: Competitive Solicitations	B-1: 'Open'	Notes
3. Solar Small: Type	✓PBI	✓EPBI	[1]
4. Solar Small: Setting	✓DBI w/ Safety Valve	✓DBI w/ Safety Valve	[2]
5. Solar Large: Type	✓PBI	✓PBI	
6. Solar Large: Setting	✓Competitive Solicitation	✓DBI w/ Safety Valve	
7. Geog. Distribution	✓solar (not NM) incentives vary by EDC but MW are a statewide block with ex-post $ reconciliation btw EDCs to equalize cost impact		[3][4]
8. Differentiation by Market Sector	✓Based on SREC-II		[5]
9. Sized-to-Load Net Metering rate applicable to billing period roll-forward	✓G Rate	✓Current components of retail rate	
10. VNM Credit Structure (applicable to net excess after roll-forward)	✓W/S rate	✓Current framework &rates	
11. VNM Proj. Type Limitations		n/a	
12. VNM size limitations		✓Keep current	
13. NM Caps	(i) No Caps; (ii) Current Caps	(i) No Caps; (ii) Align to match reaching 1,600 MW target, not on a % of peak load basis	
14. Timing of Solar Policy Transition	1/1/17	Once 1600 MW reached	[6]
15. Targets and Timeline	✓Set targets ramping up to 2500 by 2025 (proxy for possible 'budget-limited' approach)	✓2500 MW with no hard timeline; calibrate modeled incentives to match 2500 by 2025 as best possible	
16. Min Bill	✓ n/a		[7]
Disposition of RECs	✓ For all: assume RECs minted as Class I and resold into market (consistent with RI, CT approach)		

Notes for Prior Slide

1. EPBI is an upfront incentive (rebate) that is based on *expected* production over a time period (with claw-back if underperforms), similar to used in NY and as requested by several TF members.
2. Modeling of DBI and ABI are *similar* if assumed costs drop over time. ABI model in practice is more complex to model. Define as "DBI with safety valve" that has option for administrative change, and start after 1/1/17 post-ITC (also after energy prices expected to start to abate), allowing a modeling as declining incentive; allows simplification of analysis.
3. "Higher incentive for supporting projects supporting Distribution system" had near unanimous support; but also EDCs point out that there is not currently system-wide information on which to base modeling. Apparent consensus among TF, where all understand this could improve cost/benefit, and is therefore a potential TF recommendation; we propose not to model.
4. Choice among separate pools by utility or uniform statewide incentive need to be meaningfully linked to Net Metering modeling choice. One argument for separate pools would be driven substantially by rate differences, which would disappear if NM discontinued.
5. May be very difficult to model many of variation that have been requested or suggested ➔ need choice to be simple enough to model; does not preclude TF deciding to recommend more nuanced changes.
6. *Modeled* transitions must be chosen to simplify modeling while revealing maximum learning; ASAP is, realistically, within months of 1/1/17. Modeling choice does not preclude recommendation for earlier transition.
7. All seem to agree that min. bill design and applicability is best left for DPU, and effort to design and analyze is extensive. Furthermore, impact depends heavily on the details. If designed so that incentive is increased to offset min. bill, then impact is distributional, and in aggregate is none. If incentive is not increased, then all agree that economics would be negatively impacted, reducing adoption, *all else equal*. Can we separate this issue from all models in Task 3, and illustrate on a more limited basis under Task 5?

La Capra

(2)

Appendix D: Utility Data Request and Responses

[redacted]

From: OConnor, Angie (DPU) [angie.oconnor@state.ma.us]
Sent: Thursday, April 02, 2015 12:34 PM
Subject: Information Request

Dear Task Force Members,

I apologize for the delay, The information request that was put forth to the utilities at last week's Task Force Meeting is reflected below:

I would like the utilities to provide a projection of the total cost for solar generation support programs starting in **2014 and extending to 2020** showing the cost shift from net metering credits related to distribution, commodity and other rate components, and the total actual and projected SREC costs in each year. Provide these costs - both as a total dollar amount, on an annual basis and over the whole time period per utility, and also the annual and total cost for each type of customer for each utility (e.g., residential, low income, commercial and industrial, etc).

Please coordinate with each other to make sure you are using consistent assumptions, or if they are different, please explain why they need to be. In addition, please state all assumptions and provide calculations in working Excel spreadsheet format. Thank you for providing this information as soon as possible.

Angela M. O'Connor, Chairman
Massachusetts Department of Public Utilities
One South Station
Boston, MA 02110
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EVERSOURCE ENERGY

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April 14, 2015

Net Metering and Solar Task Force
Attention: Co Chairs Angela O'Connor and Daniel Burgess
RE: Response for Information Request

Dear Ms. O'Connor and Mr. Burgess:

I am attaching Eversource's response to the information request received by Eversource on April 2nd, 2015.

The attached analysis shows the effect and magnitude of the costs being shifted from customers that net meter to customer that do not. It is an analysis of cost and rate impacts, and does not represent an analysis of the costs associated with integrating these resources into the system.

The summary of the costs by year between 2014 and 2020 is presented in the table below.

Total Cost to Support Solar Generation ($M)	2014	2015	2016	2017	2018	2019	2020
Net Metering	20.8	41.9	46.8	62.4	75.3	81.7	87.8
SREC	77.9	261.7	286.7	252.0	246.8	249.7	249.7
Total	98.7	303.7	333.4	314.5	322.1	331.4	337.6

For Eversource the costs will increase from close to $100 million in 2014 to $338 million by 2020. Total cost to customers from 2014 to 2020 will be $2.0 billion.

Both the net metering and the SREC credits will experience significant increases. Net metering will increase from $21 million in 2014 to $88 million in 2020 and SREC incentives will increase from $78 million in 2014 to $250 million in 2020.

In addition it is worth highlighting that Massachusetts customers will pay roughly 60 c/kWh for solar electricity in 2015. Meanwhile, wind generation has been purchased for around 8 c/kWh under long-term contracts and, nearby, Connecticut is supporting new solar projects for less than 25 c/kWh. Massachusetts is paying more than it needs to for new solar.

Please let us know if there are any questions on the analysis as we stand ready to provide any additional information that might be required.

Kind regards,

Camilo Serna

Eversource Solar RPS & Net Metering Cost Summary

	2014	2015	2016	2017	2018	2019	2020
Distribution Load (MWh)							
Gross Load (MWh)	25,741,623	26,037,001	26,001,219	25,854,714	25,574,650	25,355,855	25,149,735
Less: Net Metered Solar Generation	(237,299)	(391,393)	(502,159)	(630,344)	(714,656)	(770,829)	(808,297)
Net Load (MWh)	25,504,324	25,645,608	25,499,060	25,224,370	24,859,994	24,585,026	24,341,438
Solar % of Load	*0.9%*	*1.5%*	*1.9%*	*2.4%*	*2.8%*	*3.0%*	*3.2%*
Total Cost to Support Solar Generation ($M)							
Net Metering	20.8	41.9	46.8	62.4	75.3	81.7	87.8
RPS	77.9	261.7	286.7	252.0	246.8	249.7	249.7
Total	98.7	303.7	333.4	314.5	322.1	331.4	337.6
Total Solar Cost by Customer Class ($M)							
Residential	32.3	96.8	106.3	102.5	106.4	110.0	112.5
Low Income	3.0	9.0	9.9	9.6	9.9	10.3	10.5
Commercial & Industrial	63.4	197.9	217.2	202.4	205.8	211.2	214.5
Total	98.7	303.7	333.4	314.5	322.1	331.4	337.6
Rate Impact by Customer Class (c/kWh)							
Residential	0.4	1.3	1.4	1.4	1.4	1.5	1.5
Low Income	0.4	1.3	1.4	1.4	1.4	1.5	1.6
Commercial & Industrial	0.4	1.2	1.3	1.2	1.2	1.3	1.3

