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EXECUTIVE OFFICE OF
ENERGY AND ENVIRONMENTAL AFFAIRS

DEPARTMENT OF ENERGY RESOURCES

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October 11, 2016

Dear Solar Stakeholders:

In February 2016, the Department of Energy Resources (DOER) issued an RFQ that sought consulting services to produce a report to analyze solar program alternatives. After receiving multiple bids, DOER selected Sustainable Energy Advantage, LLC (SEA) of Framingham, MA to perform this analysis. The resulting report helped inform DOER's decisions regarding the design of its proposed solar incentive program and consists of two components:

1. Evaluation of Current Solar Costs, Revenue Requirements, and Needed Incentive Levels
2. Comparative Evaluation of Program Alternatives

In DOER's RFQ and initial conversations with SEA, DOER outlined the following three program design options to be modeled in the report:

1. Declining block tariff
2. Competitive bid/standard offer
3. SREC III

DOER also developed the list of project types for which the consultants were to calculate revenue requirements. Following the establishment of these parameters, SEA identified the underlying cost and financing assumptions that would feed into the larger analysis by conducting a stakeholder survey, which was sent to over 100 companies doing business in the Massachusetts solar market. Results of the survey and outside research were used to inform inputs into the model of required revenues and a separate model used to compute the net aggregate direct ratepayer impacts.

After finalizing the cost and financing assumptions, the consultant team used all of the information available to them to calculate the specific revenue requirements. This analysis allowed DOER to easily compare the expected amount of revenue/incentive that would be required for a particular project under each scenario. It also allowed the consultants to complete their final task, which was to compare the total ratepayer costs under each scenario modeled. To accomplish this, the consultants estimated breakdown and buildout rate of all project types under each program design under consideration. When coupled with the revenue requirement analysis, the consultants were able to determine and compare the total cost of supporting an additional 1,600 MW under each incentive program type.

The results of the consultant analysis indicated that implementing a declining block tariff would be the lowest cost option of the three alternatives identified by DOER. The proposed tariff values in DOER's straw proposal were derived from the revenue requirements that were modeled by SEA for the declining block tariff scenario.

Sincerely,

Judith Judson
Commissioner
Department of Energy Resources

Developing a Post-1,600 MW Solar Incentive Program: Evaluating Needed Incentive Levels and Potential Policy Alternatives

Prepared for the

Massachusetts Department of Energy Resources

By

Sustainable Energy Advantage, LLC

October 11, 2016

About the Massachusetts Department of Energy Resources (DOER)

The Massachusetts Department of Energy Resources (DOER) develops and implements policies and programs aimed at ensuring the adequacy, security, diversity, and cost-effectiveness of the Commonwealth's energy supply to create a clean, affordable and resilient energy future. To that end, DOER strives to:

- Ensure deployment of all cost-effective energy efficiency;
- Maximize development of clean energy resources;
- Create and implement energy strategies to assure reliable supplies and improve the cost of clean energy relative to fossil-fuel based generation; and
- Support Massachusetts' clean energy companies and spur Massachusetts' clean energy employment.

DOER is an agency of the Executive Office of Energy and Environmental Affairs (EEA).

About this Report

In response to RFQ-ENE-2016-010. Sustainable Energy Advantage, LLC (SEA) has developed this report to identify the current costs of different types of solar photovoltaic (PV) installations in Massachusetts, estimate the expected revenue requirement for these installations under different policy, market and finance futures, and to analyze the net present value of the cost to ratepayers of the Commonwealth of different potential solar incentive policy frameworks for deploying an additional 1,600 MW of solar PV beyond the total capacity ultimately installed under the existing Solar Carve-Out and Solar Carve-Out II programs.

The two formal tasks this report and related technical appendices fulfill include:

- *Task 1 - Evaluation of Current Solar Costs and Needed Incentive Levels across Sectors*
- *Task 2 - Comparative Evaluation of Policy Alternatives*

Acknowledgements

SEA and DOER offer their thanks to the wide variety of companies and market participants in the Massachusetts solar industry who answered the survey developed under Task 1 of this analysis, as well as to MJ Shiao of GTM Research for his assistance in selecting a timely and appropriate GTM Research report for understanding the future trajectory of PV balance-of-system costs.

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Table of Contents

Executive Summary

Introduction & Overview

The Massachusetts Department of Energy Resources (DOER) commissioned Sustainable Energy Advantage, LLC (SEA) to analyze alternatives for a successor program to the RPS Solar Carve-Out II (SREC-II) program to support continued development of new solar photovoltaic (PV) installations across the Commonwealth. This analysis compares alternative future solar PV incentive structures solely on the metric of direct ratepayer costs. While PV systems provide many ancillary benefits (which is implicitly why the Commonwealth has provided incentives for PV installations), these benefits – except those that impact direct ratepayer costs – are expected to be similar across alternatives, and the calculation thereof is beyond the scope of this study.

The analysis is comprised of two tasks:

1. Evaluation of Current Solar Costs (and Cost Trajectories), Revenue Requirements and Needed Incentive Levels across Sectors, and
2. Comparative Evaluation of Policy Alternatives. The three different policy alternatives[1] analyzed were:
   a. A "business-as-usual" SREC-III, modeled as a continuation of the SREC-II program with similar structural characteristics other than lower Alternative Compliance Payments and clearinghouse auction price floors (referred to as "SREC-III BAU");
   b. A hybrid program providing for a long-term, bundled fixed-price contract or tariff priced as a standard offer for projects under 250 kW and determined by competitive bidding for larger projects (referred to as "Hybrid CB/SO"); and,
   c. A declining-block incentive, structured as a long-term, bundled fixed-price contract or tariff, with pricing available to installations in each block declining as the market reaches increasing deployment levels (referred to as "Declining Block Incentive" or DBI).

Figure EX- 1 is a schematic overview of SEA's quantitative analysis of Task 1 and Task 2 solar project and ratepayer costs. For Task 1, data for evaluation of current and future PV development costs were compiled from a variety of sources. The revenue and incentive levels required for a solar PV owner to meet its threshold investment requirements were calculated. For this analysis, SEA employed:

- 34 different project classes (which are folded into Rooftop Solar, Community Shared Solar, Landfill Solar, Brownfield Solar, Affordable Housing Solar, Solar Canopies and Large-Scale Greenfield solar market sectors); and

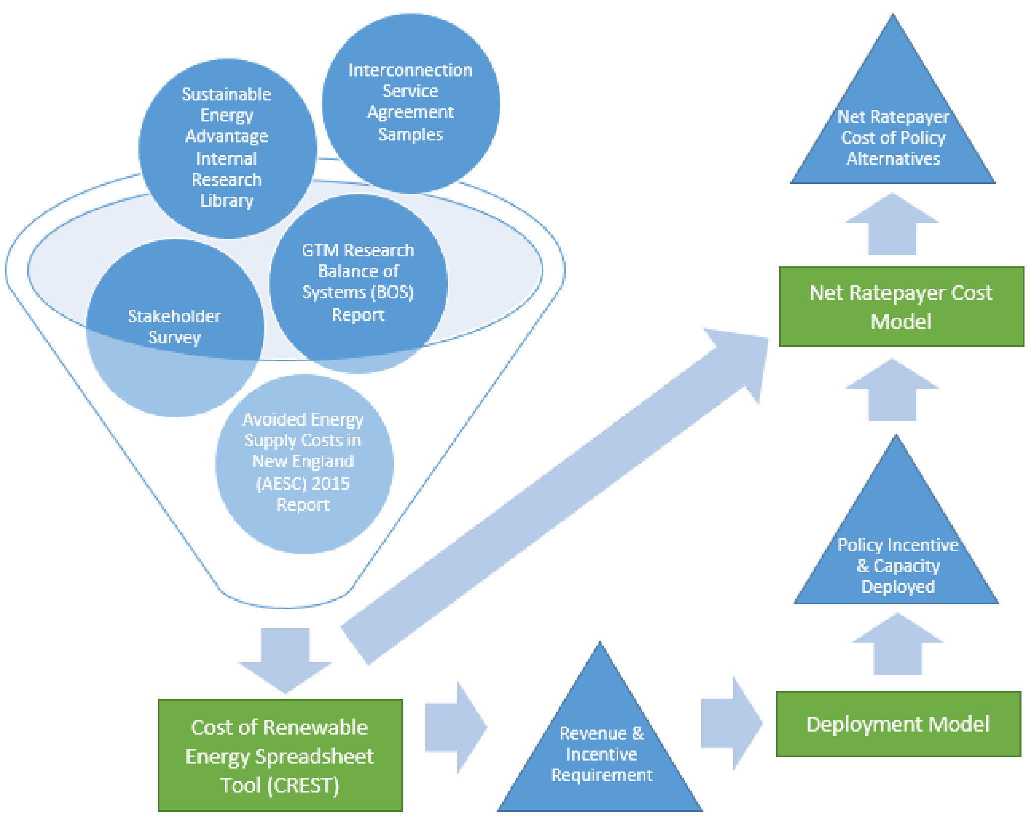
[1] The three distinct policy options assessed were selected for modeling purposes only. They do not necessarily reflect policies under consideration by DOER, but are rather being examined in an attempt to understand and draw distinctions between three general solar policy approaches that have been implemented in Massachusetts and other jurisdictions, while holding most other factors constant. In practice, many specific design parameters may be altered to achieve specific desired results.

- Three different ownership cases (third party, host and public ownership).

The analysis was conducted assuming 1600 MW_{DC} in additional projects were installed over a time horizon spanning the calendar years 2017 through 2022.

Task 2 uses the Task 1 revenue requirements and incentives results and the hypothetical deployment schedule to estimate the aggregate net direct ratepayer costs of each policy alternative. SEA created a deployment schedule based on installation targets constrained by aggregate technical potential and year-over-year growth rates for each of fifteen Competition Groups[2], in order to reflect a policy goal of maintaining project diversity. Project Types are modeled as competing within their Competition Group, with individual Project Types deployed based on cost. Based on projected deployment levels for each Project Type, the next step is to tally the total net incentives paid by ratepayers under each policy alternative.

Figure EX- 1 Schematic of Modeling Flow

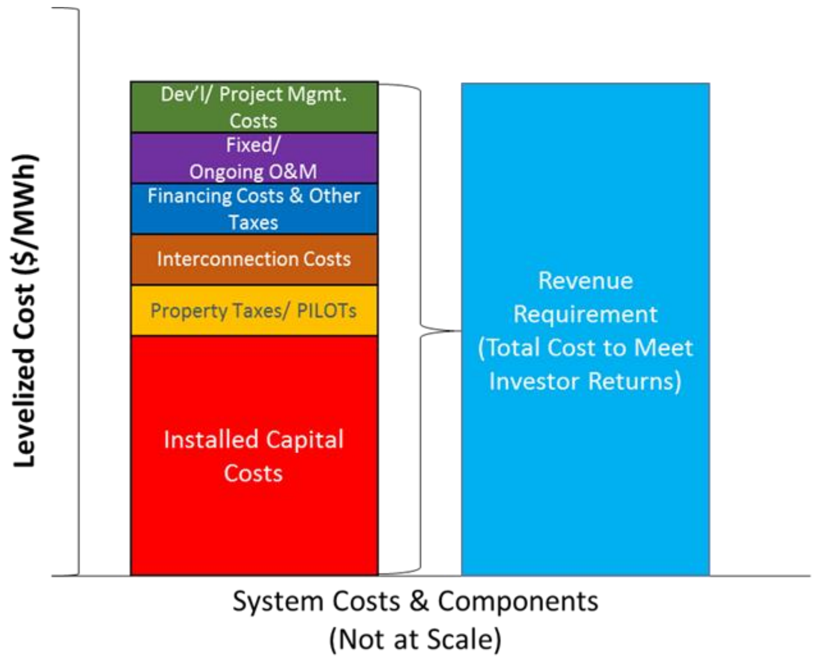


[2] See Table 24 for a complete list of Competition Groups.

Illustration of Task 1 Analysis

The purpose of the Task 1 analysis is to determine both the revenue requirements of the types of projects deployed in Massachusetts, as well as what is their "effective" incentive requirement. The total system revenue requirement is the levelized value of the total upfront and ongoing costs (including O&M and financing costs) needed to deploy the system and meet investor expectations over a 25 year period. While the program incentive needed may be less for systems that consume solar PV energy behind-the-meter (or that continue to receive net metering credits), the "effective" incentive represents the total cost to ratepayers of ensuring each type of system can meet investor returns[3]. Figure EX- 2 and Figure EX- 3 illustrate the two key objectives of the Task 1 analysis.

Figure EX- 2 – Illustration of Revenue Requirement Components



[3] Note if a project has a $250/MWh revenue requirement, but has access to net metering that provides a value above wholesale rates of $150/MWh, the actual incentive it needs to meet its revenue requirement from the policy alternative only be $100/MWh.

Figure EX- 3 – Illustration of Calculation of "Effective Incentive" Requirement Borne by Ratepayers

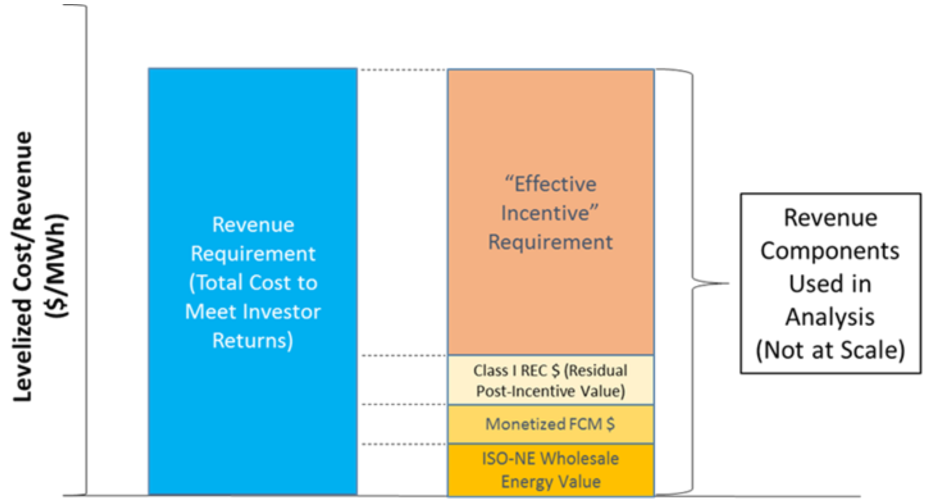
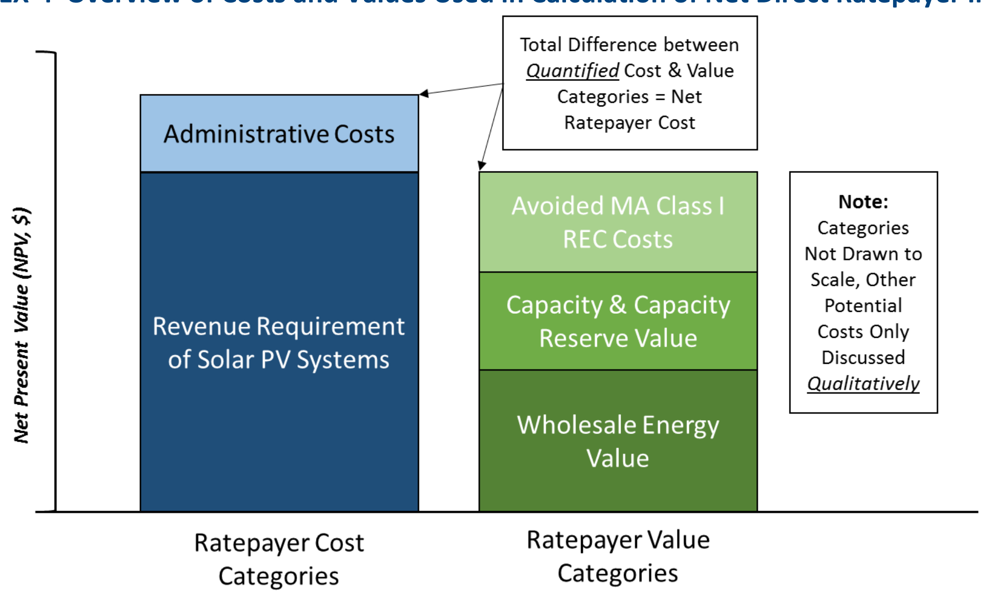


Illustration of Task 2 Analysis

The components of net direct ratepayer impacts are displayed in Figure EX-4. On the cost side, administrative costs, which vary by policy alternative, are added to the policy alternative revenue requirements. These value of solar PV production includes the value of commodity electricity production (wholesale energy market value and costs associated with capacity obligations), as well as the avoided purchase of Class I REC purchases that would otherwise be required. The net ratepayer cost of each policy alternative to ratepayers can be estimated by subtracting these values from total costs associated with each alternative.

Figure EX-4 Overview of Costs and Values Used in Calculation of Net Direct Ratepayer Impacts



Policy transition costs (discussed in Section 5.1) are acknowledged to exist, and are assumed to be incurred by moving away from an SREC structure, but are not explicitly quantified.

Key Disclaimers for This Analysis

The three distinct policy options assessed were selected for modeling purposes only, and do not necessarily reflect policies under consideration by DOER, but are rather being examined in an attempt to understand and draw distinctions between three general solar policy approaches that have been implemented in Massachusetts and other jurisdictions, while holding most other factors constant. In addition, the purpose of this analysis is to evaluate the relative net present value (NPV) of the net direct cost to ratepayers of each of the policy alternatives under discussion so as to aid DOER in understanding the relative costs to ratepayers of varying incentive programs. **As a result, this analysis is not intended as a 'value of solar analysis' for Massachusetts, nor as a cost-benefit analysis incorporating the direct and indirect costs and benefits of solar PV or net metering in Massachusetts.**

Stakeholder Survey

In order to elicit the detailed information on various factors that affect PV project development and the successor for the SREC-II program, SEA conducted a two-part stakeholder survey. Results of the surveys and research were used to inform inputs into the model of required incentives (e.g., project costs and financing assumptions), deployment model (e.g., technical potential constraints on installed capacity, the financing of SREC revenue), and a separate model used to compute the net aggregate direct ratepayer impacts (which include administrative costs).

Key Assumptions

In order to estimate current and future incentive levels required to facilitate PV development, a suite of assumptions must be made. Key policy and market assumptions are as follows:

- The successor program is assumed to commence starting January 1, 2017 and have 1600 MW_{DC} of projects installed by December 31, 2022 or 267 MW_{DC} for each of six calendar years. The program incentives are assumed to last 10 or 20 years depending upon the case modeled.
    - The Competition Group mix was held constant across policy alternatives for modeling and is an approximation of the SREC-II market share taking into technical potential limits that constrain the unfettered groups for some type of projects (e.g., landfills, virtually net metered affordable housing).
    - At the technology level, all systems were assumed to be fixed-tilt, have appropriate capacity factors for the project type and location, have a 25 year system life and be subject to 0.5% annual production degradation.
- Year 2016 project costs including financing costs (which vary by policy alternative) were estimated as an amalgamation of custom research and publicly available reports. Future cost trajectories were based on SEA's hybrid GTM Research and NREL forecast of a compound annual nominal decline rate between 2014 and 2025 of 8.1% for all residential-scale base cost cases, 9.6% for commercial-scale systems and 9.1% for utility-scale.

- In general, the analysis framework is consistent with recently enacted Chapter 75 of the Acts of 2016, with the following exceptions. For modeling purposes, we have assumed that net metering will be available to *all* projects, but that new projects under a successor program will be compensated at the wholesale energy rate. This simplification avoided clouding the determination of incremental ratepayer cost with hidden net metering transfers among incentive participants and non-participants.
- Under current rules behind-the-meter (BTM) projects would reap full avoided retail rates, and the majority of projects equal to or less than 25 kW_{AC} also would continue to receive current Class I net metering credits (which include the EDC's default generation service, transmission, transition and distribution rate components). Nonetheless, in order to create a straight-forward apples-to-apples comparison of Policy Alternatives for this analysis, the incentive requirement value SEA calculates is the "effective" incentive borne by ratepayers for the program. This effective incentive is equal to the total revenue requirement less the wholesale energy, any monetized capacity value[4] and a residual pro forma value for MA Class I RECs. The effective incentive is, thus, inclusive of net metering credit value and the avoided value of retail charges for BTM projects. This means the effective incentive does not necessarily represent at what level the incentive from a Policy Alternative would need to be set at (e.g., SREC level or tariff rates) because part of incentive requirement could come from net metering credits or avoided retail rates. Note the difference in value of MA Class I RECs varies by whether the RECs are generated during the program incentive period or after the program incentive period.
    - The MA Class I REC value included in the Task 1 modeling is assumed to be $5/MWh after a 10- or 20-year incentive expires, so as to conservatively account for a *financier's* perspective regarding the uncertainty of financing on the basis of future REC streams.
    - For Task 2 we assume the MA Class I REC avoided value to *ratepayers* during the incentive period is assumed to be used in the 'expected' value of the avoided Class I purchase– and uses a forecast derived from public sources (see Section 4.1.3.6 for full details).
- Federal incentives remain as currently structured (e.g., the investment tax credit phase down).
- Wholesale energy market value was based on a solar PV production-weighting of hourly energy prices during a base year of 2016. The projected wholesale energy market prices were trended into the future from the base year using the year-over-year trajectory of Massachusetts wholesale energy prices from the Avoided Energy Supply Costs in New England: 2015 Report (Hornby, et al., 2015).
- The calculation of net ratepayer costs assumed a nominal 5% discount rate.

[4] SEA recognizes that in practice, revenue from the Forward Capacity Market could be monetized by all, none, or some projects. However, for simplicity, the analysis assumes none of the projects monetize FCM revenue. While this likely overstates the absolute scale of the incentive, it facilitates the apples-to-apples comparison of policy alternatives.

Task 1 Results

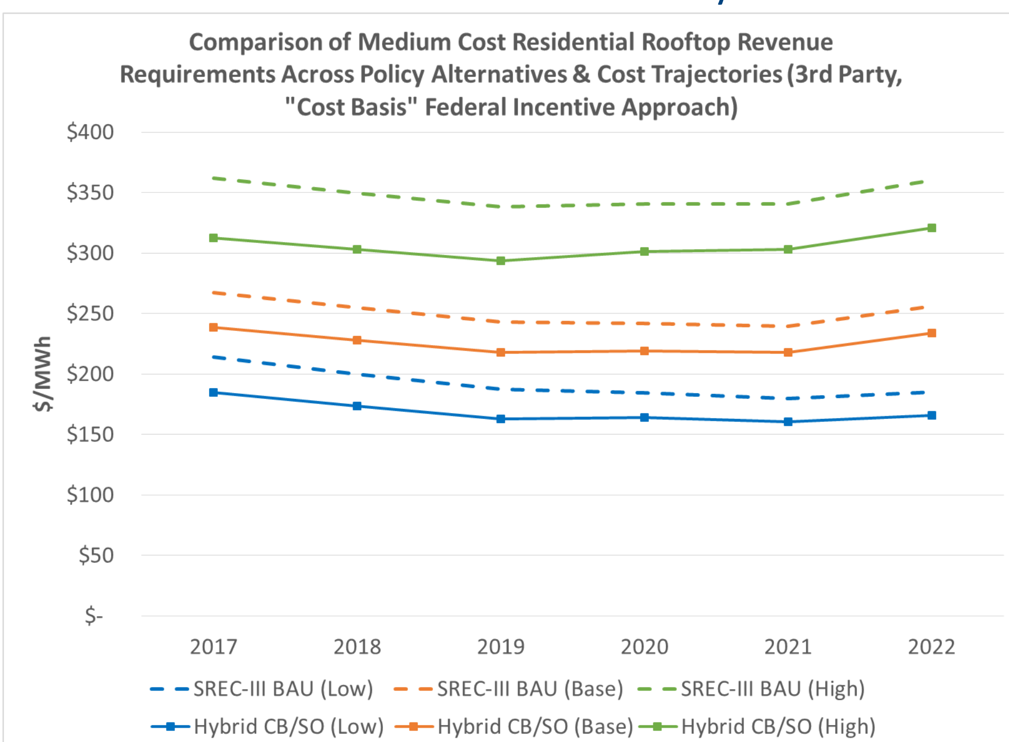
Solar PV System Cost Analysis Results & Key Drivers

Driver 1: Differences in Policy Alternatives

The relative reduction in the cost of capital associated with the “bundled” non-SREC alternative programs plays a significant role in terms of system costs and revenue requirements (and, as discussed below, the overall cost of each policy alternative to ratepayers). Relative to an SREC structure which exposes system owners to uncertain SREC and commodity revenue streams, Figure EX- 5 shows how the reduction in the cost of capital associated with the greater revenue hedging to system owners of “bundled” non-SREC alternative programs manifest themselves in terms of the average revenue requirement for an illustrative medium cost residential roof mount systems.

Under an SREC-III future, the overall revenue requirement is significantly higher than for the same system under both non-SREC “bundled” Hybrid Competitive Bid/Standard Offer and Declining Block Incentive options. Furthermore, while it is possible to discern significant cost reductions from 2017 and 2020 in both cases, the overall levelized revenue requirement remains flat) or goes up slightly relative to 2020 values, which can be traced to federal incentives being reduced (or expiring) under current law.

Figure EX- 5: Comparing Revenue Requirements for Medium Cost Residential Roof Mount under SREC-III BAU and Bundled Purchase Policy Alternatives



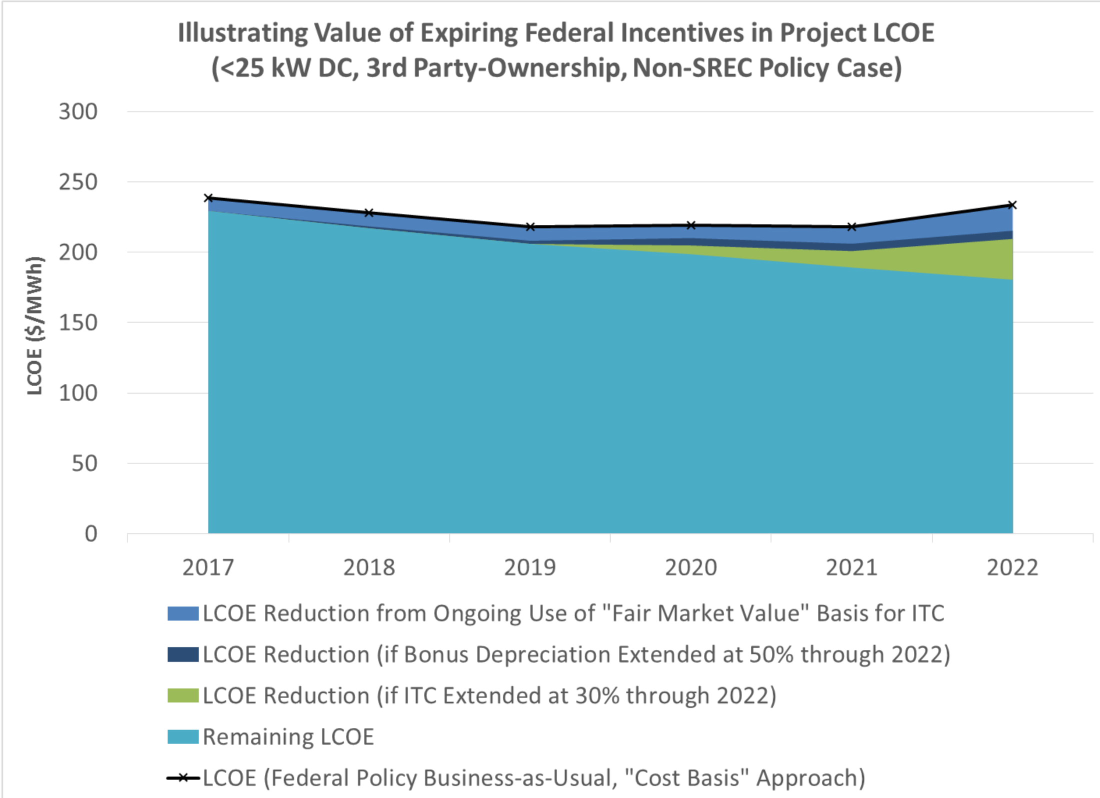
Driver 2: Federal Policy

In this analysis, levelized revenue requirements that track with total system costs have a less dramatic decline than the underlying decline in system installed costs. While due in part to increasing costs of interconnection and O&M, the most significant contributor to this relative result is the phase-down (under current law) of the ITC in 2022 and bonus depreciation in 2020. Furthermore, the manner in which developers choose to monetize available federal tax benefits plays a key role in determining the relative competitiveness of host- and third party-owned systems. While all third-party and host-owned system equity investors can choose to utilize the federal tax benefits described above on the basis of the system's underlying cost (referred to herein as the "cost basis" approach), third-party system owners can choose under current tax law to monetize their tax benefits based on the system's "fair market value".[5]

Figure EX-6 shows that the impact of the expiration of these federal incentives largely explains the overall difference between levelized cost of energy (LCOE) and installed capital cost trajectories. While a full extension of all expiring federal incentives (and retention of the "fair market value" approach) would allow revenue requirements to fall 18%, allowing the ITC and bonus depreciation to expire under current law (and assuming "fair market value" is not a viable future option for third party developers) results in only a 2% overall reduction between 2017 and 2022, with costs increasing between 2020 and 2022.