Eversource Net Metering Analysis

	2014	2015	2016	2017	2018	2019	2020
Distribution Load (MWh)							
Gross Load (MWh)	25,741,623	26,037,001	26,001,219	25,854,714	25,574,650	25,355,855	25,149,735
Less: Solar Generation	(237,299)	(391,393)	(502,159)	(630,344)	(714,656)	(770,829)	(808,297)
Net Load (MWh)	25,504,324	25,645,608	25,499,060	25,224,370	24,859,994	24,585,026	24,341,438
Solar % of Load	*0.9%*	*1.5%*	*1.9%*	*2.4%*	*2.8%*	*3.0%*	*3.2%*
Average Net Metering Rate Components (c/kWh)							
Energy (Basic Service)	9.4	12.2	9.6	10.7	12.0	12.3	13.1
Transmission	2.4	2.1	2.1	2.1	2.1	2.1	2.0
Transition	0.4	0.1	0.1	0.1	0.1	0.1	0.1
Distribution	5.3	5.3	5.4	5.4	5.4	5.4	5.4
DSM	0.25	0.25	0.25	0.25	0.25	0.25	0.25
Generation by Segment (MWh)							
Displaced Load	89,844	146,286	193,232	238,474	272,620	298,317	321,789
Excess Generation							
Class I, II & III (Public)	131,623	213,615	261,853	322,150	352,623	365,575	364,936
Class III (Private)	15,832	31,492	47,073	69,720	89,412	106,937	121,573
Total Net Metering Credit by Segment ($M)							
Displaced T&D Credit	7.5	11.4	15.1	18.6	21.3	23.4	25.3
Excess Generation Credit							
Class I, II & III (Public)	23.0	42.1	45.0	58.8	69.0	72.6	75.5
Class III (Private)	1.9	4.5	5.6	9.0	12.7	15.5	18.6
Total Net Metering Credits ($M)	**32.4**	**58.0**	**65.6**	**86.5**	**103.1**	**111.4**	**119.4**
Settlement Value (c/kWh)							
System Load Reduction	9.4	12.2	9.6	10.7	12.0	12.3	13.1
Wholesale Settlement	7.6	5.6	5.5	5.4	5.4	5.3	5.4
Excess Generation by Use (MWh)							
System Load Reduction	21,646	35,472	44,927	54,423	61,359	66,412	70,706
Wholesale Settlement	125,809	209,636	263,999	337,448	380,676	406,099	415,802
Total Settlement Value ($M)	**(11.6)**	**(16.1)**	**(18.9)**	**(24.1)**	**(27.8)**	**(29.7)**	**(31.6)**
Total Net Metering Cost Shift ($M)	**20.8**	**41.9**	**46.8**	**62.4**	**75.3**	**81.7**	**87.8**
Net Metering Cost by Customer Class							
Total ($M)							
Residential	8.8	17.7	19.8	26.4	31.8	34.5	37.1
Low Income	0.8	1.7	1.9	2.5	3.0	3.3	3.5
Commercial & Industrial	11.2	22.5	25.1	33.5	40.4	43.9	47.2
Rate Impact (c/kWh)							
Residential	0.11	0.23	0.26	0.35	0.43	0.47	0.51
Low Income	0.12	0.24	0.26	0.36	0.44	0.48	0.52
Commercial & Industrial	0.07	0.13	0.15	0.20	0.24	0.27	0.29

Customer Class Allocation Factors

Revenue	
Residential	42%
Low Income	4%
Commercial & Industrial	54%
Sales	
Residential	30%
Low Income	3%
Commercial & Industrial	67%

Eversource Solar RPS Analysis

	2014	2015	2016	2017	2018	2019	2020
Compliance Obligation							
SREC I	0.9481%	2.1442%	1.90%	1.58%	1.48%	1.47%	1.47%
SREC II	0.0843%	0.3288%	1.00%	1.34%	1.55%	1.77%	1.96%
Total	1.032%	2.473%	2.90%	2.91%	3.02%	3.24%	3.42%
SREC Price ($/MWh)							
SREC I	289	428	446	371	356	345	335
SREC II	371	310	275	309	303	288	273
Total Solar RPS Cost ($M) [1]							
SREC I	69.9	235.6	216.4	147.9	130.4	124.6	119.6
SREC II	8.0	26.1	70.3	104.2	116.4	125.1	130.1
Total	**77.9**	**261.7**	**286.7**	**252.0**	**246.8**	**249.7**	**249.7**
Solar RPS Rate Impact (c/kWh)							
SREC I	0.28	0.92	0.85	0.59	0.53	0.51	0.49
SREC II	0.03	0.10	0.28	0.42	0.47	0.51	0.54
Total	0.31	1.03	1.13	1.01	1.00	1.02	1.03
Solar RPS Costs by Customer Class ($M)							
Residential	23.5	79.0	86.6	76.1	74.5	75.4	75.4
Low Income	2.2	7.3	8.0	7.1	6.9	7.0	7.0
Commercial & Industrial	52.2	175.4	192.1	168.9	165.4	167.3	167.3
Total	77.9	261.7	286.7	252.0	246.8	249.7	249.7

[1] Excludes Solar RPS included in Net Metering costs

Line Loss Factor 0.66%

Eversource Net Metering Capacity & Generation

	2014	2015	2016	2017	2018	2019	2020
Net Metered Capacity (Est. Nameplate MW)							
Non-Solar	34.1	34.1	34.1	34.1	34.1	34.1	34.1
Solar (Capped)	177.8	322.6	388.2	470.6	525.2	562.9	566.5
Solar (Exempt)	46.1	72.3	98.5	111.6	129.1	146.6	164.1
Total	258.0	429.1	520.8	616.4	688.4	743.6	764.7
Generation by Settlement (MWh)							
Consumed Onsite	89,844	146,286	193,232	238,474	272,620	298,317	321,789
System Load Reduction	21,646	35,472	44,927	54,423	61,359	66,412	70,706
Wholesale Settlement	125,809	209,636	263,999	337,448	380,676	406,099	415,802
Total [1]	237,299	391,393	502,159	630,344	714,656	770,829	808,297
Excess Generation by Class (MWh)							
Class I	11,645	18,768	25,455	31,198	35,937	39,716	43,557
Class II	51,762	83,838	105,062	133,741	150,610	160,302	163,309
Class III (Public)	68,216	111,009	131,336	157,211	166,076	165,557	158,070
Class III (Private)	15,832	31,492	47,073	69,720	89,412	106,937	121,573
Total	147,455	245,107	308,927	391,870	442,035	472,511	486,508
% of Load	0.9%	1.5%	1.9%	2.4%	2.8%	3.0%	3.2%

[1] Excludes parasitic station load

Amy G. Rabinowitz
Vice President & Deputy General Counsel

nationalgrid

April 13, 2015

Net Metering and Solar Task Force
Attention: Co-Chairs Angela O'Connor and Daniel Burgess

Re: Net Metering Task Force; Response to Information Request

Dear Ms. O'Connor and Mr. Burgess:

I am attaching National Grid's response to the information request you posed at the March 26, 2015 task force meeting.

This analysis shows the effect and magnitude of shifting costs from customers who are net metering to customers who are not so that National Grid recovers its set revenue allowed by the Department of Public Utilities, and the costs of the Solar Carve-Out program within the Renewable Portfolio Standard (RPS), as regulated by the Department of Energy Resources. It is an analysis of rate impacts, and shifting recovery from one group of customers to another. It is not an analysis of the costs incurred by National Grid to interconnect or support solar distributed generation or any benefits provided by distributed generation. These cost shifts occur regardless of any benefit that solar could provide.

Massachusetts incentivizes solar through a combination of net metering and solar renewable energy credits, or SRECs. The net metering credit includes delivery and retail commodity components. By 2017, we project that the cost shift from net metering customers to ones who are not net metering will exceed $100 million per year. In addition, SREC costs added to retail commodity rates are increasing substantially, nearly quadrupling from 2014 to 2015, and then will remain above $200 million per year through 2020. These costs are primarily borne by customers who do not net meter. Customers who do net meter also benefit from the increase in the commodity rate related to SRECs, in addition to the actual SREC. In total, we estimate that our non-net metering customers will pay nearly $2 billion from 2014 to 2020 in support of the Commonwealth's solar programs, adding materially to customer rates and total bills. A summary table of the costs by year is shown below.

Costs in millions	2014	2015	2016	2017	2018	2019	2020
Net Metering	$34.6	$71.1	$84.5	$102.1	$108.5	$110.9	$112.1
SREC I	$52.1	$207.6	$174.8	$121.6	$111.0	$107.0	$103.5
SREC II	$6.5	$20.8	$58.9	$87.1	$98.7	$107.2	$112.5
Total	$93.3	$299.5	$318.2	$310.7	$318.2	$325.1	$328.0

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Importantly, generation that is exported for virtual net metering (VNM) creates a higher total cost that is shifted to other customers than generation used on-site. The exported energy from VNM systems is provided a credit for commodity at the full basic service rate, along with other rates appropriate to each system's rate class and net metering class, which is then transferred to a customer at a different location. The customer using the credit in another location, however, is still being provided energy by the utility or another energy supplier. For VNM participants receiving basic service, for example, the Company must pay its suppliers to serve those customers, but is crediting those customers for the energy generated at another location. The exported energy from systems greater than 60 kW is settled with ISO-NE at the wholesale energy rate (see Line 20 of "Net Metering Costs"), the proceeds of which are used to reduce the total cost of net metering. However, the difference between the wholesale rate and the basic service rate, which includes value for capacity, RPS compliance and ancillary services, is then collected from all customers as part of the basic service cost reconciliation mechanism. This is what accounts for a large share of the higher cost associated with virtual net metering generation.

Thank you for your time and attention to this matter.

Very truly yours,

Amy G Rabinowitz

Amy G. Rabinowitz

Information Request:

Provide a projection of the total cost for solar generation support programs starting in **2014 and extending to 2020** showing the cost shift from net metering credits related to distribution, commodity and other rate components, and the total actual and projected SREC costs in each year. Provide these costs - both as a total dollar amount, on an annual basis and over the whole time period per utility, and also the annual and total cost for each type of customer for each utility (e.g., residential, low income, commercial and industrial, etc.).

Please coordinate with each other to make sure you are using consistent assumptions, or if they are different, please explain why they need to be. In addition, please state all assumptions and provide calculations in working Excel spreadsheet format. Thank you for providing this information as soon as possible.

National Grid Response:

Please see the attached Excel spreadsheet.