[5] When third-party developers choose the "fair market value" approach, they are able to claim the ITC on a basis that exceeds the system's installed cost. To date, this has been a common approach for some installers choosing to do business in Massachusetts, but not others. However, the approach has been the subject of enhanced scrutiny by the Treasury Department's Inspector General for Tax Administration since 2012, which has not (to date) concluded its investigation (Bolinger & Holt, 2015). For the purposes of this analysis, SEA has conducted Task 1 and Task 2 sensitivities that account for these differences, in which it is assumed that either 1) all third party and host-owned projects monetizing the ITC use the "cost basis" approach or 2) that all third-party owned projects monetize the ITC using the "fair market value" approach, while host-owned projects do not.

Figure EX-6 - Levelized Cost Value of Expiring (or Potentially Expiring) Federal Incentives for Year Shown (Medium Cost <25 kW DC Systems under a Base Cost Trajectory, 3rd Party)



Driver 3: System Size Differences

Larger-scale solar PV systems tend to enjoy economies of scale in terms of their unit costs. In Table EX-1 and Table EX- 2, SEA compares the average revenue requirement of medium-cost small commercial and residential roof-mounted systems with the average requirement for a medium-scale building-mounted system (both of which use the "cost basis" approach for valuing federal incentives).

Table EX- 1 - Average Revenue Requirement in Year Shown of Medium Cost Residential/Small Commercial Rooftop Systems under Low, Base and High Cost Trajectories (Third Party-Owned)

Medium Cost Rooftop Solar (<=25 kW) (SREC-III BAU 10-Year, Third Party-Owned, Cost Basis, $/MWh)						
Installed Capital Cost Trajectory	2017	2018	2019	2020	2021	2022
Low	$214	$200	$187	$184	$180	$185
Base	$268	$255	$243	$242	$239	$256
High	$362	$350	$338	$340	$341	$360

Table EX- 2 - Average Revenue Requirement for Year Shown of Medium Building Mounted (500 kW DC) Rooftop Systems under Low, Base and High Cost Trajectories (Third Party-Owned)

Rooftop Solar (500 kW) (SREC-III BAU 10-Year, Third Party-Owned, Cost Basis, $/MWh)						
Installed Capital Cost Trajectory	2017	2018	2019	2020	2021	2022
Low	$150	$140	$132	$130	$127	$129
Base	$190	$181	$172	$171	$168	$172

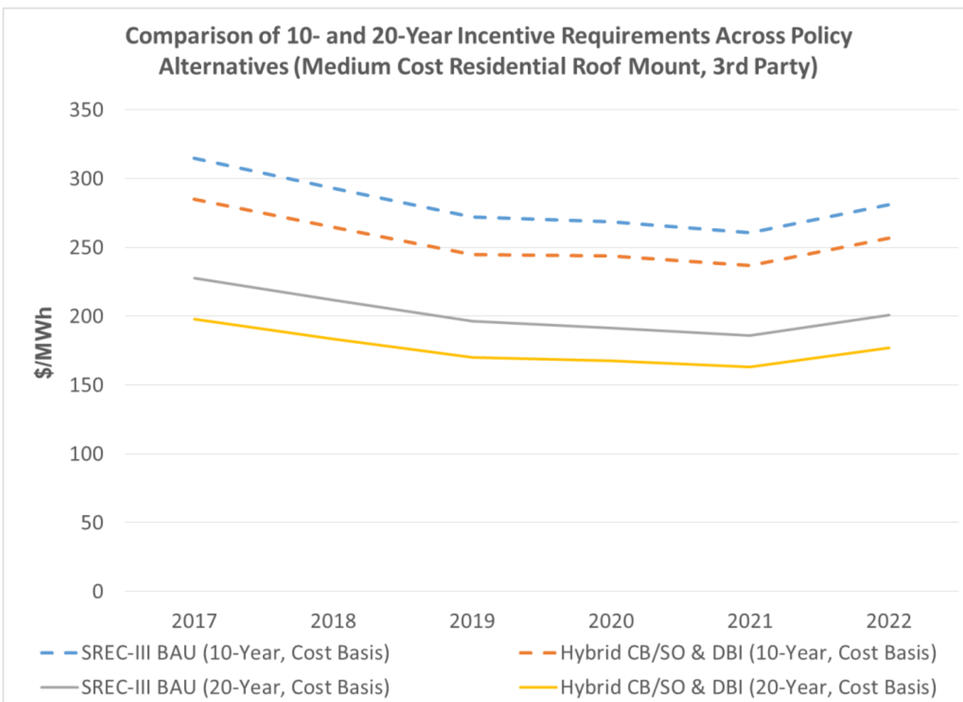
High	$242	$234	$226	$226	$225	$233

As SEA observed for other installation types, overall costs of the 500 kW DC medium commercial building-mounted system under different installed capital cost trajectories are decidedly smaller than for a medium-cost residential/small commercial system (<= 25 kW DC).

Driver 4: Duration of Incentives

The choice of incentive duration has a significant impact on the levelized unit values of incentives offered to solar generators. Some stakeholders have advocated for one policy future over another based on comparisons of per-MWh inventive levels among policies of different durations, which can be quite misleading. Figure EX-7 shows the differences in incentive requirements for the same residential roof mounted third-party owned system under 10- and 20-year incentive durations. As the graph shows, if DOER were to elect a 20-year incentive framework over a 10-year framework, the per-unit value of the levelized incentive paid to generators would be significantly lower.

Figure EX-7 – Comparing 10- and 20-Year "Effective" Incentive Requirements for Residential Roof Mounted Systems across Policy Alternatives

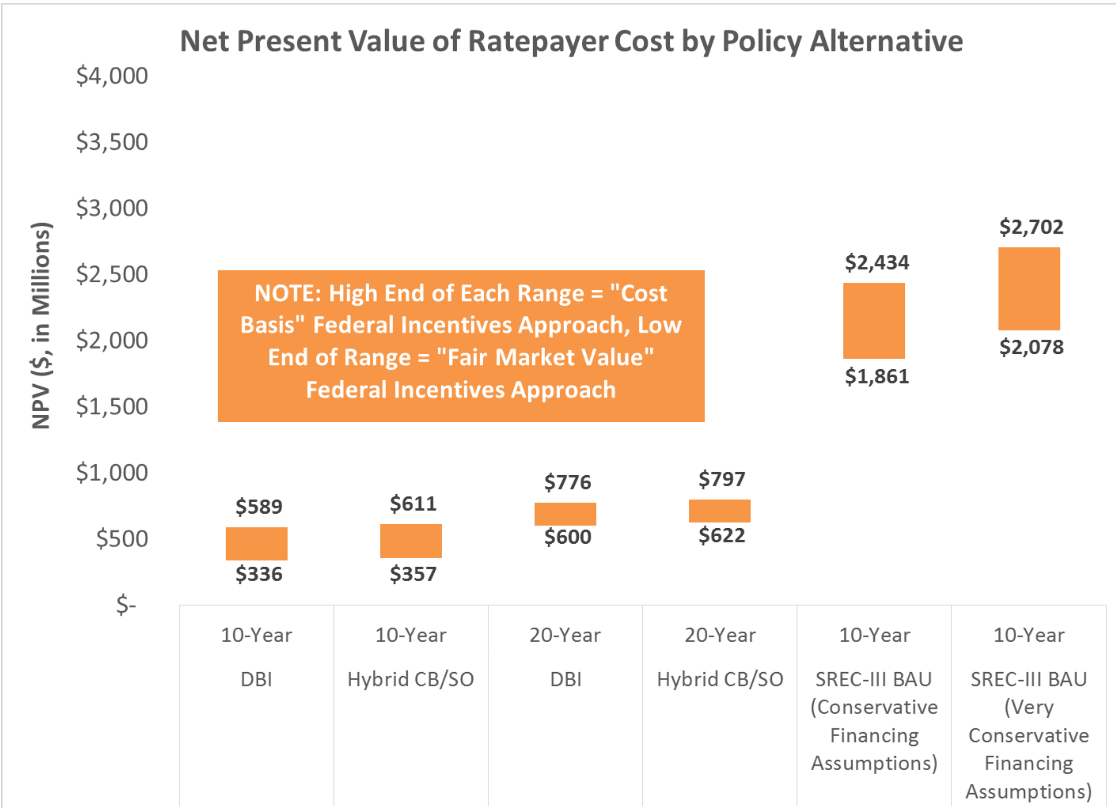


Task 2 Results – Net Ratepayer Cost of Policy Alternatives

Range of Results

As shown in Figure EX-8, a SREC-III alternative as configured and modeled is expected to be materially more costly to ratepayers than either of the bundled policy alternatives (DBI or Hybrid CB/SO). SEA finds that the cost to ratepayers of each of the three policy alternatives considered in this analysis, as measured by net present value (NPV) of cost to ratepayers, varies significantly depending on whether project developers take depreciation and the ITC on the basis of the system's cost, or its "fair market value" (as defined by Internal Revenue Service (IRS) regulations.

Figure EX-8: Range of NPVs by Policy Alternative and Treatment of Federal Incentives



Components of Net Direct Ratepayer Impacts

Overall, the SREC-III BAU alternatives represent a higher cost to ratepayers largely due to the fact that developers seeking financing under SREC-III cases are expected to need a higher cost of capital to meet debt and equity investor expectations than the bundled Hybrid CB/SO and DBI policy alternatives. Thus, under the SREC-III cases, the cost of revenue requirements to ratepayers is elevated relative to the non-SREC cases. Table EX- 3 and Table EX- 4 below illustrate each component of the net direct cost to ratepayers for each policy alternative, deployment scenario and SREC-III BAU 10-year market expectation case.

Table EX- 3 - NPV of Net Direct Ratepayer Costs by Component under "Cost Basis" Approach (NPV in 2016$, Millions)

Policy Alternative	DBI (10-Yr)	Hybrid CB/SO (10-Yr)	DBI (20-Yr)	Hybrid CB/SO (20-Yr)	SREC-III BAU (Conservative Financing Assumptions) (10-Yr)	SREC-III BAU (Very Conservative Financing Assumptions) (10-Yr)

Cost Case	Base	Base	Base	Base	Base	Base
Incentive Duration	10-Year	10-Year	20-Year	20-Year	10-Year	10-Year
Revenue Requirements	$4,633	$4,633	$4,820	$4,820	$6,567	$6,835
Administrative Costs	$91	$113	$91	$113	$0	$0
Direct Ratepayer Costs	**$4,724**	**$4,746**	**$4,911**	**$4,932**	**$6,567**	**$6,835**
Generation Capacity & Capacity Reserve Value	$738	$738	$738	$738	$738	$738
Wholesale Energy Value	$2,423	$2,423	$2,423	$2,423	$2,422	$2,422
Avoided Class I REC Costs	$974	$974	$974	$974	$974	$974
Offsetting Ratepayer Value	**$4,135**	**$4,135**	**$4,135**	**$4,135**	**$4,133**	**$4,133**
Net Direct Ratepayer Costs	***$589***	***$611***	***$776***	***$797***	***$2,434***	***$2,702***

Table EX- 4 - NPV of Net Direct Ratepayer Costs by Component under "Fair Market Value" Approach (NPV in 2016$, Millions)

Policy Alternative	**DBI (10-Yr)**	**Hybrid CB/SO (10-Yr)**	**DBI (20-Yr)**	**Hybrid CB/SO (20-Yr)**	**SREC-III BAU (Conservative Financing Assumptions) (10-Yr)**	**SREC-III BAU (Very Conservative Financing Assumptions) (10-Yr)**
Cost Case	Base	Base	Base	Base	Base	Base
Incentive Duration	10-Year	10-Year	20-Year	20-Year	10-Year	10-Year
Revenue Requirements	$4,379	$4,379	$4,642	$4,642	$5,995	$6,211
Administrative Costs	$91	$113	$91	$113	$0	$0
Direct Ratepayer Costs	**$4,470**	**$4,491**	**$4,734**	**$4,755**	**$5,995**	**$6,211**
Wholesale Energy Value	$738	$738	$738	$738	$738	$738
Generation Capacity & Capacity Reserve Value	$2,422	$2,422	$2,422	$2,422	$2,422	$2,422
Avoided Class I REC Costs	$974	$974	$974	$974	$974	$974
Offsetting Ratepayer Value	**$4,134**	**$4,134**	**$4,133**	**$4,133**	**$4,133**	**$4,133**
Net Direct Ratepayer Costs	**$336**	**$357**	**$600**	**$622**	**$1,861**	**$2,078**

Under an SREC-III future, assumptions on future SREC prices have to be made for financing. SREC prices (by design, and based on past experience with the model) tend to be binary, either near the ACP (price cap) in times of shortage or near the auction floor in times of surplus. A debt financier (such as a bank or other lender) is likely to assume cash flow to a project associated with a future that might be characterized as a number of years near either the cap or near the floor. Overall, SEA assumed that these financers tend to be conservative. Thus, the SREC-III "Conservative" case corresponds to a case in which financiers assume for their pro-forma purposes an SREC cash flow equivalent to SREC prices being near the floor for 7 years and near the ACP for 3 years, while the "Very Conservative" case assumes cash flow likely be exceeded with 90% probability (often referred to as a "P90" case, with prices at the soft price floor for all 10 years.[6] SEA assumes that higher levels of financier conservatism translate to less debt leverage (resulting in a higher overall cost of capital), and thus direct costs to ratepayers. Some totals in both tables may not be exactly equal (even with similar incentive durations), given that within each scenario, the quantities of each Project Type assumed deployed can differ slightly from one another. Thus, there is an inverse relationship between the amount of debt used to finance the project and the number of years prices are assumed to be at the floor. However, SEA believes it is possible that as lenders become more comfortable with the policy, they would be more likely to lend against the SREC revenue stream, and thus assume more years at the ACP.

Ratepayer Cost Differences between 10-Year and 20-Year Incentives

Superficially, it might appear, given that 10-year incentives require higher unit costs per megawatt-hour of solar production than a 20-year program, that the latter type of program would be less expensive for ratepayers. However, this is not the case. Even though the unit cost of "effective incentives" under a 20-year program is much lower than under a 10-year program, the cost to ratepayers of 10-year programs is significantly lower than under a 20-year program for two reasons:

- The total incentive needed beyond ISO-NE wholesale rates does not drop by half after incentive durations are doubled, and
- While the required return to finance a project varies by policy alternative, an investor's required return is always significantly higher than the 5% discount rate assumed for ratepayers. Thus, a longer incentive duration will result in the financing costs compounding, and exceeding the assumed ratepayer discount rate, over 20 rather than 10 years.

SREC-III BAU (10-Year) Financing Sensitivity

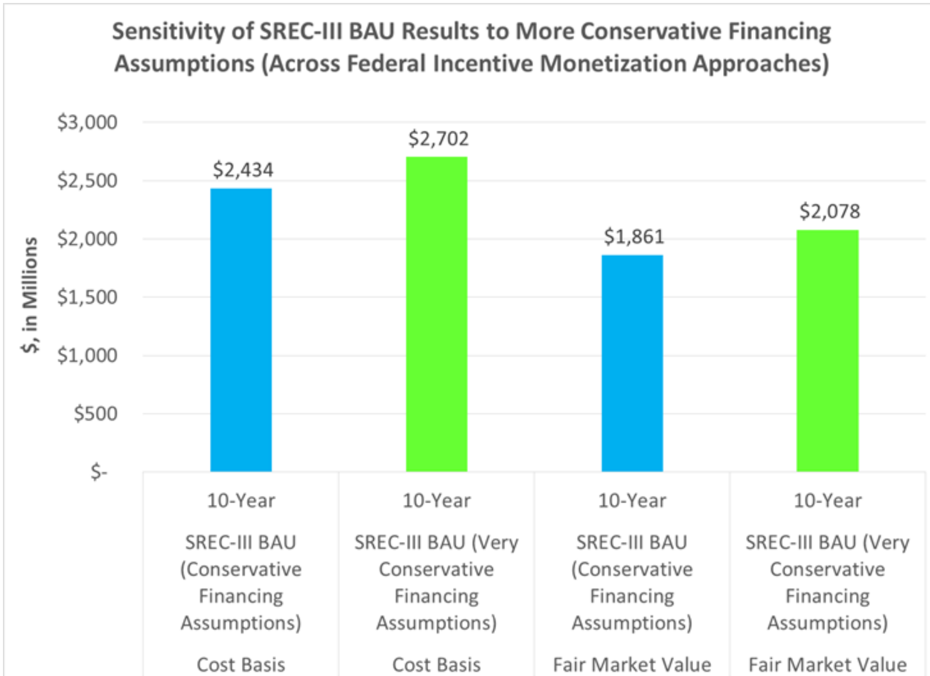
In order to better understand how investors might react to a perceived SREC-III market (as an extension of SREC-II), SEA undertook a sensitivity in which an investor assumes that a project will not receive any revenue beyond the auction floor for all 10 years the project is eligible for SREC-based incentives. In such a scenario, the investor would effectively finance less of the project at normal rates, or would increase their required return, thus increasing the need for incentives for the system to deploy.

Figure EX- 9 below illustrates the results of this sensitivity analysis as compared with a scenario in which a financier assumes a minimum of 3 years of SREC revenue at the ACP, under both the "cost basis" and "fair market value" approaches to monetizing federal tax incentives. While the change results in a $200-$300 million net increase in ratepayer cost, these findings suggest that the investor's risk perception does not significantly alter the relationship of the SREC-III BAU policy alternative to the other bundled-

[6] Based on SEA's analysis of the SREC markets (Grace, et al., 2015), over-the-counter market SREC hedges (i.e. long-term rather than spot SREC sales) have tended to trade at a discount to expected long-term cash flows, which would produce revenues to project owners which might have a similar ultimate impact on required incentive. In other words, generators sell their SRECs to risk-taking market participants at a discount and those risk-taking market participants seek to take advantage of a significant arbitrage opportunity by selling the SRECs to compliance buyers at a profit. Ultimately, ratepayers paying for compliance absorb costs at the higher rate at which compliance entities purchase the SRECs. See Figure 41 of Task 3 Report of Net Metering and Solar Task Force for an illustration (Grace, et al., 2015).

purchase alternatives (Hybrid CB/SO and DBI). Indeed, SEA believes it would be unreasonable for an investor to assume a market sufficiently in shortage that market prices would be at the ACP for more than 5 years of the ten-year incentive duration for any given project built between 2017 and 2022.

Figure EX- 9 – Comparison of SREC-III BAU Results (Assuming More Conservative Financing Assumptions)



Limitations of Analysis and Potential Areas for Further Analysis

Modeling the Impact of Market Forces

An overarching objective of this analysis is to make as close to an "apples-to-apples" comparison on a net ratepayer cost basis between the three policy alternatives under consideration. After considering various ways to do so, SEA and DOER jointly determined that the simplest approach to do so was to develop a uniform PV deployment scenario across all policy alternatives. However, this means that SEA did not ultimately apply the type of dynamic supply/demand models it typically uses for forecasting deployment and incentive levels in REC-based markets, as such modeling was outside of the scope. Instead, for the purposes of this analysis (and regardless of the policy alternative under consideration) SEA assumed that incentives should be set to induce a sufficient volume of deployment from each Competition Group given the "Modified Market Share" deployment case. Thus, SEA was unable to determine exactly what systems would economically "clear" (and be built) if the SREC-II ACP and auction floor values were extended into the future under an SREC-III BAU program at the same rates of decline currently expected for the SREC-II program.

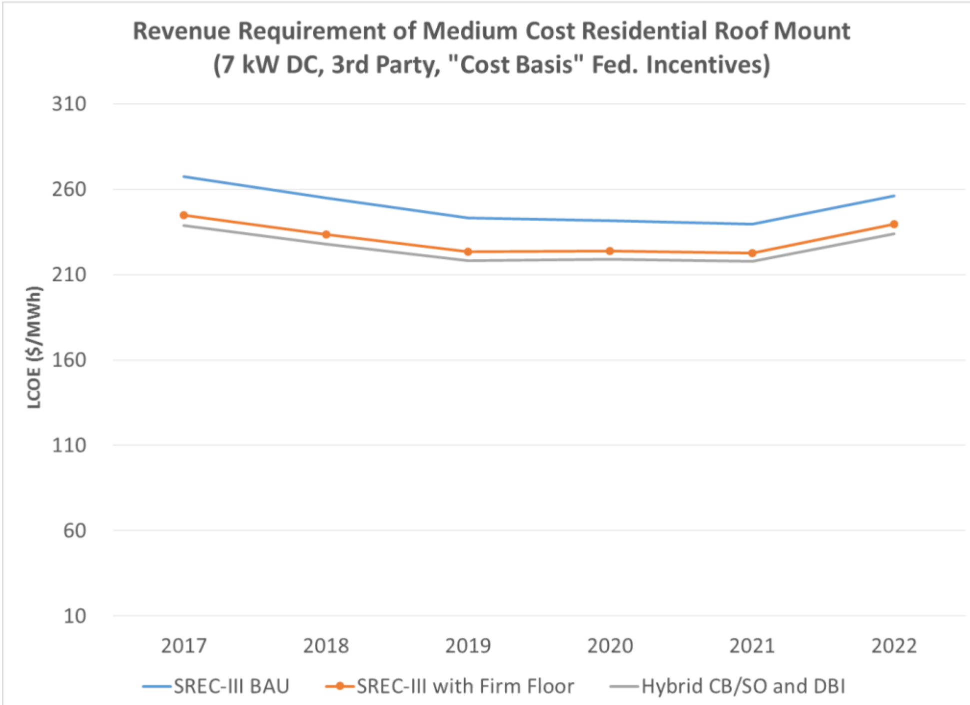
The question of which policy would produce a lower total cost for ratepayers can only be fully investigated with modeling of competitive economic dynamics of the Massachusetts solar market, thus relaxing the modeling constraints of uniform deployment across policy alternatives and of using 15 separate Competition Groups necessary to preserve market diversity. While outside of this report's scope, employing more robust market models would allow for a more robust forecast of the cost impact for all three policy scenarios that reflects conditions and constraints present in a more realistically dynamic market - in which a wider array of market forces better determine deployment and relative market share among installation types.

Firming an SREC-III Auction Floor

By manipulating various design details, the differences between policy futures can be reduced. One key limitation of this analysis is the absence of considerations which could be employed to maintain an SREC market structure while lowering its cost to ratepayers. A prime example is firming the SREC-III BAU's price floor. While the current SREC-II structure utilizes a "soft" auction floor, it is possible to design a program with a guaranteed minimum price (similar in design to the firm price cap created by an ACP). This approach could be further engineered by adding SREC factors to account for cost and site suitability, as utilized in SREC-II.

To illustrate to potential impact of firming the price floor (for example, by creating a buyer of last resort at the floor price). Figure EX- 10 shows the relative revenue requirement in an SREC-III case with a firmed auction floor at current levels (as discussed in the SREC-III assumptions section above). As can be seen in Figure EX- 10, a firm price floor can be accompanied by a lower ACP in a manner that brings the SREC revenue requirement very close to the Hybrid CB/SO and DBI revenue requirements.

Figure EX- 10 – Potential Revenue Requirement Comparison of SREC-III Firm Floor with Other Policy Alternatives (Using Medium Cost Residential Roof Mount)



While outside the scope of this report, full analysis of a modified SREC design with a firm price floor may reveal additional insight as to whether such an SREC approach could yield sufficiently similar ratepayer cost results as the other models, while avoiding both the increases in administrative costs quantified herein, and the unquantified policy transition costs that would be borne by market participants (developers, financiers, brokers/market makers, etc.) in moving away from an SREC approach.

Alternative Deployment Cases (e.g., Front-Loading or Back-Loading of Program Targets)

As SEA and its fellow analytical team members described in the *New York Solar Study*, program cost control can be accomplished with both volume- and price-based limitations (New York State Research and Development Administration, 2012). The Hybrid CB/SO and DBI policy alternatives modeled in this analysis assume equal deployment levels in each year.

However, it may be possible to enhance the level of ratepayer cost control built into each policy design (for example) by back-loading the total capacity procured or contained within the defined capacity blocks of the DBI policy alternative. The potential ratepayer benefit of such an approach may derive from the strong probability of total PV system cost reductions under both base and low installed capital cost trajectories. However, such an approach may carry risk, especially if system costs follow a higher installed capital cost trajectory than is generally expected, given that back-loading would be of less significant benefit for ratepayers, and would slow down market development in prior years relative to a uniform annual deployment trend. Analysis of alternative deployment trajectories could yield additional insight into policy design approaches that balance industry development with ratepayer cost.

Impact of Potential Utility-Scale Construction Lag on Federal Investment Tax Credit (ITC) Utilization

A key change to the ITC included in the legislation extending and stepping down the credit (Consolidated Appropriations Act, 2016 (H.R.2029), 2015) alters the basis for claiming the applicable credit from being "placed in service" to "property (under) construction", so long as the property under construction reaches commercial operation before January 1, 2024. While the IRS (Internal Revenue Service, 2016) allowed for as long as 4 years to pass between qualifying for under construction or equivalent safe harbor, and commercial operation, we assume that solar projects are more likely to take up to 2 or 3 years if availing themselves of the safe harbor provisions. Even so, determining appropriate incentives in 2020, 2021 and 2022 resulting from this change could be rather complex, given that larger-scale solar projects commencing construction in those years (or earlier) could claim an ITC value that is significantly higher than the value associated with that year. However, the impact on total cost to ratepayers could be material.

Table EX- 5 Effect of Construction Lag on ITC Usage for Systems Larger than 1 MW (1000 kW) Deployed in 2022 (3rd Party, "Fair Market Value")

Project Type and Modeled Size (kW DC)	LCOE (Systems w/2022 COD, ¢/kWh)			LCOE Range (2020 & 2021 Const. Start, ¢/kWh)	% Difference Range (2020 & 2021 Const. Start)
	10% ITC (2022 Const. Start	22% ITC (2021 Const. Start)	26% ITC (2020 Const. Start)		
Campus Lot Canopy (1000)	16.75	15.27	14.82	1.48-1.93	8.8%-11.5%
Medium Cost Community Shared Solar (1000)	17.62	16.39	16.03	1.22-1.59	6.9%-9.0%
Medium Cost VNM LIH (1000)	15.58	14.37	14.01	1.21-1.58	7.8%-10.1%
Large Building Mounted (1000)	13.66	12.65	12.34	1.01-1.32	7.4%-9.7%
Medium Landfill (1000)	15.96	14.72	14.34	1.24-1.62	7.8%-10.2%
Large Landfill (4000)	13.98	12.76	12.39	1.22-1.59	8.7%-11.4%
Medium Brownfield (1000)	15.39	14.16	13.79	1.23-1.60	8.0%-10.4%
Large Brownfield (4000)	13.19	12.04	11.68	1.16-1.51	8.8%-11.5%
Medium Cost Ground Mount (1000)	13.59	12.55	12.24	1.04-1.36	7.7%-10.0%
Large Ground Mount BTM (2000)	12.73	11.69	11.38	1.03-1.34	8.1%-10.6%
Medium Cost Ground Mount (4000)	12.93	11.87	11.56	1.06-1.37	8.2%-10.6%

In the analysis results presented above, SEA assumed (for simplification purposes) that all projects qualifying in any given year will begin construction and reach commercial operation in that same year, and claim the ITC at the level available for that specific tax year. Thus, the analysis, as currently structured, does not account for tax equity investors claiming credit amounts that exceed the ITC's apparent value in the years in which the systems reach commercial operation. In practice, for example, a project reaching commercial operation on December 31, 2022 could claim the incentive level applicable in 2019 (at the extreme), 2020 or 2021. As such, setting incentives based on these apparent annual values may significantly overstate the required incentive needed to ensure that these systems are properly financed and deployed. As Table EX- 5 shows, the total reduction in revenue requirement for projects 1 MW_{DC} or larger taking between 2 and 3 years could reach nearly 12%. While the year in which the tax credit is taken likely will not be known to DOER in the process of setting incentives for 2022 (or any other year affected by these provisions of the tax law), the totals shown in this report for total ratepayer incentive are likely overstated.