These projections assume that distributed generation systems using the net metering caps of 5% public and 4% private, which are today fully subscribed in National Grid service territory, are fully interconnected by mid-2016, and that the caps are not raised beyond those levels. Additional net metered systems that are not subject to the caps will continue to be added to National Grid's system in subsequent years (see tab "Net Metering Costs", Line 2). National Grid collaborated with Eversource to use a common projection for the addition of statewide solar installed under the Solar Carve-Out programs and the compliance obligations for these programs (shown on "SREC Costs", Lines 1-3 and 6-7). National Grid and Eversource also used similar estimates of SREC values, using market values for 2014, 2015 and 2016, and then an average of the Alternative Compliance Payment and the Clearinghouse Auction Floor Price for 2017-2020 (Lines 4-5).

For net metering costs, National Grid assessed the amount of net metered generation connected to its distribution system in each month of 2014, and the amount of exported net metering generation from these systems as reported by the billing system, such as from virtual net metering systems, which have very little on site load. The difference is the estimate of net metered system generation that is used on-site (i.e., coincident with a customer's load), and this percentage is expected to decrease in the near term due to the increase in virtual net metering systems in the Company's interconnection and net metering queues. Amounts used on-site are then multiplied by the distribution rate to estimate the displaced distribution revenues, shown on

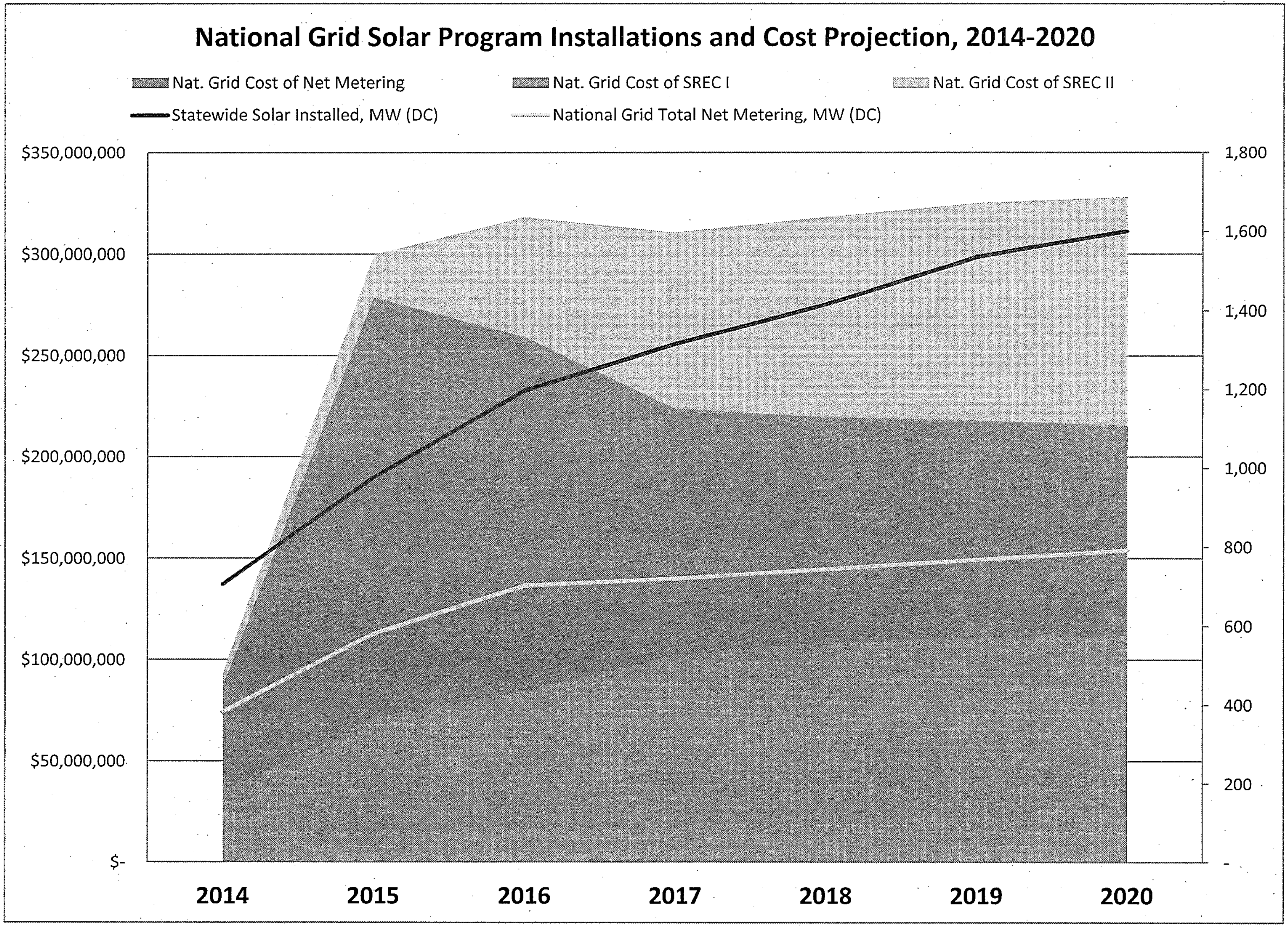
"Net Metering Costs," Line 12. Amounts that are exported are multiplied by each rate component, each shown individually on "Net Metering Costs," Lines 13-16.

Solar Carve-Out costs reflect costs for all distribution customers as reflected in commodity rates, as market costs for SRECs are similar for all load serving entities. The utilities used the same estimated compliance obligations and pace of installation of qualifying SREC II systems, set to allow the 1600 MW goal to be met in 2020, similar to the pace of installation proposed by the Task Force's consultants on March 26, 2014. Based on this projection, the Solar Carve-Out will add approximately one cent per kilowatt-hour to commodity rates each year from 2015 to 2020, with costs by customer class shown on "SREC Costs," Lines 20-22.

National Grid Summary of Installations, Net Metering and Solar Carve-out Program Costs

For Massachusetts Electric Co. and Nantucket Electric Co.

Line		2014	2015	2016	2017	2018	2019	2020
1	Statewide Solar Installed, MW (DC)	705	975	1,195	1,315	1,415	1,535	1,600
2	National Grid Total Net Metering, MW (DC)	381	579	701	719	743	767	791
3	Nat. Grid Cost of Net Metering	$ 34,626,124	$ 71,064,601	$ 84,504,439	$ 102,112,044	$ 108,519,996	$ 110,909,698	$ 112,129,432
4	Nat. Grid Cost of SREC I	$ 52,146,219	$ 207,648,842	$ 174,795,852	$ 121,570,066	$ 110,995,561	$ 107,014,171	$ 103,450,654
5	Nat. Grid Cost of SREC II	$ 6,516,547	$ 20,766,316	$ 58,929,360	$ 87,064,372	$ 98,709,410	$ 107,166,366	$ 112,466,901
6	Total Cost of Solar Programs and Net Metering	$ 93,288,891	$ 299,479,759	$ 318,229,651	$ 310,746,481	$ 318,224,967	$ 325,090,235	$ 328,046,988
7	Residential Cost	$ 36,524,243	$ 113,894,614	$ 121,778,124	$ 120,555,153	$ 123,787,228	$ 126,461,831	$ 127,629,689
8	Low Income Cost	$ 5,497,932	$ 17,146,184	$ 18,332,581	$ 18,147,562	$ 18,633,916	$ 19,036,526	$ 19,212,317
9	Commercial and Industrial Cost	$ 51,266,716	$ 168,438,960	$ 178,118,946	$ 172,043,766	$ 175,803,824	$ 179,591,878	$ 181,204,981
	Average Cost per kWh							
10	Residential	$0.0048	$0.0150	$0.0161	$0.0159	$0.0164	$0.0167	$0.0169



National Grid Solar Program Installations and Cost Projection, 2014-2020
Nat. Grid Cost of Net Metering
Nat. Grid Cost of SREC I
Nat. Grid Cost of SREC II
Statewide Solar Installed, MW (DC)
National Grid Total Net Metering, MW (DC)
$350,000,000
$300,000,000
$250,000,000
$200,000,000
$150,000,000
$100,000,000
$50,000,000
$-
1,800
1,600
1,400
1,200
1,000
800
600
400
200
-
2014
2015
2016
2017
2018
2019
2020

National Grid Net Metering Cost Projections, 2014-2020

For Massachusetts Electric Co. and Nantucket Electric Co.

	2014	2015	2016	2017	2018	2019	2020
National Grid Net Metering (interconnected at year end)							
Total Capped Net Metering (kW AC)	243,805	390,160	461,790	461,790	461,790	461,790	461,790
Total Net Metering (kW AC)	318,200	483,660	585,290	600,290	620,290	640,290	660,290
Net Metered Generation							
Net Metered Generation, kWh (est.)	351,500,000	516,475,934	685,267,469	798,653,580	836,523,060	862,146,060	886,455,060
Percent Non-Coincident, annual	70.3%	72.0%	74.0%	75.0%	73.0%	72.0%	70.0%
Total Exported Net Metered kWh	247,109,650	371,862,673	507,097,927	598,990,185	610,661,834	620,745,163	620,518,542
National Grid Rates (based on current and estimated rates)							
Distribution Rate, average	0.05531	0.06012	0.06012	0.06012	0.06012	0.06012	0.06012
Energy Efficiency Charge	0.00827	0.00989	0.00989	0.00989	0.00989	0.00989	0.00989
Transmission	0.01868	0.02279	0.02279	0.02279	0.02279	0.02279	0.02279
Transition	0.00113	(0.00155)	0.00075	0.00059	0.00019	0.00016	0.00006
Basic Service, Annual Average	0.08740	0.12065	0.10000	0.11000	0.12000	0.12000	0.12000
Total Average kWh Rate	0.17079	0.21190	0.19354	0.20338	0.21298	0.21295	0.21285
Net Metering Costs							
Displaced Revenue	$ 6,636,928	$ 10,123,646	$ 12,472,753	$ 13,977,429	$ 15,811,407	$ 16,899,261	$ 18,616,877
Distribution, Exports	$ 13,666,917	$ 22,355,851	$ 30,486,001	$ 36,010,432	$ 36,712,114	$ 37,318,310	$ 37,304,686
Transmission, Exports	$ 4,615,572	$ 8,473,440	$ 11,554,975	$ 13,648,875	$ 13,914,831	$ 14,144,595	$ 14,139,431
Transition, Exports	$ 280,359	$ (574,643)	$ 380,323	$ 353,404	$ 116,026	$ 99,319	$ 37,231
Commodity, Exports	$ 21,596,468	$ 44,865,231	$ 50,709,793	$ 65,888,920	$ 73,279,420	$ 74,489,420	$ 74,462,225
Total Export Costs	$ 40,159,316	$ 75,119,879	$ 93,131,091	$ 115,901,631	$ 124,022,391	$ 126,051,643	$ 125,943,572
Total Net Meter Costs	$ 46,796,244	$ 85,243,525	$ 105,603,844	$ 129,879,061	$ 139,833,799	$ 142,950,905	$ 144,560,449
Net Metering Revenues							
Average annual ISO-NE LMP ($/kWh)	$ 0.049	$ 0.056	$ 0.055	$ 0.054	$ 0.054	$ 0.053	$ 0.054
Total revenue from generation	$ 12,170,120	$ 14,178,924	$ 21,099,405	$ 27,767,017	$ 31,313,802	$ 32,041,207	$ 32,431,017
Net Cost of Net Metering	$ 34,626,124	$ 71,064,601	$ 84,504,439	$ 102,112,044	$ 108,519,996	$ 110,909,698	$ 112,129,432

Cost by Customer Class

National Grid Estimated Cost of Solar Carve-Out Program, 2014-2020

For Massachusetts Electric Co. and Nantucket Electric Co.

	2014	2015	2016	2017	2018	2019	2020
Total Solar Carve-Out Capacity (kW DC)	705,153	975,153	1,195,153	1,315,153	1,415,153	1,535,153	1,600,000
SREC I	622,768	654,781	654,781	654,781	654,781	654,781	654,781
SREC II	82,385	320,373	540,373	660,373	760,373	880,373	945,219
Unit Prices							
SREC I	$ 260.00	$ 460.00	$ 440.00	$ 366.50	$ 355.50	$ 344.50	$ 334.50
SREC II	$ 375.00	$ 300.00	$ 280.00	$ 310.37	$ 303.73	$ 288.58	$ 273.90
Compliance Obligations							
SREC I	0.948%	2.144%	1.892%	1.580%	1.487%	1.479%	1.473%
SREC II	0.082%	0.329%	1.002%	1.336%	1.548%	1.768%	1.955%
Existing Requirements							
Volumes							
Basic Service Load	10,883,455	10,000,000	10,500,000	10,750,000	11,000,000	11,000,000	11,000,000
Total SREC I	103,186	214,420	198,632	169,802	163,546	162,714	161,998
Total SREC II	8,940	32,880	105,231	143,599	170,236	194,524	215,083
Cost for Basic Service Obligation							
SREC I	$ 26,828,370	$ 98,633,200	$ 87,397,926	$ 62,232,296	$ 58,140,532	$ 56,055,042	$ 54,188,438
SREC II	$ 3,352,656	$ 9,864,000	$ 29,464,680	$ 44,568,666	$ 51,704,929	$ 56,134,763	$ 58,911,234
Total Solar Carve Out	$ 30,181,026	$ 108,497,200	$ 116,862,606	$ 106,800,962	$ 109,845,461	$ 112,189,805	$ 113,099,672
Basic Service/Total Distribution	51%	48%	50%	51%	52%	52%	52%
Cost for All Distribution Customers							
SREC I	$ 52,146,219	$ 207,648,842	$ 174,795,852	$ 121,570,066	$ 110,995,561	$ 107,014,171	$ 103,450,654
SREC II	$ 6,516,547	$ 20,766,316	$ 58,929,360	$ 87,064,372	$ 98,709,410	$ 107,166,366	$ 112,466,901
Total	$ 58,662,766	$ 228,415,158	$ 233,725,212	$ 208,634,437	$ 209,704,971	$ 214,180,537	$ 215,917,555
Estimated Distribution Load	21,154,138	21,052,632	21,000,000	21,000,000	21,000,000	21,000,000	21,000,000
Average Cost per kWh	$0.0028	$0.0108	$0.0111	$0.0099	$0.0100	$0.0102	$0.0103

Massachusetts Electric Company
Nantucket Electric Company
January 2014 through December 2014

(KWH)	Total	R1/E	R2	R4	G1	G2	G3	STREETLIGHTS
TOTAL	21,154,138,569	7,613,252,679	1,148,104,603	11,543,795	2,183,741,240	2,827,374,878	7,234,723,638	135,397,736

Sales Allocator	
Residential	36%
Low Income	5%
Commercial and Industrial	59%
	100%
Distribution Revenue Allocator by Rate Class	
R-1/R-2	51.0%
R-4	0.1%
G-1	17.5%
G-2	10.5%
G-3	20.4%
Streetlights	0.5%
	100.0%
Total R-1/R-2	8,761,357,282
R-2	1,148,104,603
R-2%	13%
Low Income R-2 DRA	7%
Residential R-1 DRA	44%
Distribution Revenue Allocator by Customer Class	
Residential	44%
Low Income	7%
Commercial and Industrial	49%
	100%

	kWh	(247,109,650)
Charge Category	Factor Description	Sum of Amount
Commodity	Basic Service Adjustment Factor	$91,518.13
	Base Basic Service Charge	($21,670,714.36)
	Smart Grid Customer Cost Factor	($17,272.16)
Commodity Total		($21,596,468.39)
Distribution	Attorney General Consulting Expense	($427.02)
	Base Distribution Charge	($11,093,036.74)
	Pension/PBOP Adjustment Factor	($475,101.32)
	Residential Assistance Adjustment Factor	($969,080.91)
	Revenue Decoupling Mechanism Adjustment Factor	($226,934.64)
	Solar Cost Adjustment Factor	($40,066.75)
	Storm Cost Recovery Factor	($694,784.21)
	Smart Grid Distribution Adjustment Factor	($1,099.91)
	Basic Service Administrative Cost Factor	($166,568.19)
	Default Service Cost Reclassification Adjustment Factor	$182.46
Distribution Total		($13,666,917.23)
Transition	Base Transition Charge	($254,740.49)
	Transition Adjustment Factor	($25,618.07)
Transition Total		($280,358.56)
Transmission	Base Transmission Charge	($4,398,908.22)
	Transmission Service Adjustment Factor	($216,663.75)
Transmission Total		($4,615,571.97)
		($40,159,316.15)

Average Rate per kWh 2014

	R1	Regular Residential	7,571,457	Di:
	R2	Low Income Residential	95,252	
	G1	General Service - Small C&I	228,380,971	
	G2	General Service - Demand	3,563,584	
$0.08740	G3	Time-of-Use	7,498,386	
			247,109,650	Average Rate
$0.04489				Base
				Total

$0.05531

$0.00113

$0.01868

stribution 2015*	Transition 2015	Transmission 2015	EE 2014	EE 2015
$0.01254	($0.00164)	$0.02614	0.009833	0.014173
$0.01254	($0.00164)	$0.02614	0.003620	0.003620
$0.01573	($0.00154)	$0.02276	0.008223	0.009753
$0.00830	($0.00163)	$0.02229	0.008223	0.009753
$0.00596	($0.00157)	$0.02040	0.008223	0.009753
$0.0152	**($0.00155)**	**$0.02279**	**0.008271**	**0.009886**
$0.04489				
$0.06012				

*reflects reconciling factors in effect March 15 or pending approval

Transition Rates

2016	$/kWh	MWH	$
MECO	$0.00081	22,229	$17,971,484
EE	$0.00040	3,481	$1,392,872
Total	**$0.00075**	25,710	$19,364,356
2017			
MECO	$0.00064	22,562	$14,404,560
EE	$0.00033	3,524	$1,172,137
Total	**$0.00059**	26,087	$15,576,698
2018			
MECO	$0.00017	22,901	$3,963,730
EE	$0.00032	3,561	$1,137,315
Total	**$0.00019**	26,462	$5,101,046
2019			
MECO	$0.00014	23,244	$3,282,687
EE	$0.00031	3,616	$1,103,084
Total	**$0.00016**	26,861	$4,385,771
2020			
MECO	$0.00003	23,593	$774,358
EE	$0.00026	3,662	$934,877
Total	**$0.00006**	27,255	$1,709,235

April 5, 2015

VIA ELECTRONIC MAIL

Dear Chairs O'Connor and Burgess,

The undersigned members of the Net Metering and Solar Task Force (NMTF) respectfully register our concern over the information request issued by Chair O'Connor to the utility representatives of the NMTF on April 2, 2015 calling for an estimation of the total cost of the solar program from 2014 through 2020, including an analysis of the "cost shift" associated with net metering borne by non-participating customers. While we understand and support the Chair's desire for better documentation of the direct economic impacts of the solar program, we believe the request is too narrowly focused to serve as a basis for action. Our concern with the information request is twofold.