While outside the scope of this report, DOER may find added value in analyzing the impact of these new provisions in the tax law via sensitivity analysis of system and ratepayer cost surrounding assumptions of construction lag for utility-scale projects, and how that construction lag could manifest itself in later years of the program, especially once the IRS issues further guidance on "commenced construction" provisions surrounding the ITC (Internal Revenue Service, 2016). With this information, it is possible for DOER to assess ways in which to set incentives that reflect realistic assumptions regarding the level of ITC being claimed by developers receiving a state incentive. DOER may wish to consider whether incentive levels might be set accounting for projects maximizing their tax benefits as well as potentially less than full monetization of incentives.[7]

[7] SEA notes that tax equity may become increasingly scarce over time, and that therefore assuming full monetization of these tax benefits may potentially not be appropriate.

1 Overview of Post-1600 MW Program Analysis Approach

1.1 Introduction & Overview

The Massachusetts Department of Energy Resources (DOER) commissioned Sustainable Energy Advantage, LLC (SEA) to analyze alternatives for a successor program to the RPS Solar Carve-Out II (SREC-II) program to support continued development of new solar photovoltaic (PV) installations across the Commonwealth.

The study is comprised of two tasks:

Task 1: Evaluation of Current Solar Costs (and Cost Trajectories), Revenue Requirements and Needed Incentive Levels across Sectors, and

Task 2: Comparative Evaluation of Policy Alternatives. The three different policy alternatives[8] analyzed were:

a. A "business-as-usual" SREC-III, modeled as a continuation of the SREC carveout program with similar structural characteristics to SREC-II other than lower Alternative Compliance Payments and clearinghouse auction price floors (referred to as "SREC-III BAU");
b. A hybrid program providing long-term, bundled[9] fixed-price contract or tariff, priced as a 'standard offer' for projects under 250 kW, and with price determined by competitive bidding for larger projects (referred to as "Hybrid CB/SO"); and,
c. A declining-block incentive, structured as a long-term, bundled fixed-price contract or tariff, with standard offer pricing available to installations in each block, with such pricing available in 'blocks' of a specified capacity quantity, and prices available to successive blocks of new installations declining as the market reaches increasing deployment levels (referred to as "Declining Block Incentive" or DBI).

1.1.1 Task 1 Overview

The purpose of the Task 1 analysis is to determine both the revenue requirements of the types of projects deployed in Massachusetts, as well as their "effective" incentive requirement. The total system revenue requirement is the levelized per MWh revenue over a project's life needed to fund the total upfront (capital and interconnection) and ongoing costs (including O&M) and meet investor minimum

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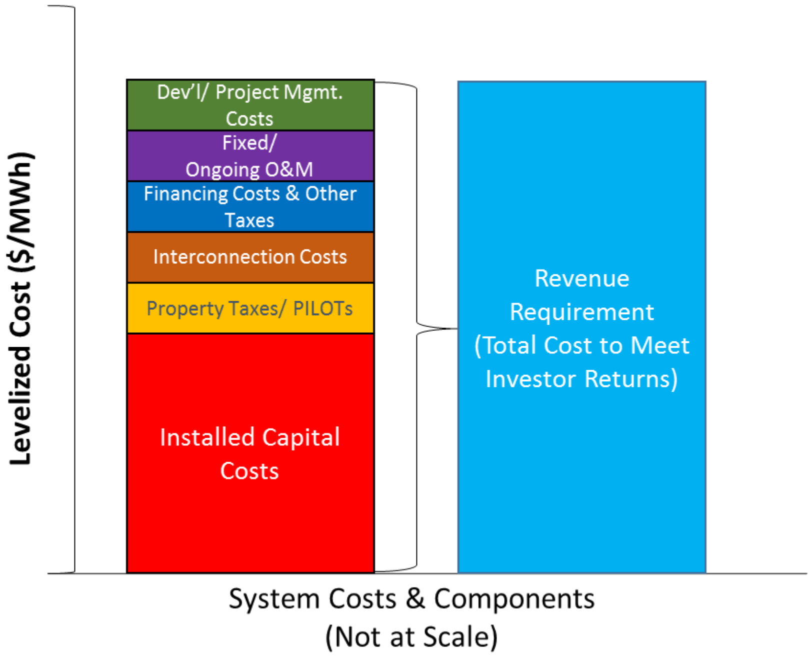
[8] The three distinct policy options as assessed were selected by DOER for modeling purposes only. As defined, they do not necessarily reflect the exact policies under consideration by DOER, but are rather being examined to illuminate distinctions between three general solar policy approaches that have been implemented in Massachusetts and other jurisdictions, while holding most other factors constant. In practice, many specific design parameters may be altered to achieve specific desired results.

[9] In this context, bundled refers to the purchase of electricity commodities (as described further below) and renewable energy credits (RECs).

returns in order to deploy the system over a 25 year period. Figure 1 illustrates the components of the levelized revenue requirement.

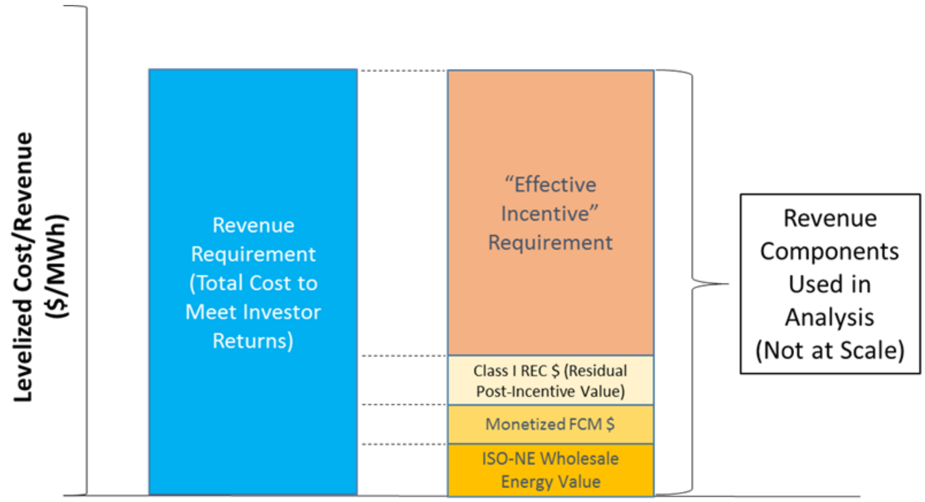
Figure 1 - Illustration of Revenue Requirement Components



In contrast, the effective required incentive level, as shown in Figure 2 represents the incentive revenue required to fill the gap between the revenue requirements and revenues available from market sources. As discussed further below, this analysis assumes that the value of production is the wholesale value of energy for all PV installations, in order to isolate the solar policy evaluation from a dynamic and heterogeneous net metering compensation landscape.

While in practice, the solar program incentive needed may be less for systems that consume solar PV energy behind-the-meter (or that continue to receive net metering credits), the total "effective" incentive represents the total cost to ratepayers of ensuring that each type of system can meet investor returns, including both solar incentives and net metering costs.

Figure 2 - – Illustration of Calculation of Ratepayers' "Effective Incentive" Requirement



For Task 1, data for evaluation of current PV costs was compiled from a number of sources, including (see the funnel in Figure 3):

- A survey of market participants who are active in the Commonwealth regarding installation capital expenditures, operating and financing costs;
- A sampling of representative Massachusetts utility interconnection costs from interconnection service agreements (ISAs);
- Third-party estimates of balance-of-system costs, including detailed analysis of recent costs and cost trajectories provided by Greentech Media's GTM Research unit; and,
- Upfront and operating cost estimates compiled by SEA in the context of its ongoing research of the Massachusetts, regional and national PV markets.

The revenue and incentive levels required for a solar PV owner to meet its threshold investment requirements were calculated utilizing a modified version of the publically available National Renewable Energy Laboratory's (NREL's) Cost of Renewable Energy Spreadsheet Tool (CREST)[10]. The CREST model establishes the total incentive value necessary for a range of projects to cover their costs and achieve a necessary economic rate of return to system owners and investors. The required revenue and incentive levels vary depending on the policy alternative being analyzed, due to factors such as varying risk and duration. Thus, a particular project type (e.g., a third party owned 1 MW landfill project) will have different revenue requirement under different policy alternatives.

For this analysis, SEA considered the following parameters:

- 34 different project classes (e.g., small residential roof mount, medium landfill, onsite affordable housing);
- Three solar PV cost scenarios (base, low, high);
- Three future policy alternatives (SREC-III, Hybrid Standard Offer / Competitive Bid, and Declining Block Incentive [DBI]); and,

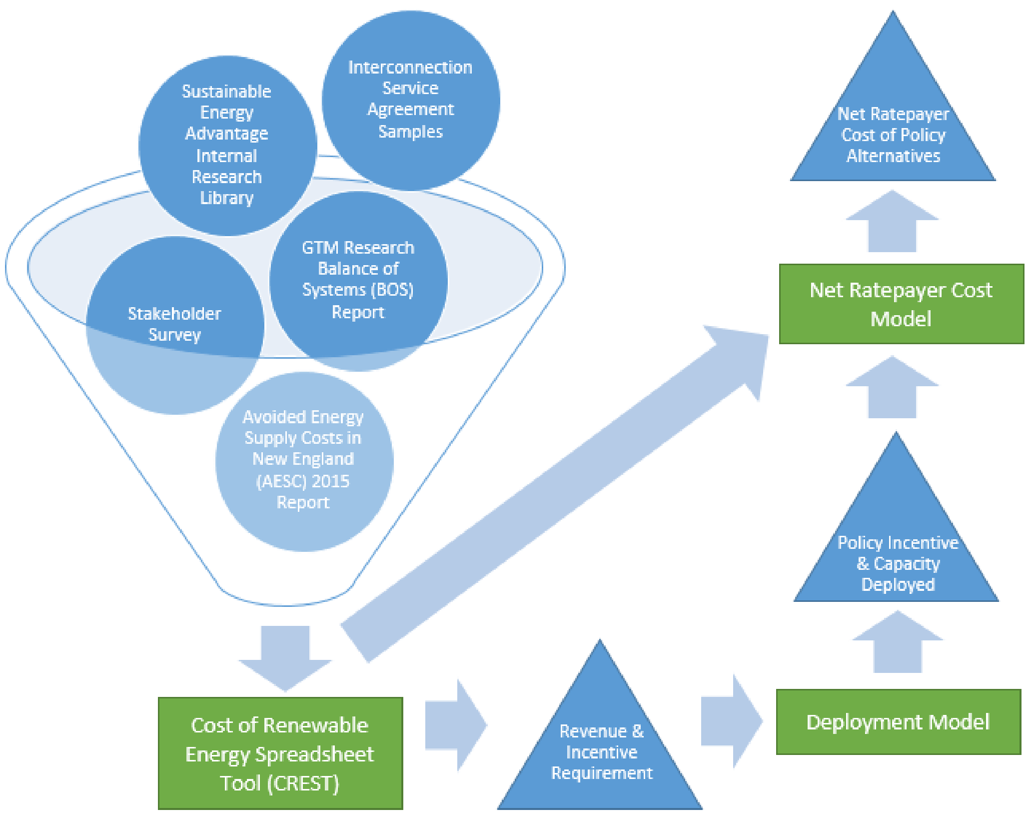
[10] See Section 3.1.4.1 for further discussion of the CREST model.

- Two alternative program durations (10 & 20 years[11]).

The analysis was conducted over a time horizon spanning the calendar years 2017 through 2022.

1.1.2 Task 2 Overview

Figure 3 – Schematic of Modeling Flow



Task 2 uses the Task 1 results (the "Revenue & Incentive Requirement" results triangle in Figure 3) as inputs to estimate the aggregate (net) direct ratepayer costs of each policy alternative. While a policy target (in total MW installed) has yet to be established by DOER, for Task 2, DOER directed SEA to assume that the goal of the successor program was to install 1,600 MW_{DC} over six calendar years. SEA created a project deployment schedule to meet these targets based on installation targets constrained by aggregate technical potential and year-over-year growth rates for each of fifteen "Competition Groups", in order to reflect a policy goal of maintaining project diversity and simulate a deployment trajectory of installations comprised of defined number of MWs of various project types installed over

[11] The SREC-III BAU policy future was not examined under a 20-year incentive case.

time to reach the 1600 MW target.[12] Project Types are modeled as competing *within* their respective Competition Group, with individual Project Types deployed based on cost. While each of the policy alternatives use the same population of Project Types, the incentive requirements for a specified Project Type will vary by policy alternative. For example, SEA assume that revenue under an SREC-III model is less certain, and therefore investment more risky, than revenue from the other policy alternatives which is by definition fixed over a defined incentive term.