First, as should be clear from the Task Force discussions to date, the issue of whether and the extent to which the costs of the solar program exceed the benefits, and who bears those costs and benefits, have been the most hotly contested and challenging issues confronting the representatives. However, there appears to be a fair degree of consensus (if not unanimity) around the view that any policy recommendation regarding a future incentive and net metering framework be grounded in a comprehensive analysis of solar costs <u>and</u> benefits. Our concern with the Chair's request is that it is focused on a review of ratepayer costs without seeking information on countervailing ratepayer benefits, let alone broader societal benefits associated with greater reliance on solar generation as part of the Commonwealth's resource mix. Moreover, it appears to presume an inappropriate cost shift between customers who are net metering and those who are not, without analyzing offsetting benefits to those not net metering and to the system as a whole. A narrow focus on the gross costs of Massachusetts' solar program presents only a part of the picture and will not contribute to a constructive dialogue around future program design.

Our second objection to the Chair's request is that it is directed to a subset of the NMTF members. While it could be argued that the utilities are uniquely positioned to provide information on the distributional effects of net metering, the same cannot be said with respect to the SREC program. In any event, given the utilities' articulated position on this issue, we believe it would be more appropriate for this analysis to be conducted by an independent third party - whether that be by DPU and DOER staff or outside consultants. This is not meant as a criticism of the utility representatives; we have made no secret of our own strong view that a full accounting of benefits may well reveal that it is the solar customer who is subsidizing other ratepayers. The point is simply that, given our respective positions and interests, a better course would be to assign this critical task to a neutral third party.

In sum, the undersigned members of the NMTF wish to underscore our support for a better understanding of solar benefits and costs as foundational to policy development in that arena. For that reason, we believe the policy framework offered to the legislature should recommend that a comprehensive solar benefit/cost study be conducted, perhaps under the auspices of the NMTF. Given the narrowly focused nature of the Chair's request, however, we have real reservations about the direction of this analysis and its potential use in the report ultimately delivered to the legislature.

Respectfully submitted,

Larry Aller
NEXT STEP LIVING

Janet Gail Besser
NEW ENGLAND CLEAN ENERGY COUNCIL

David Colton
MASSACHUSETTS MUNICIPAL ASSOCIATION

Lisa Podgurski
INTERNATIONAL BROTHERHOOD OF ELECTRICAL WORKERS

William Stillinger
SOLAR ENERGY BUSINESS ASSOCIATION OF NEW ENGLAND

Fred Zalcman
SOLAR ENERGY INDUSTRIES ASSOCIATION

[redacted]

From: Burgess, Dan (ENE)
Sent: Thursday, April 16, 2015 5:20 PM
To: Burgess, Dan (ENE)
Subject: Clarifying Questions on Utility Information

Dear Task Force Members,

As discussed at today's meeting, below are the following questions for the utilities related to the data analysis provided in response to Chair O'Connor's April 2nd request for information:

Clarifying Questions for Both Utilities

1. Have you included in your analysis a consideration of the SREC I and SREC II compliance exemptions provided in 225 CMR 14.07(2)(a)4 through 5 and 225 CMR 14.07(3)(b)?
2. Have you included in your analysis a consideration of avoided Class I compliance costs that occur as a result of higher SREC I and SREC II obligations?
3. The estimated average SREC costs seem to indicate that you expect the SREC I and SREC II markets to be undersupplied from 2017-2020. Is this a correct interpretation and as an alternative, would a range of SREC prices be feasible?
4. Can you clarify that you have included all load served to distribution customers in your analysis of SREC compliance costs and not just the load you serve to basic service customers, on which your compliance obligations are based?

Additional Question for Eversource

1. Can Eversource define the distinction between "Displaced Load" and "System Load Reduction" and explain why the former is counted as a cost to customers?

Additional Question for National Grid

1. In Eversource's analysis of net metering costs it included "System Load Reduction" as a line item that reduced costs by a $/kWh rate equivalent to Basic Service. It does not appear as though National Grid included this in its analysis. Can you please clarify if this was in fact included?

To the extent possible, we ask the utilities to coordinate with each other to make sure there are consistent assumptions. Thank you for providing answers to these questions.

Thanks,
Dan

Dan Burgess
Acting Commissioner
Massachusetts Department of Energy Resources
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April 23, 2015

Net Metering and Solar Task Force
Attn: Co-Chairs Angela O'Connor and Daniel Burgess
RE: Response for Information Request

Dear Ms. O'Connor and Mr. Burgess:

Eversource is pleased to provide the following responses to questions relating to the data analysis provided in response to Chair O'Connor's April 2nd request for information and has attached a revised estimate of total solar net metering and solar RPS costs.

Have you included in your analysis a consideration of the SREC I and SREC II compliance exemptions provided in 225 CMR 14.07(2)(a)4 through 5 and 225 CMR 14.07(3)(b)?

We did not consider SREC I and SREC II compliance exemptions in our analysis. The impact of these exemptions has been estimated in the revised analysis provided with this response and results in less than a 3% reduction in Solar RPS costs over the forecast period.

Have you included in your analysis a consideration of avoided Class I compliance costs that occur as a result of higher SREC I and SREC II obligations?

We did not consider the displacement of lower cost Class I certificate obligations as a result of SREC I and SREC II obligations as it is not relevant to the analysis. Eversource provided the estimate of total Solar net metering and Solar RPS costs for our customers. Our analysis did not seek to quantify other costs or benefits associated with the solar program relative to other renewable policy choices. Such cost/benefit analysis is being performed by the Consultant.

The estimated average SREC costs seem to indicate that you expect the SREC I and SREC II markets to be undersupplied from 2017-2020. Is this a correct interpretation and as an alternative, would a range of SREC prices be feasible?

We do not have any expectations as to whether the SREC I and SREC II markets will be undersupplied or oversupplied and we did not attempt to forecast SREC prices. Cost estimates are based on recent market pricing of 2014-2016 SRECs and the average of the net auction price and the ACP rate in each year from 2017-2020.

It would certainly be feasible to generate several estimates based on a range of prices. We would expect our estimates from 2017-2020 would be an approximate midpoint of the likely range of estimates.

Eversource can further update its analysis with the Task Force consultant's projections of solar RPS compliance obligations and SREC prices once they are available and have been reviewed by the Task Force.

Can you clarify that you have included all load served to distribution customers in your analysis of SREC compliance costs and not just the load you serve to basic service customers, on which your compliance obligations are based?

That's correct, we estimated the costs paid by all customers through delivery and generation rates to support solar net metering and comply with solar RPS requirements.

Can Eversource define the distinction between "Displaced Load" and "System Load Reduction" and explain why the former is counted as a cost to customers?

Displaced Load refers to consumption that is directly offset by onsite generation. Displaced load results in neither a load obligation nor settlement of excess generation. Displaced load does result in a reduction in revenue collected through transmission and distribution charges and all reconciling rate mechanisms ("rate trackers"), which is then recovered from remaining customers through the net metering recovery surcharge or revenue decoupling mechanism and increases to other rate trackers. Our analysis accounts for this cost by multiplying displaced load by the transmission and distribution rate components including all applicable reconciling rates.

System Load Reduction refers to onsite generation that exceeds onsite consumption. This excess generation is not explicitly reported to ISO-NE for wholesale settlement. For the purposes of this analysis, the Company assumes this generation results in a reduction to wholesale load obligations that is spread amongst all customers.

Please let us know if there are any additional questions on the analysis

Kind Regards,

Camilo Serna

Eversource Solar RPS & Net Metering Cost Summary

	2014	2015	2016	2017	2018	2019	2020
Distribution Load (MWh)							
Gross Load (MWh)	25,741,623	26,037,001	26,001,219	25,854,714	25,574,650	25,355,855	25,149,735
Less: Net Metered Solar Generation	(237,299)	(391,393)	(502,159)	(630,344)	(714,656)	(770,829)	(808,297)
Net Load (MWh)	25,504,324	25,645,608	25,499,060	25,224,370	24,859,994	24,585,026	24,341,438
Solar % of Load	*0.9%*	*1.5%*	*1.9%*	*2.4%*	*2.8%*	*3.0%*	*3.2%*
Total Cost to Support Solar Generation ($M)							
Net Metering	20.8	41.9	46.8	62.4	75.3	81.7	87.8
RPS	77.9	261.7	286.7	252.0	246.8	249.7	249.7
Total	98.7	303.7	333.4	314.5	322.1	331.4	337.6
Total Solar Cost by Customer Class ($M)							
Residential	32.3	96.8	106.3	102.5	106.4	110.0	112.5
Low Income	3.0	9.0	9.9	9.6	9.9	10.3	10.5
Commercial & Industrial	63.4	197.9	217.2	202.4	205.8	211.2	214.5
Total	98.7	303.7	333.4	314.5	322.1	331.4	337.6
Rate Impact by Customer Class (c/kWh)							
Residential	0.4	1.3	1.4	1.4	1.4	1.5	1.5
Low Income	0.4	1.3	1.4	1.4	1.4	1.5	1.6
Commercial & Industrial	0.4	1.2	1.3	1.2	1.2	1.3	1.3

Eversource Net Metering Analysis

	2014	2015	2016	2017	2018	2019	2020
Distribution Load (MWh)							
Gross Load (MWh)	25,741,623	26,037,001	26,001,219	25,854,714	25,574,650	25,355,855	25,149,735
Less: Solar Generation	(237,299)	(391,393)	(502,159)	(630,344)	(714,656)	(770,829)	(808,297)
Net Load (MWh)	25,504,324	25,645,608	25,499,060	25,224,370	24,859,994	24,585,026	24,341,438
Solar % of Load	*0.9%*	*1.5%*	*1.9%*	*2.4%*	*2.8%*	*3.0%*	*3.2%*
Average Net Metering Rate Components (c/kWh)							
Energy (Basic Service)	9.4	12.2	9.6	10.7	12.0	12.3	13.1
Transmission	2.4	2.1	2.1	2.1	2.1	2.1	2.0
Transition	0.4	0.1	0.1	0.1	0.1	0.1	0.1
Distribution	5.3	5.3	5.4	5.4	5.4	5.4	5.4
DSM	0.25	0.25	0.25	0.25	0.25	0.25	0.25
Generation by Segment (MWh)							
Displaced Load	89,844	146,286	193,232	238,474	272,620	298,317	321,789
Excess Generation							
Class I, II & III (Public)	131,623	213,615	261,853	322,150	352,623	365,575	364,936
Class III (Private)	15,832	31,492	47,073	69,720	89,412	106,937	121,573
Total Net Metering Credit by Segment ($M)							
Displaced T&D Credit	7.5	11.4	15.1	18.6	21.3	23.4	25.3
Excess Generation Credit							
Class I, II & III (Public)	23.0	42.1	45.0	58.8	69.0	72.6	75.5
Class III (Private)	1.9	4.5	5.6	9.0	12.7	15.5	18.6
Total Net Metering Credits ($M)	**32.4**	**58.0**	**65.6**	**86.5**	**103.1**	**111.4**	**119.4**
Settlement Value (c/kWh)							
System Load Reduction	9.4	12.2	9.6	10.7	12.0	12.3	13.1
Wholesale Settlement	7.6	5.6	5.5	5.4	5.4	5.3	5.4
Excess Generation by Use (MWh)							
System Load Reduction	21,646	35,472	44,927	54,423	61,359	66,412	70,706
Wholesale Settlement	125,809	209,636	263,999	337,448	380,676	406,099	415,802
Total Settlement Value ($M)	**(11.6)**	**(16.1)**	**(18.9)**	**(24.1)**	**(27.8)**	**(29.7)**	**(31.6)**
Total Net Metering Cost Shift ($M)	**20.8**	**41.9**	**46.8**	**62.4**	**75.3**	**81.7**	**87.8**
Net Metering Cost by Customer Class							
Total ($M)							
Residential	8.8	17.7	19.8	26.4	31.8	34.5	37.1
Low Income	0.8	1.7	1.9	2.5	3.0	3.3	3.5
Commercial & Industrial	11.2	22.5	25.1	33.5	40.4	43.9	47.2
Rate Impact (c/kWh)							
Residential	0.11	0.23	0.26	0.35	0.43	0.47	0.51
Low Income	0.12	0.24	0.26	0.36	0.44	0.48	0.52
Commercial & Industrial	0.07	0.13	0.15	0.20	0.24	0.27	0.29

Customer Class Allocation Factors

Revenue	
Residential	42%
Low Income	4%
Commercial & Industrial	54%
Sales	
Residential	30%
Low Income	3%
Commercial & Industrial	67%

Eversource Solar RPS Analysis

	2014	2015	2016	2017	2018	2019	2020
Compliance Obligation							
SREC I	0.9481%	2.1442%	1.90%	1.58%	1.48%	1.47%	1.47%
SREC II	0.0843%	0.3288%	1.00%	1.34%	1.55%	1.77%	1.96%
Total	1.032%	2.473%	2.90%	2.91%	3.02%	3.24%	3.42%
SREC Price ($/MWh)							
SREC I	289	428	446	371	356	345	335
SREC II	371	310	275	309	303	288	273
Total Solar RPS Cost ($M) [1]							
SREC I	69.9	235.6	216.4	147.9	130.4	124.6	119.6
SREC II	8.0	26.1	70.3	104.2	116.4	125.1	130.1
Total	**77.9**	**261.7**	**286.7**	**252.0**	**246.8**	**249.7**	**249.7**
Solar RPS Rate Impact (c/kWh)							
SREC I	0.28	0.92	0.85	0.59	0.53	0.51	0.49
SREC II	0.03	0.10	0.28	0.42	0.47	0.51	0.54
Total	0.31	1.03	1.13	1.01	1.00	1.02	1.03
Solar RPS Costs by Customer Class ($M)							
Residential	23.5	79.0	86.6	76.1	74.5	75.4	75.4
Low Income	2.2	7.3	8.0	7.1	6.9	7.0	7.0
Commercial & Industrial	52.2	175.4	192.1	168.9	165.4	167.3	167.3
Total	77.9	261.7	286.7	252.0	246.8	249.7	249.7

[1] Excludes Solar RPS included in Net Metering costs

Line Loss Factor 0.66%

Eversource Net Metering Capacity & Generation

	2014	2015	2016	2017	2018	2019	2020
Net Metered Capacity (Est. Nameplate MW)							
Non-Solar	34.1	34.1	34.1	34.1	34.1	34.1	34.1
Solar (Capped)	177.8	322.6	388.2	470.6	525.2	562.9	566.5
Solar (Exempt)	46.1	72.3	98.5	111.6	129.1	146.6	164.1
Total	258.0	429.1	520.8	616.4	688.4	743.6	764.7
Generation by Settlement (MWh)							
Consumed Onsite	89,844	146,286	193,232	238,474	272,620	298,317	321,789
System Load Reduction	21,646	35,472	44,927	54,423	61,359	66,412	70,706
Wholesale Settlement	125,809	209,636	263,999	337,448	380,676	406,099	415,802
Total [1]	237,299	391,393	502,159	630,344	714,656	770,829	808,297
Excess Generation by Class (MWh)							
Class I	11,645	18,768	25,455	31,198	35,937	39,716	43,557
Class II	51,762	83,838	105,062	133,741	150,610	160,302	163,309
Class III (Public)	68,216	111,009	131,336	157,211	166,076	165,557	158,070
Class III (Private)	15,832	31,492	47,073	69,720	89,412	106,937	121,573
Total	147,455	245,107	308,927	391,870	442,035	472,511	486,508
% of Load	0.9%	1.5%	1.9%	2.4%	2.8%	3.0%	3.2%

[1] Excludes parasitic station load

Information Requests:

Clarifying Questions for Both Utilities

1. Have you included in your analysis a consideration of the SREC I and SREC II compliance exemptions provided in 225 CMR 14.07(2)(a)4 through 5 and 225 CMR 14.07(3)(b)?
2. Have you included in your analysis a consideration of avoided Class I compliance costs that occur as a result of higher SREC I and SREC II obligations?
3. The estimated average SREC costs seem to indicate that you expect the SREC I and SREC II markets to be undersupplied from 2017-2020. Is this a correct interpretation and as an alternative, would a range of SREC prices be feasible?
4. Can you clarify that you have included all load served to distribution customers in your analysis of SREC compliance costs and not just the load you serve to basic service customers, on which your compliance obligations are based?

Additional Question for National Grid

1. In Eversource's analysis of net metering costs it included "System Load Reduction" as a line item that reduced costs by a $/kWh rate equivalent to Basic Service. It does not appear as though National Grid included this in its analysis. Can you please clarify if this was in fact included?

National Grid Response:

1) The utilities considered but did not include in the initial cost analysis pre-contracted competitive service load, which is exempt from some of the SREC requirements, but it did not materially affect the total cost projection. For comparison, and for use in the appendix of the Task Force report, National Grid removed the exempt load to use the same projection as Eversource for the adjusted total SREC compliance obligation, and recalculated the projected costs for all distribution customers. This is now reflected in the "SREC Costs" sheet, shaded in light blue, and in the "Summary" sheet figures.

2) No, avoided Class I REC costs are not included as a credit against the overall costs.

3) For this cost analysis, we did not project undersupply or oversupply because the pace of growth and the annual compliance requirement are both uncertain. We used a midrange cost estimate by averaging the upper and lower expected bounds of pricing for SRECs. Prices are likely to be volatile for SREC II compliance, as they have been for

SREC I compliance, and thus a midpoint or mean estimate is more appropriate to show the impact of potential volatility.

National Grid can recalculate the total cost using the projection of spot market prices by the consultants to the Task Force once their price and obligation projection becomes available.

4) Yes, the total figures in the summary show costs applicable to all National Grid customers for SREC costs. We also present our estimates of Basic Service only costs for SRECs on lines 11 and 12 of the "SREC Costs" worksheet. By doing so, this projection provides important information about relative magnitudes of costs for all customers, regardless of how they buy their supply.