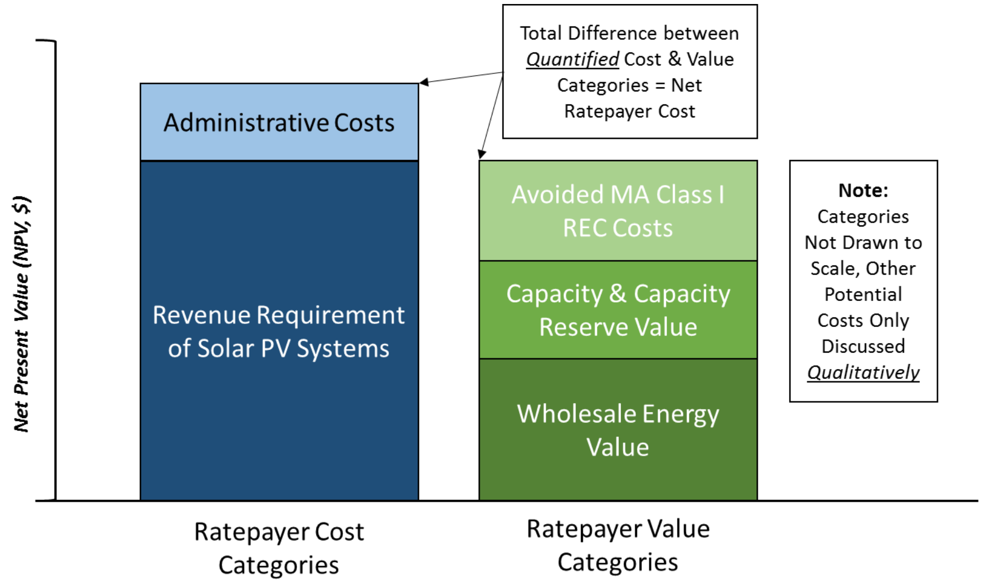
Based on projected deployment levels for each project type, the next step involves tallying the total net incentives paid by ratepayers under each policy alternative (see the green "Net Ratepayer Cost Model" rectangle in Figure 3). Figure 4 provides an overview of components that are used to calculate net direct ratepayer impacts and are used in the green "Net Ratepayer Cost Model" rectangle in Figure 4. Administrative costs, which vary by policy alternative, are added to the ratepayer impacts. Finally, SEA subtracts out costs that are directly avoided by the various policies: avoided Class I REC purchases, as well as capacity and wholesale energy market value. Once these values are subtracted from total program costs, the net cost of the program to ratepayers can be determined.

A notable difference between the policy alternatives is that the DBI and Competitive Bid policies (i.e., bundled alternative policies) assume that environmental attributes (Class I RECs, in both cases) and related energy and capacity are purchased as a bundle. However, the SREC-III policy alternative reflects a policy mechanism providing only purchase revenue for environmental attributes (denominated as SRECs), with other revenues or values flowing to generation owners separately.

Finally, we note that there will be policy 'transition costs' costs associated with market disruptions (e.g., hiring, setting up administrative processes, educating market participants including financiers, etc.) as Massachusetts transitions to a successor program. These costs, which would be expected to vary between policy alternatives, also might be considered, but are difficult to quantify and have not been quantified in this analysis.

[12] Competition Groups are differentiated by Market Sector and Size Category. See Table 24 for a complete list of Competition Groups.

Figure 4 – Overview of Costs and Values Used in Calculation of Net Direct Ratepayer Impacts



The balance of this section discusses issues and assumptions that frame the analysis.

1.2 Legislative Requirements for Program Development

While this project commenced prior to enactment of Chapter 75 of Session Laws 2016 – An Act Relative to Solar Energy (An Act Relative to Solar Energy, 2016) the analysis is aligned with many of the statute's requirements for a successor program for SREC-II. As excerpted from the statutory text, the law directs DOER to "design a program as part of a public process" that:

- *Promotes the orderly transition to a stable and self-sustaining solar market at a reasonable cost to ratepayers;*
- *Considers underlying system costs including, but not limited to, module costs, balance of system costs, installation costs and soft costs;*
- *Takes into account electricity revenues and any federal or state incentives;*
- *Relies on market-based mechanisms or price signals as much as possible to set incentive levels;*
- *Minimizes direct and indirect program costs and barriers;*
- *Features a known or easily estimated budget to achieve program goals through use of a declining adjustable block incentive, a competitive procurement model, tariff or other declining incentive framework;*
- *Differentiates incentive levels to support diverse installation types and sizes that provide unique benefits including, but not limited to, community-shared solar facilities and municipally-owned solar facilities and which may include differentiation by utility service territory, the location or the size of the solar renewable energy generating source;*
- *Considers environmental benefits, energy demand reduction and other avoided costs provided by solar renewable energy generating facilities;*

- *Encourages solar generation where it can provide benefits to the distribution system; and*
- *Promotes investor confidence through long-term incentive revenue certainty and market stability* (An Act Relative to Solar Energy, 2016).

Thus, the statute's requirement to ensure the program represents a "reasonable cost to ratepayers" seems to suggest that the General Court, as we note in Section 1.5.2, desires a clear accounting of the net direct ratepayer costs associated with the key policy alternatives. Finally, the legislation specifies that RECs created by systems qualified under the new program are to be used for RPS (presumably Class I) compliance.

1.3 PV Project Types Evaluated

As part of our modeling, SEA calculates the revenue requirements and needed incentives for 612 separate project types, where each is deployed depending on its cost effectiveness relative to other competing project types. SEA employed:

- 34 different project classes (which are folded into Rooftop Solar, Community Shared Solar, Landfill Solar, Brownfield Solar, Affordable Housing Solar, Solar Canopies and Large-Scale Greenfield solar market sectors); and
- Three different ownership cases (third party, host and public ownership).

.The full list of modeling project type constituents are found below in Table 1.

Table 1 – Modeling Project Type Constituents

Project Class	Cost	Ownership Type
Residential Roof Mount Small Commercial Roof Mount Medium Scale Solar Canopy (<1 MW) Large Scale Solar Canopy (>=1 MW) Commercial Emergency Power Community Shared Solar On-Site Affordable Housing Off-Site Affordable Housing Small Building Mounted Medium Building Mounted Large Building Mounted Medium Ground Mounted BTM Large Ground Mounted BTM Small Landfill Medium Landfill Large Landfill Small Brownfield Medium Brownfield Large Brownfield Medium Managed Growth Large Managed Growth	Low Cost Medium Cost High Cost	Third Party-Owned Host-Owned Public-Owned

1.4 General Description of Modeled Policy Alternatives

In contrast to a grant, rebate or other up-front incentive, as under the Massachusetts Clean Energy Center's prior Commonwealth Solar incentives, all of the policy futures examined here are performance-based incentives (PBIs), which require that installations actually produce energy, with incentives paid out on a per-MWh produced basis. The policies that were modeled for this analysis include:

SREC-III BAU*:* This potential policy closely resembles the SREC-II program, with the following exceptions:

- The SREC-III policy has lower alternative compliance price (ACP) rates and lower clearinghouse auction prices than SREC-II (that is, they are reset at a lower initial level and then continue to decline, as in SREC-II)

Hybrid Competitive Bid/Standard Offer (Hybrid CB/SO): This policy alternative would involve a long-term, bundled fixed-price contract or tariff, with 1) pay-as-bid **Competitive Bidding** (i.e., Competitive Solicitation) for large projects (defined as 250 kW or larger) and 2) an administratively-determined **Standard Offer** for smaller projects. For the purposes of this analysis:

- The Competitive Bid or solicitation for large projects would resemble the procurements for installations greater than or equal to 250 kW under the Rhode Island Renewable Energy Growth (REG) program. More generally, this represents a procurement of solar PV by an electric distribution company (EDC) under a long-term contract or tariff to purchase bundled energy, capacity and RECs using a utility (or utility-backed) auction or single-bid solicitation process. Access to such a contract or tariff would only be assured for winning bidders at the winning bid price (i.e., pay-as-bid).
- For small projects the bundled compensation (energy, capacity & RECs) would resemble the Rhode Island REG program for projects smaller than 250 kW, which receive a non-competitive, administratively determined standard offer fixed price tariff for 15 or 20 years.

Declining Block Incentive (DBI): This alternative would feature a long-term fixed-price bundled **Standard Offer** made via either tariff or contract through a declining block Incentive program.

- This iteration of a DBI program establishes a fixed, volume-based schedule whereby incentives are provided at higher levels to projects developed initially, with incentives adjusted downward in successive incentive 'blocks' of additional projects (constituting a MW quantity of project capacity available at a specified incentive level). Once sufficient capacity has been fully reserved, the program transitions to a lower incentive tier. This process continues until the total program volume has been reserved.

Table 2 summarizes the major characteristics which vary by Policy Alternative.

Table 2 – Characteristics of Future Policy Alternatives Considered

Characteristic	Hybrid Competitive Bid / Standard Offer	DBI	SREC-III
Duration Modeled	10 years[13]	10 & 20 years	
Net Metering Available	Yes, but only at wholesale rates		
Direct Ratepayer Impact Incentive	Large: Competitive/pay-as-bid > 250 kW, Small: Standard Offer <= 250 kW	Set by *projected* marginal effective incentive requirement	Average SREC market clearing price
Incentive as Valued by Project Owner / Developer	Not discounted	Not discounted	Discounted for financeability and brokerage fees
Segmentation	Large: Competitive Bid w/in defined Competition Groups Small: Differentiated SO by Project Type	Differentiated SO by Project Type	Market-wide Head-to-head competition, with market sectors (composed of project types) differentiated by SREC factors[14]
Project Goal	Additional 1600 MWs for successor program by end of 2022		

1.5 Key Disclaimers Associated With This Analysis

1.5.1 Policy Options Modeled vs. Policy Options under Consideration

The three distinct policy options assessed were selected for modeling purposes only. They do not necessarily reflect policies under consideration by DOER, but are rather being examined in an attempt to understand and draw distinctions between three general solar policy approaches that have been implemented in Massachusetts and other jurisdictions, while holding most other factors constant. In practice (as is discussed in great detail in Section 6) in many specific design parameters may be altered to achieve the goal of ratepayer cost reduction (or other objectives).

1.5.2 Scope and Purpose of Net Ratepayer Cost Analysis

While PV systems provide many ancillary benefits that are similar across policy alternatives - which is implicitly why the Commonwealth has provided incentives for PV installations - many such benefits do not directly accrue to ratepayers. The purpose of this analysis is to evaluate the relative net present value (NPV) of the net direct cost to ratepayers of each of the policy alternatives under discussion so as to aid DOER in understanding the relative costs to ratepayers of varying incentive programs. **As a result, this analysis is not intended as a 'value of solar analysis' for Massachusetts, nor as a cost benefit**

[13] For SREC-III, there is only a single 20 year sensitivity, instead of the full modeling.
[14] SREC Factors are the number of SRECs/MWh used to address to both differences in needed incentives and to express policy preferences for market diversity.

analysis incorporating the direct and indirect costs and benefits of solar PV or net metering in Massachusetts.

1.6 Structure of this Report

This report is broken into five additional sections.

- Section 2 is a summary of SEA's technical performance assumptions regarding PV systems in Massachusetts, including capacity factors, system useful lives, production and technology selection.
- In Section 3, we detail the assumptions and results of the Task 1 system cost analysis. While Section 3.1 contains SEA's detailed assumptions for the cost analysis (including the results of a survey of market participants undertaken by SEA, which was used to develop SEA's key assumptions for the cost analysis), Section 3.2 details selected cost analysis results and the factors driving those results.
- Section 4 includes the assumptions and results of the Task 2 net ratepayer cost analysis of each policy alternative. In Section 4.1, SEA describes the methodology and assumptions driving its calculation of the net cost to ratepayers, including its assumed deployment of 1,600 MW_{DC} PV systems across market sectors between 2017 and 2022 and the categories of net ratepayer costs calculated in the analysis. Section 4.2 includes the net ratepayer cost results by policy alternative (and by potential approach to monetizing federal incentives), as well as why the 10-year incentive program results are lower than the 20-year results.
- In Section 5, SEA describes a series of policy and market risks that are not quantified in the analysis, including several that may result from DOER's choice of policy alternative.
- Finally, in Section 6, SEA concludes by detailing the limitations of the analysis, and how it might be made more robust by taking certain future analytical approaches and steps.

2 Overarching Performance Assumptions

2.1.1 Technology Assumption

The vast majority of systems installed and planned in Massachusetts continue to feature a fixed-tilt, south-facing orientation, with few single- or dual-axis systems deployed. For purposes of estimating the incentive levels, SEA assumed that all projects were fixed-tilt rather than single- or dual-axis tracking systems. If the increased costs and increased revenues associated with installing tracking were equal (breakeven), the calculated incentive level would be roughly sufficient to support a tracking system as well.

2.1.2 Capacity Factor, System Life and Production Degradation

The assumed capacity factors, which reflect a mixture of model results from National Renewable Energy Laboratory's PVWatts model and other information obtained in the course of the Rhode Island Renewable Energy Growth (REG) Ceiling Price development process, are shown for each market segment in Table 3. These capacity factor values are expressed relative to installed kW_{DC} (Office of Energy Resources, 2015). The capacity factor for each project size was held constant over time.[15]

Table 3 - Assumed Capacity Factors by System Size (kW_{DC})

Modeled System Size Ranges (kW_{DC})	Capacity Factor
7-15	**13.49%**
100-500	**13.52%**
1000-4000	**14.18%**

Each system SEA assumes would deploy in response to program incentives has a 25 year economic life. For each project, energy production, as well as maximum AC output, is expected to degrade at a rate of 0.5% per year.

2.1.3 Production Profile

For the purposes of estimating available wholesale revenue for PV installations realizing revenue in the wholesale market, SEA assumed a typical PVWatts profile for Worcester, MA and a capacity factor of 14% DC for estimating a production-weighted energy market value for electricity sales at wholesale**.**

3 Task 1: Evaluation of Current Solar Costs and Needed Incentive Levels across Sectors

3.1 Task 1 Assumptions and Methodology

3.1.1 Data Gathering from Massachusetts Solar Market Stakeholders

In order to elicit the detailed information on various factors that affect solar PV project development and the successor for the SREC-II program, SEA conducted a two part survey, comprised of:

- A primarily qualitative web-based survey elicited information on each respondent's assessment of:
  - Their role and involvement in the SREC-II market;
  - The technical potential for future development for various market sector and size categories(e.g., 25-250 kW rooftop, > 1 MW landfill);

[15] In general, larger projects tend to be more optimally oriented due south and configured for maximum production, while smaller systems (particularly rooftop systems) are impacted and sometimes limited by the orientation of the building and suboptimal tilts dictated by building-related factors.