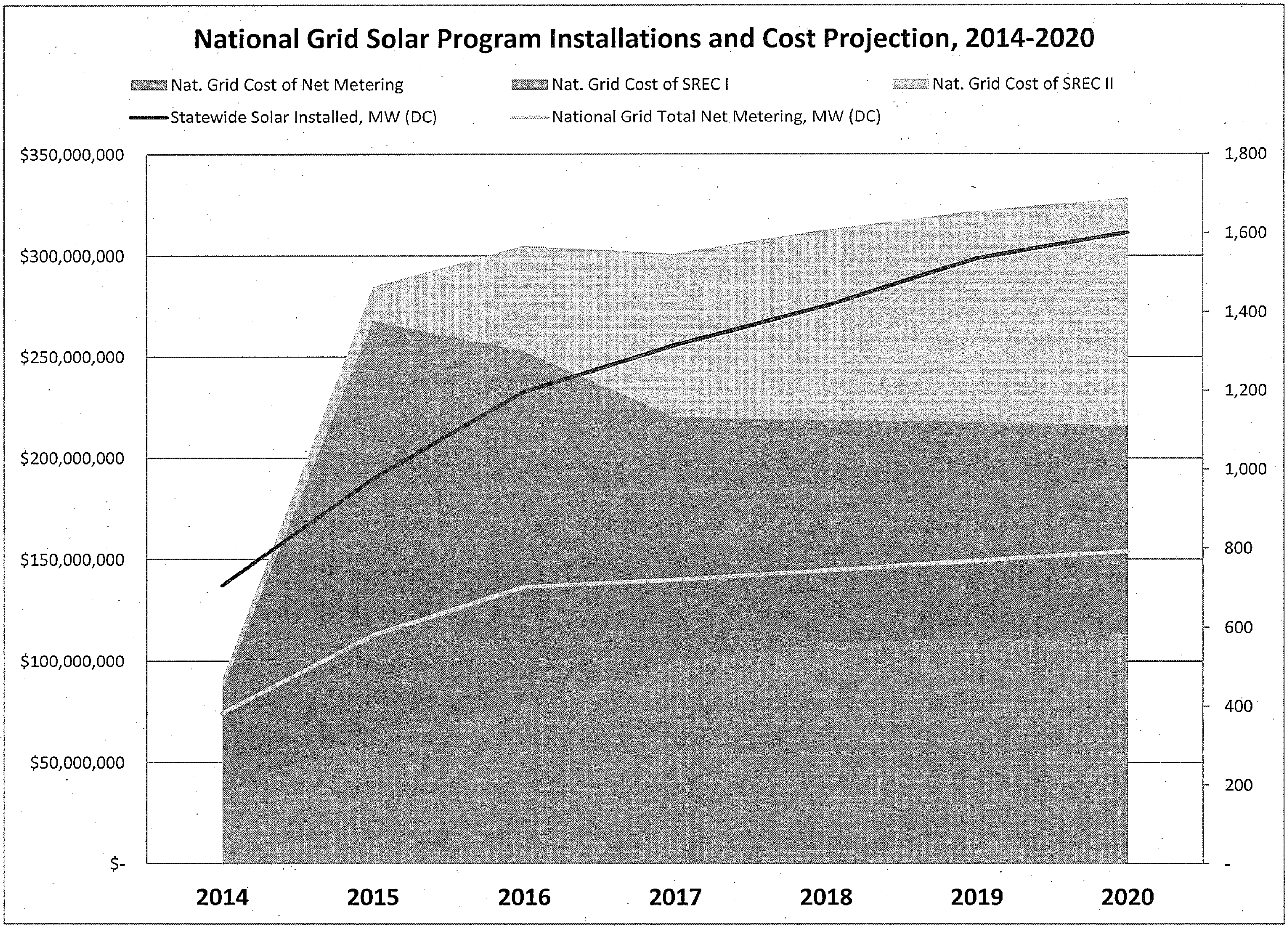
Additional Question for National Grid:

1) National Grid understands the "System Load Reduction" volume shown on the Eversource estimate to be those kilowatt-hours that are exported by net metered systems but that are not settled with ISO-NE as Settlement Only Generators. National Grid also has net metered systems under 60 kW that do not settle their exports with ISO-NE on its system. The estimated amount of exported but unsettled kWh is now shown for 2014 in cell C13 on the "Net Metering Costs" sheet, in the attached Excel workbook, "NMTF Request – National Grid Solar and Net Metering Costs 2014-2020 Revised." These kWh have now also been removed from the calculation of the average wholesale value received in 2014, in cell C34, Line 20. The amount of unsettled exported generation was approximately 3.3% of the total net metered generation in 2014, and we use this percentage to then estimate the amount of such exports in future years, on Line 6. This energy may create reductions in some costs to supply customers, such as reduced losses, but are not monetized directly in reduced payments to suppliers or sales to ISO-NE. They therefore are not accounted any value as a credit in this analysis. Separately, National Grid has made a change in the calculations of wholesale revenue from exports that are settled, to better reflect the value of exports in the year generated. These two changes – removing unsettled load estimates and calculating with current year instead of prior year volumes – reduce the net cost of net metering slightly in the projection, shown on Line 22, and on the "Summary" sheet.

National Grid Summary of Installations, Net Metering and Solar Carve-out Program Costs

For Massachusetts Electric Co. and Nantucket Electric Co.

Line		2014	2015	2016	2017	2018	2019	2020
1	Statewide Solar Installed, MW (DC)	705	975	1,195	1,315	1,415	1,535	1,600
2	National Grid Total Net Metering, MW (DC)	381	579	701	719	743	767	791
3	Nat. Grid Cost of Net Metering	$ 34,626,124	$ 65,364,628	$ 78,857,285	$ 98,941,544	$ 108,517,877	$ 111,441,802	$ 112,787,009
4	Nat. Grid Cost of SREC I	$ 51,773,571	$ 202,547,829	$ 173,994,897	$ 121,028,493	$ 110,066,642	$ 106,381,347	$ 103,169,807
5	Nat. Grid Cost of SREC II	$ 4,312,554	$ 16,797,267	$ 51,901,541	$ 81,019,765	$ 94,145,067	$ 103,976,408	$ 112,467,884
6	Total Cost of Solar Programs and Net Metering	$ 90,712,250	$ 284,709,724	$ 304,753,723	$ 300,989,802	$ 312,729,586	$ 321,799,557	$ 328,424,701
7	Residential Cost	$ 35,595,519	$ 108,093,652	$ 116,448,033	$ 116,772,994	$ 121,806,295	$ 125,320,292	$ 127,820,890
8	Low Income Cost	$ 5,358,089	$ 16,272,985	$ 17,530,281	$ 17,578,220	$ 18,335,637	$ 18,864,613	$ 19,241,074
9	Commercial and Industrial Cost	$ 49,758,642	$ 160,343,086	$ 170,775,410	$ 166,638,588	$ 172,587,654	$ 177,614,653	$ 181,362,736
	Average Cost per kWh							
10	Residential	$0.0047	$0.0142	$0.0154	$0.0154	$0.0161	$0.0166	$0.0169


National Grid Solar Program Installations and Cost Projection, 2014-2020
Nat. Grid Cost of Net Metering
Nat. Grid Cost of SREC I
Nat. Grid Cost of SREC II
Statewide Solar Installed, MW (DC)
National Grid Total Net Metering, MW (DC)
$350,000,000
$300,000,000
$250,000,000
$200,000,000
$150,000,000
$100,000,000
$50,000,000
$-
1,800
1,600
1,400
1,200
1,000
800
600
400
200
-
2014
2015
2016
2017
2018
2019
2020

National Grid Net Metering Cost Projections, 2014-2020

For Massachusetts Electric Co. and Nantucket Electric Co.

	2014	2015	2016	2017	2018	2019	2020
National Grid Net Metering (interconnected at year end)							
Total Capped Net Metering (kW AC)	243,805	390,160	461,790	461,790	461,790	461,790	461,790
Total Net Metering (kW AC)	318,200	483,660	585,290	600,290	620,290	640,290	660,290
Net Metered Generation							
Net Metered Generation, kWh (est.)	351,500,000	516,475,934	685,267,469	798,653,580	836,523,060	862,146,060	886,455,060
Percent Non-Coincident, annual	70.3%	72.0%	74.0%	75.0%	73.0%	72.0%	70.0%
Total Exported Net Metered kWh	247,109,650	371,862,673	507,097,927	598,990,185	610,661,834	620,745,163	620,518,542
Total Exported kWh, Not Settled	11,738,650	17,043,706	22,613,826	26,355,568	27,605,261	28,450,820	29,253,017
National Grid Rates (based on current and estimated rates)							
Distribution Rate, average	0.05531	0.06012	0.06012	0.06012	0.06012	0.06012	0.06012
Energy Efficiency Charge	0.00827	0.00989	0.00989	0.00989	0.00989	0.00989	0.00989
Transmission	0.01868	0.02279	0.02279	0.02279	0.02279	0.02279	0.02279
Transition	0.00113	(0.00155)	0.00075	0.00059	0.00019	0.00016	0.00006
Basic Service, Annual Average	0.08740	0.12065	0.10000	0.11000	0.12000	0.12000	0.12000
Total Average kWh Rate	0.17079	0.21190	0.19354	0.20338	0.21298	0.21295	0.21285
Net Metering Costs							
Displaced Revenue	$ 6,636,928	$ 10,123,646	$ 12,472,753	$ 13,977,429	$ 15,811,407	$ 16,899,261	$ 18,616,877
Distribution, Exports	$ 13,666,917	$ 22,355,851	$ 30,486,001	$ 36,010,432	$ 36,712,114	$ 37,318,310	$ 37,304,686
Transmission, Exports	$ 4,615,572	$ 8,473,440	$ 11,554,975	$ 13,648,875	$ 13,914,831	$ 14,144,595	$ 14,139,431
Transition, Exports	$ 280,359	$ (574,643)	$ 380,323	$ 353,404	$ 116,026	$ 99,319	$ 37,231
Commodity, Exports	$ 21,596,468	$ 44,865,231	$ 50,709,793	$ 65,888,920	$ 73,279,420	$ 74,489,420	$ 74,462,225
Total Export Costs	$ 40,159,316	$ 75,119,879	$ 93,131,091	$ 115,901,631	$ 124,022,391	$ 126,051,643	$ 125,943,572
Total Net Meter Costs	$ 46,796,244	$ 85,243,525	$ 105,603,844	$ 129,879,061	$ 139,833,799	$ 142,950,905	$ 144,560,449
Net Metering Revenues							
Average annual ISO-NE LMP ($/kWh)	$ 0.052	$ 0.056	$ 0.055	$ 0.054	$ 0.054	$ 0.053	$ 0.054
Total revenue from generation	$ 12,170,120	$ 19,878,897	$ 26,746,559	$ 30,937,516	$ 31,315,922	$ 31,509,103	$ 31,773,440
Net Cost of Net Metering	$ 34,626,124	$ 65,364,628	$ 78,857,285	$ 98,941,544	$ 108,517,877	$ 111,441,802	$ 112,787,009