        - Financing conditions, including the sensitivity of cost of capital and capital structure to various states' solar markets and policies; how the cost of capital varies with net metering compensation; and how the volatility of energy revenue compares to SREC revenues over time;
        - What market sector and size categories are worthy of special consideration (i.e., require greater incentives compared to other projects in its size category).
    - A quantitative survey eliciting information on respondent's assessment of:
        - Installed project costs (except interconnection) for various market sector and size categories;
        - Interconnection costs by various size categories;
        - O&M costs for various market sector and size categories;
        - Inverter replacement costs by various size categories;
        - Financing costs and parameters by policy alternative type and project size; and
        - Comparison for host owned vs. third part owned financing parameters for two prototypical projects.

The survey script and spreadsheet form are provided as separate report attachments[16].

With the help of DOER, SEA identified over 100 different organizations who were explicitly invited to respond to the survey. The survey request also was circulated by others (such as associations to their members) so it is unclear how many organizations ultimately received an invitation to respond.

All responses were reviewed, and many clarification calls and emails ensued in order to improve the quality of responses. In the end, 47 useable qualitative responses and 21 useable quantitative responses were received. In addition, interconnection cost data and administrative costs were elicited from DOER, National Grid and Eversource.

Results of the surveys and research were used to inform inputs into the Cost of Renewable Energy Spreadsheet Tool (CREST) model (e.g., project costs and financing assumptions), deployment model (e.g., technical potential constraints on installed capacity, the financing of SREC revenue), and separate model used to compute the net aggregate direct ratepayer impacts (including administrative costs).

3.1.2 Highlights of the Qualitative Survey Results

A summary of the role of the respondents' organization's role in the industry is provided in Table 4. Organizations that take the role of "Developer", "Installer / EPC / Integrator", and "Equity Investor" clearly dominate.

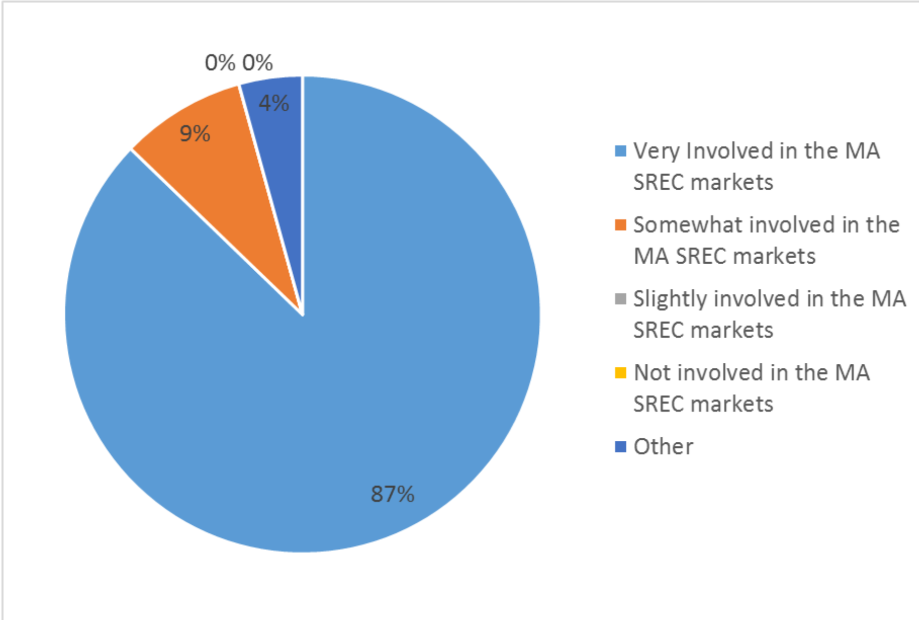
[16] The survey script file is "DOER Post-1600 MW Solar Survey Script.pdf" and the spreadsheet form file is "Survey_Cost_Data_Entry_040416_VFinal.xlsx"

Table 4 – What Role(s) Does Your Organization Play in the Solar Energy Industry?

Answer Options	Response %	Count
Developer	68.1%	32
Installer / EPC / Integrator	42.6%	20
O&M Provider	29.8%	14
Project Management	36.2%	17
Equity Investor	42.6%	20
Tax Equity Investor	14.9%	7
Lender / Debt Provider	8.5%	4
Offtaker - SRECs / RECs	10.6%	5
RPS Obligated Entity - Competitive Supplier	6.4%	3
Wholesale Market Participant	2.1%	1
Manufacturer	2.1%	1
Distributor	2.1%	1
Service Provider (e.g., engineering, legal support, permitting support)	14.9%	7
Project Host	6.4%	3
Project Aggregator	6.4%	3
Other	12.8%	6

Figure 5 displays the respondent's level of experience in the MA SREC market. As can be seen almost all the respondents (87%) described themselves as very involved in the SREC market. The survey structure did not allow SEA to determine from the responses how non-participants in the MA SREC market view the market structure differently from participants. For example, someone might have been slightly involved or not involved in the MA SREC market because they felt the SREC policy incentives were too risky or not financeable. This potential self-selection bias should be kept in mind when reviewing all the survey results.

Figure 5 – What Has Been The Nature of Your Participation (Level Of Experience) in the Massachusetts SREC Carve-Out Markets to Date? (n=47)



The survey asked respondents to assess whether there were material constraints to further development of various solar market sectors where

- 1= No, no constraints
- 2= Yes, future projects will be moderately more expensive / difficult to develop
- 3= Yes, future projects will be substantially more expensive / difficult to develop
- 4= Yes, are about to hit saturation; there just aren't that many opportunities to develop this type of project

The mean response to the questions on this 1 to 4 scale is provided in Table 5. The responses suggest that few market participants believe that the small < 25 kW (primarily residential) sector is nearing any limits. However, Affordable Housing > 1 MW and Landfills > 1 MW are examples of project types which respondents believe that future development will be significantly limited or more expensive (i.e., the low-hanging fruit has been picked). These responses are understandable; for example there are only so many large off-takers for affordable housing projects, and there are only so many suitable large closed landfills that are easily developable in the Commonwealth.

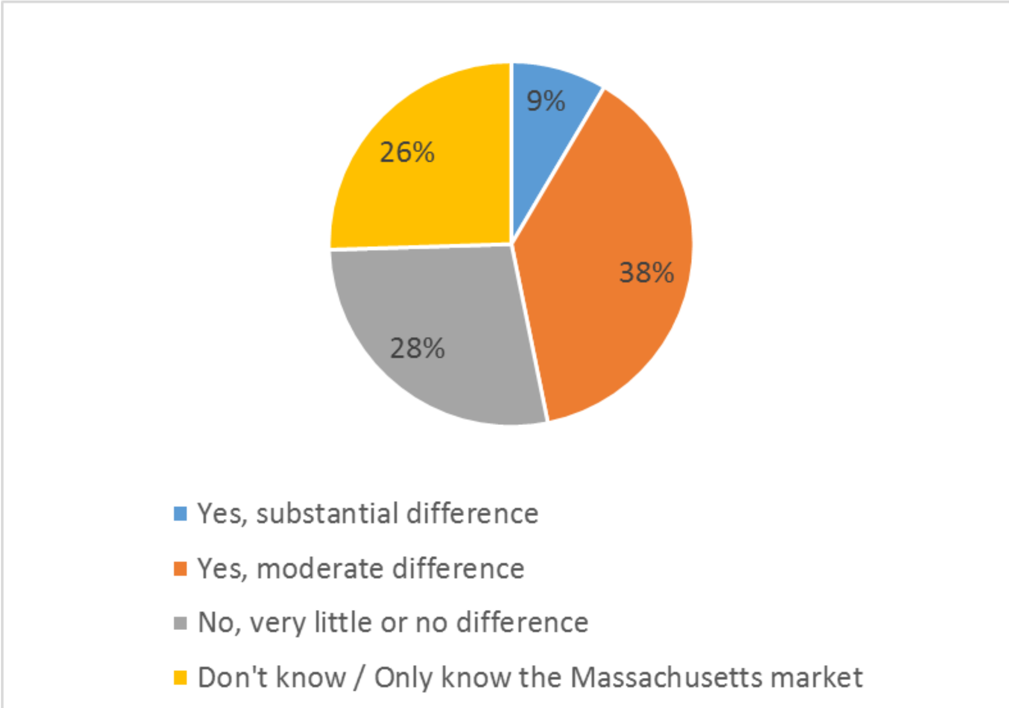
These inputs on development constraints were incorporated into our deployment model as limitations to technical potential that restrict development in some sectors.

Table 5: Average of Query to Market Sector and Size Category Technical Potential (1=No Constraints, 4=Nearing Saturation)

Market Sector and Size Category	Mean Response
Affordable Housing <25 kW	2.1
Affordable Housing 25-250 kW	2.5
Affordable Housing 250-1000 kW	2.8
Affordable Housing > 1MW	3.2
Rooftop <25 kW	1.5
Rooftop 25-250 kW	1.7
Rooftop 250-1000 kW	2.1
Rooftop > 1MW	2.6
CSS <25 kW	2.5
CSS 25-250 kW	2.3
CSS 250-1000 kW	2.2
CSS > 1MW	2.3
Landfill 250-1000 kW	2.7
Landfill > 1MW	3.0
Brownfield 250-1000 kW	2.7
Brownfield > 1MW	2.7

SEA then asked respondents to assess the difference between Massachusetts and other markets, asking "*Is there a difference in cost of capital or capital structure between the Massachusetts market and markets in other states (e.g., CT, RI, NY or NJ)?*" The responses are summarized in Figure 6. Almost half of the respondents felt there was a moderate or substantial difference, another 28% felt there very little or no difference, and 26% did not know (perhaps because they were not familiar with the other markets).

Figure 6 – Is there a difference in Cost of Capital or Capital Structure between the Massachusetts Market and Markets in other States (e.g., CT, RI, NY or NJ)? (n=47)



For the twenty respondents who answered there was a substantial or moderate difference, the survey asked two additional questions. Figure 7 shows the results for the question "*What Revenues Sources May Have Accounted for those Differences between MA and Other Markets?*" What is surprising about these responses is not that nine respondents pointed to SRECs as being 'more volatile / costly / difficult to hedge', while five thought they were 'less volatile / costly / difficult to hedge', but that net metering was viewed as being 'more volatile / costly / difficult to hedge' than SREC revenue (10 vs. 9 responses) and that fewer felt that net metering revenue was 'less volatile / costly / difficult to hedge' (3 vs. 5 responses). SEA speculates that the initial House-passed version of SB 1979 bill that would have implemented lower net metering revenue on both new and existing systems may have caused this greater perceived revenue uncertainty.

Similarly, SEA also asked "*What Market Structure May Have Accounted for those Cost of Capital or Capital Structure Differences between MA and Other Markets?*" Twelve out of twenty respondents felt that Massachusetts is "less stable / less mature" than other markets, while respondents were evenly split over whether Massachusetts was more or less mature than other markets (see Figure 8).

Figure 7 – What Revenues Sources May Have Accounted for those Differences between MA and Other Markets? (Q9, N=20)

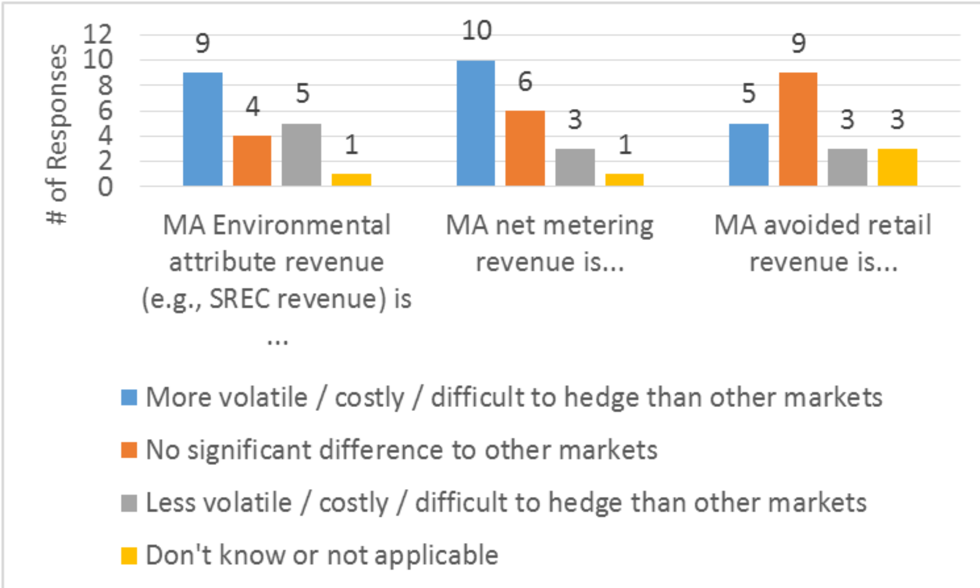
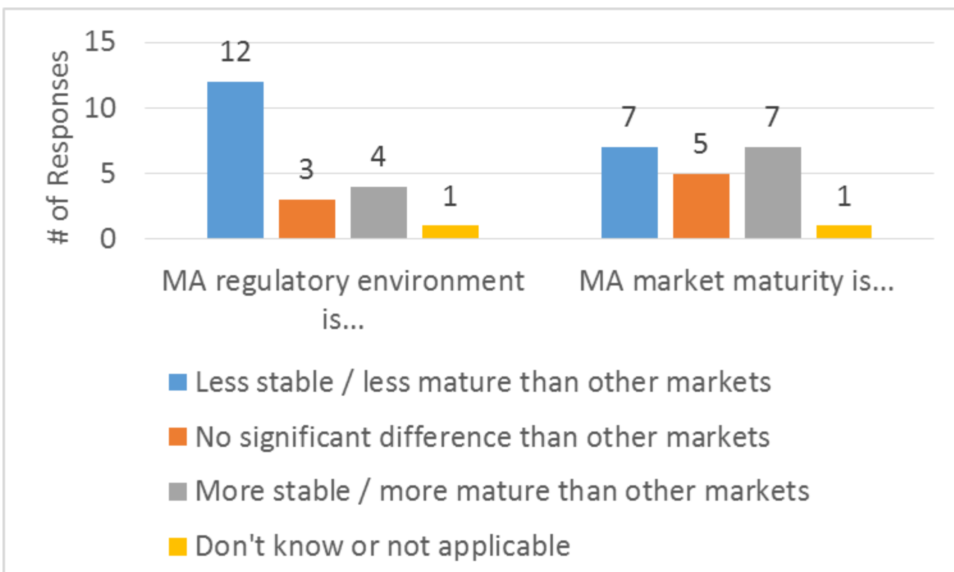


Figure 8 – What Market Structure May Have Accounted for those Cost of Capital or Capital Structure Differences Between MA And Other Markets? (Q9, n=20)



The survey next asked: "*In relative terms, how do the structure of competitive bid markets (e.g., CT ZREC and RI REG) compare to the MA SREC market in terms of the impact on the following cost categories? The Competitive Bid Markets have …*". The responses for two different size categories are found in Figure 9 and Figure 10. The most striking element is that for most cost categories, similar costs predominate, the primary exception being that market customer acquisition costs are skewed to being more expensive under a competitive procurement structure.