Cost by Customer Class

National Grid Estimated Cost of Solar Carve-Out Program, 2014-2020

For Massachusetts Electric Co. and Nantucket Electric Co.

	2014	2015	2016	2017	2018	2019	2020
Total Solar Carve-Out Capacity (kW DC)	705,153	975,153	1,195,153	1,315,153	1,415,153	1,535,153	1,600,000
SREC I	622,768	654,781	654,781	654,781	654,781	654,781	654,781
SREC II	82,385	320,373	540,373	660,373	760,373	880,373	945,219
Unit Prices							
SREC I	$ 260.00	$ 460.00	$ 440.00	$ 366.50	$ 355.50	$ 344.50	$ 334.50
SREC II	$ 375.00	$ 300.00	$ 280.00	$ 310.37	$ 303.73	$ 288.58	$ 273.90
Compliance Obligations							
SREC I	0.948%	2.144%	1.892%	1.580%	1.487%	1.479%	1.473%
SREC II	0.082%	0.329%	1.002%	1.336%	1.548%	1.768%	1.955%
Existing Requirements							
Volumes							
Basic Service Load	10,883,455	10,000,000	10,500,000	10,750,000	11,000,000	11,000,000	11,000,000
Total SREC I	103,186	214,420	198,632	169,802	163,546	162,714	161,998
Total SREC II	8,940	32,880	105,231	143,599	170,236	194,524	215,083
Cost for Basic Service Obligation							
SREC I	$ 26,828,370	$ 98,633,200	$ 87,397,926	$ 62,232,296	$ 58,140,532	$ 56,055,042	$ 54,188,438
SREC II	$ 3,352,656	$ 9,864,000	$ 29,464,680	$ 44,568,666	$ 51,704,929	$ 56,134,763	$ 58,911,234
Total Solar Carve Out	$ 30,181,026	$ 108,497,200	$ 116,862,606	$ 106,800,962	$ 109,845,461	$ 112,189,805	$ 113,099,672
Basic Service/Total Distribution	51%	48%	50%	51%	52%	52%	52%
Estimated Distribution Load	21,154,138	21,052,632	21,000,000	21,000,000	21,000,000	21,000,000	21,000,000
Adjusted SREC I Obligation (no exempt load)	0.941%	2.092%	1.883%	1.573%	1.474%	1.470%	1.469%
Adjusted SREC II Obligation (no exempt load)	0.054%	0.266%	0.883%	1.243%	1.476%	1.716%	1.955%
Cost for All Distribution Customers							
SREC I	$ 51,773,571	$ 202,547,829	$ 173,994,897	$ 121,028,493	$ 110,066,642	$ 106,381,347	$ 103,169,807
SREC II	$ 4,312,554	$ 16,797,267	$ 51,901,541	$ 81,019,765	$ 94,145,067	$ 103,976,408	$ 112,467,884
Total	$ 56,086,126	$ 219,345,096	$ 225,896,438	$ 202,048,258	$ 204,211,709	$ 210,357,755	$ 215,637,691
Average Cost per kWh	$0.0027	$0.0104	$0.0108	$0.0096	$0.0097	$0.0100	$0.0103

Massachusetts Electric Company
Nantucket Electric Company
January 2014 through December 2014

(KWH)	Total	R1/E	R2	R4	G1	G2	G3	STREETLIGHTS
TOTAL	21,154,138,569	7,613,252,679	1,148,104,603	11,543,795	2,183,741,240	2,827,374,878	7,234,723,638	135,397,736
Sales Allocator								
Residential	36%							
Low Income	5%							
Commercial and Industrial	59%							
	100%							
Distribution Revenue Allocator by Rate Class								
R-1/R-2	51.0%							
R-4	0.1%							
G-1	17.5%							
G-2	10.5%							
G-3	20.4%							
Streetlights	0.5%							
	100.0%							
Total R-1/R-2	8,761,357,282							
R-2	1,148,104,603							
R-2%	13%							
Low income R-2 DRA	7%							
Residential R-1 DRA	44%							
Distribution Revenue Allocator by Customer Class								
Residential	44%							
Low Income	7%							
Commercial and Industrial	49%							
	100%							

	kWh	(247,109,650)
Charge Category	Factor Description	Sum of Amount
Commodity	Basic Service Adjustment Factor	$91,518.13
	Base Basic Service Charge	($21,670,714.36)
	Smart Grid Customer Cost Factor	($17,272.16)
Commodity Total		($21,596,468.39)
Distribution	Attorney General Consulting Expense	($427.02)
	Base Distribution Charge	($11,093,036.74)
	Pension/PBOP Adjustment Factor	($475,101.32)
	Residential Assistance Adjustment Factor	($969,080.91)
	Revenue Decoupling Mechanism Adjustment Factor	($226,934.64)
	Solar Cost Adjustment Factor	($40,066.75)
	Storm Cost Recovery Factor	($694,784.21)
	Smart Grid Distribution Adjustment Factor	($1,099.91)
	Basic Service Administrative Cost Factor	($166,568.19)
	Default Service Cost Reclassification Adjustment Factor	$182.46
Distribution Total		($13,666,917.23)
Transition	Base Transition Charge	($254,740.49)
	Transition Adjustment Factor	($25,618.07)
Transition Total		($280,358.56)
Transmission	Base Transmission Charge	($4,398,908.22)
	Transmission Service Adjustment Factor	($216,663.75)
Transmission Total		($4,615,571.97)
		($40,159,316.15)

Average Rate per kWh 2014

				Di:
	R1	Regular Residential	7,571,457	
	R2	Low Income Residential	95,252	
	G1	General Service - Small C&I	228,380,971	
	G2	General Service - Demand	3,563,584	
$0.08740	G3	Time-of-Use	7,498,386	
			247,109,650	Average Rate
$0.04489				Base
				Total

$0.05531

$0.00113

$0.01868

stribution 2015*	Transition 2015	Transmission 2015	EE 2014	EE 2015
$0.01254	($0.00164)	$0.02614	0.009833	0.014173
$0.01254	($0.00164)	$0.02614	0.003620	0.003620
$0.01573	($0.00154)	$0.02276	0.008223	0.009753
$0.00830	($0.00163)	$0.02229	0.008223	0.009753
$0.00596	($0.00157)	$0.02040	0.008223	0.009753
$0.0152	**($0.00155)**	**$0.02279**	**0.008271**	**0.009886**
$0.04489				
$0.06012				

*reflects reconciling factors in effect March 15 or pending approval

Transition Rates

2016	$/kWh	MWH	$
MECO	$0.00081	22,229	$17,971,484
EE	$0.00040	3,481	$1,392,872
Total	**$0.00075**	25,710	$19,364,356
2017			
MECO	$0.00064	22,562	$14,404,560
EE	$0.00033	3,524	$1,172,137
Total	**$0.00059**	26,087	$15,576,698
2018			
MECO	$0.00017	22,901	$3,963,730
EE	$0.00032	3,561	$1,137,315
Total	**$0.00019**	26,462	$5,101,046
2019			
MECO	$0.00014	23,244	$3,282,687
EE	$0.00031	3,616	$1,103,084
Total	**$0.00016**	26,861	$4,385,771
2020			
MECO	$0.00003	23,593	$774,358
EE	$0.00026	3,662	$934,877
Total	**$0.00006**	27,255	$1,709,235

Appendix E: Other Documents

Additional documents related to the efforts of the Task Force can be found on the following webpage:

http://www.mass.gov/eea/energy-utilities-clean-tech/nms-taskforce/previous-meetings.html

These documents include the following:

- Public Comments
- Task Force Ground Rules
- Task Force Framing Document
- Consultant Scope of Work
- Meeting Agendas
- Meeting Minutes
- Consultant PowerPoint Presentations