Figure 9 – In Relative Terms, How do the Structure of Competitive Bid Markets (e.g., CT ZREC And RI REG) Compare to the MA SREC Market In Terms of the Impact on the Following Cost Categories? The Competitive Bid Markets have ... (250-1000 kW)

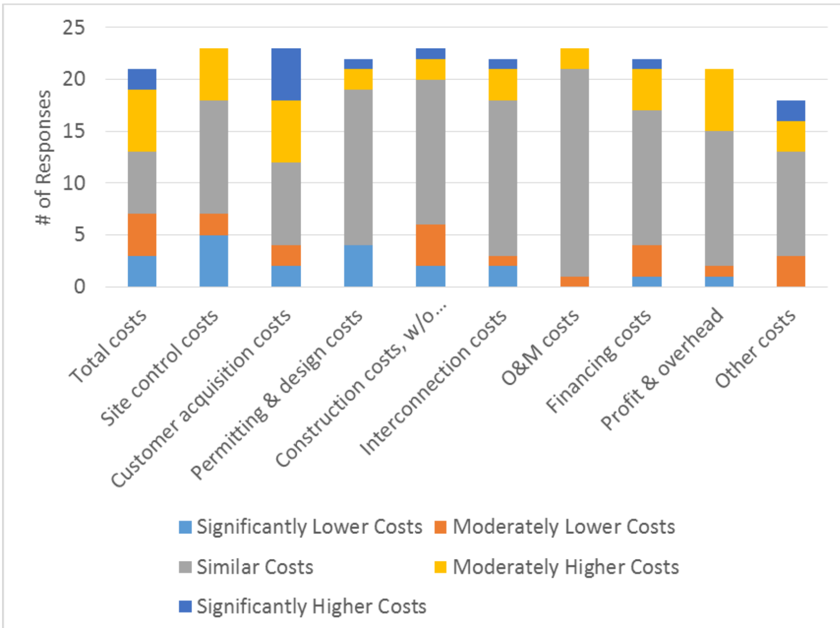


Figure 10 – In Relative Terms, How do the Structure of Competitive Bid Markets (e.g., CT ZREC And RI REG) Compare to the MA SREC Market In Terms of the Impact on the Following Cost Categories? The Competitive Bid Markets have … (1000+ kW)

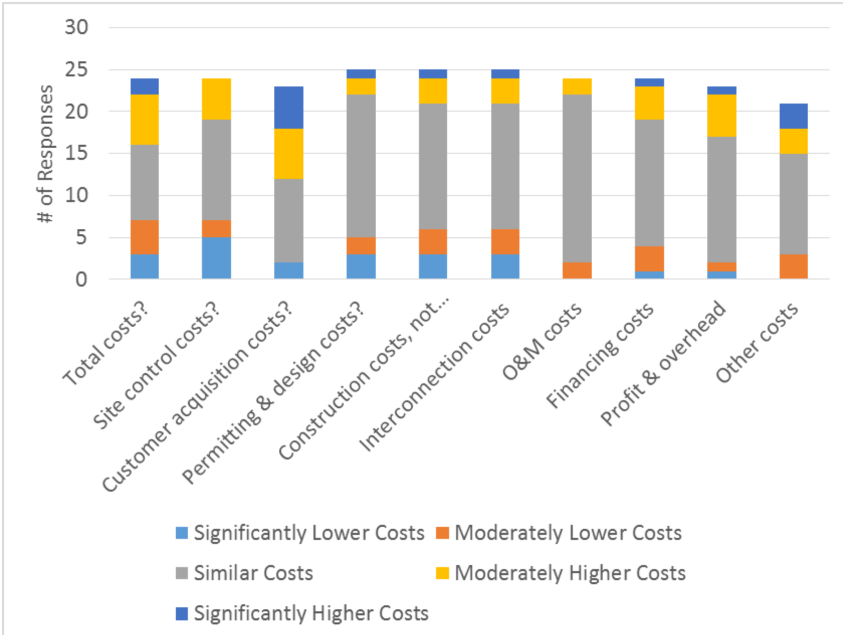
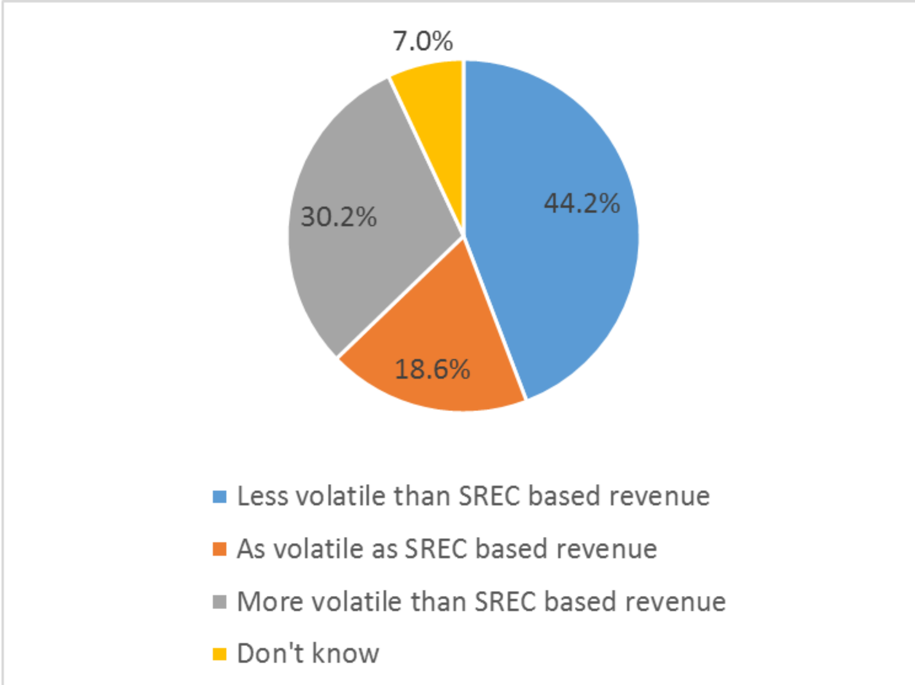


Figure 11 shows the results for a question that asked the relative risk of energy-based revenue compared to SREC-based revenue. Interestingly, almost half the respondents felt that energy-based revenue would be as volatile or more volatile as SREC-based revenue.

Figure 11 – How is the Relative Risk of Volatility in Energy Based and SREC Based Revenue over Time Reflected in the Capital Structure and Cost of Capital over Time? Over Time, Energy Based Revenue is Expected to be …… (n=43)



3.1.3 Survey Results Regarding System Costs

SEA also surveyed solar market stakeholders on quantitative cost data. This survey elicited information on the respondents' range of recent PV system costs differentiated by project size, project type, and ownership type (where applicable). Data was sought for the market sectors and sizes shown in Table 6.

Table 6: Cost Survey Market Sectors and Sizes

Market Sector	Size Category (DC)	Ownership Case
Ground-Mount Solar Brownfield Solar Community Shared Solar Landfill Solar Solar Canopy Rooftop Solar Affordable Housing Solar	< 25 kW 25 – 250 kW 250 kW – 1 MW > 1 MW	Third Party-Owned Host-Owned Public-Owned

The quantitative responses received from market participants are discussed in the following subsections.

3.1.3.1 *System Installed Costs*

Survey respondents were asked to provide the low and high of their 2015-2016 total project cost range, excluding interconnection, for third-party and host-owned systems for each market sector and size category, as applicable.[17] The survey defined total project costs as the total expected all-in project cost exclusive of interconnection, including all hardware, balance of plant, design, construction, permitting, development (including development fees), interest during construction, financing costs and reserves.[18] SEA separately took the means of (i) the low end of the range responses, and (ii) the high-end of the range responses. Table 7 and Table 8 below show the mean of the low end responses (Low End of Range), and the mean of the high end responses (High End of Range) for system installed cost responses, respectively, for third-party-owned and host-owned systems.

Many of the trends one would expect to see can be discerned from the tables below.

- Rooftop and Ground Mount installations are the most cost-effective for their size categories;
- $/W$_{DC}$ installed costs decrease as system size increase;
- There is no particular trend of host-owned system installed costs vs. third-party owned system installed costs. Differences are likely more a function of which respondents provided a response than significant differences in actual costs;
- Affordable Housing and Community Shared Solar systems over 250 kW have very similar installed costs to Ground Mount systems (no surprise as those systems would be ground mounted at the size category and the cost differences show up under other cost categories);
- Brownfield and Landfill projects have a cost premium compared to Ground Mount systems; and
- Solar Canopy systems have the highest installed costs by a wide margin.

Table 7 – System Installed Costs Responses – Third-Party-Owned $/W DC

Market Sector	*< 25 kW*		*25 -250 kW*		*250 kW - 1 MW*		*> 1 MW*	
	Low End of Range	*High End of Range*	*Low End of Range*	*High End of Range*	*Low End of Range*	*High End of Range*	*Low End of Range*	*High End of Range*
Ground-Mount Solar			$3.56	$5.26	$2.34	$2.97	$2.20	$2.67
Brownfield Solar					$2.45	$3.12	$2.46	$2.96
Community Shared Solar			$3.63	$5.46	$2.39	$3.15	$2.28	$2.84
Landfill Solar					$2.54	$3.10	$2.55	$3.08
Solar Canopy			$3.67	$5.02	$3.10	$3.77	$3.01	$3.61
Rooftop Solar	$3.66	$4.68	$2.67	$3.71	$2.20	$2.89	$2.07	$2.66
Affordable Housing Solar	$4.25	$5.05	$2.75	$4.50	$2.40	$3.08	$2.24	$3.06

[17] Respondents were asked for low-end of range and high-end of range because asking for input this way (vs. e.g., asking for the average cost) would be less burdensome and less likely to trigger non-response because of aversion to revealing confidential market information while still providing insight into distribution of costs.

[18] The total project cost (as defined for the purposes of the survey) was not intended to reflect any tax incentives, grants or other cash incentives, which are accounted for separately.

Table 8 –System Installed Cost Responses – Host-Owned

Market Sector	*< 25 kW*		*25 -250 kW*		*250 kW - 1 MW*		*> 1 MW*	
	Low End of Range	*High End of Range*	*Low End of Range*	*High End of Range*	*Low End of Range*	*High End of Range*	*Low End of Range*	*High End of Range*
Ground-Mount Solar	$4.34	$5.83	$3.58	$4.64	$2.45	$3.02	$2.13	$2.63
Brownfield Solar					$2.58	$3.17	$2.60	$3.21
Community Shared Solar			$3.52	$4.97	$2.51	$3.24	$2.24	$2.89
Landfill Solar					$2.55	$3.18	$2.61	$3.20
Solar Canopy	$5.50	$7.00	$3.98	$5.35	$3.20	$3.84	$3.05	$3.61
Rooftop Solar	$3.48	$4.66	$2.73	$3.74	$2.29	$2.97	$1.99	$2.61
Affordable Housing Solar	$3.78	$4.92	$2.88	$4.50	$2.23	$3.15	$2.12	$3.15

3.1.3.2 *Interconnection Costs*

Survey respondents were asked to provide the low and high end of their 2015-2016 interconnection cost range for each of the market sector and size categories. The survey defined interconnection costs as including all costs relating to connecting to the grid, such as construction of transmission lines and (as applicable) transformers, breakers and other related equipment, permitting and construction costs of the utility, and start-up costs. Table 9 below shows the mean of the low end responses (Low End of Range) and the mean of the high end responses (High End of Range) for interconnection costs.

The most striking observation about Interconnection Costs is the wide difference between the low and high ends of the range. Interconnection can be relatively inexpensive if there are no utility upgrades or construction costs. Conversely, utility costs can be the wildcard that adds a significant cost premium to system development. Figure 19 displays the wide variability of a sample of utility interconnection costs in $/Watt from a sample of over 150 interconnection service agreements. This figure provides additional support for this observation. The least expensive interconnections can be for the < 25 kW size category when the Low End of Range responses vary from $0.01 to $0.03 /W DC. The High End of Range responses vary with seemingly little rhyme or reason across market sector and size category. Upon inspection of the individual responses, the wide variation of the High End of Range responses is driven by outliers with sometimes very high $/W interconnection costs.

Table 9 – Interconnection Cost Responses - $/W DC

Market Sector	*< 25 kW*		*25 -250 kW*		*250 kW - 1 MW*		*> 1 MW*	
	Low End of Range	*High End of Range*	*Low End of Range*	*High End of Range*	*Low End of Range*	*High End of Range*	*Low End of Range*	*High End of Range*
Ground-Mount Solar	$0.02	$0.51	$0.08	$0.51	$0.10	$0.37	$0.09	$0.36
Brownfield Solar	$0.01	$0.10	$0.10	$0.30	$0.07	$0.41	$0.09	$0.37
Community Shared Solar	$0.01	$0.10	$0.10	$0.28	$0.08	$0.43	$0.10	$0.40
Landfill Solar	$0.01	$0.10	$0.10	$0.29	$0.09	$0.39	$0.10	$0.36
Solar Canopy	$0.03	$0.30	$0.10	$0.43	$0.08	$0.46	$0.10	$0.42
Rooftop Solar	$0.02	$0.35	$0.11	$0.42	$0.08	$0.34	$0.09	$0.34
Affordable Housing Solar	$0.03	$0.53	$0.08	$0.33	$0.10	$0.36	$0.10	$0.36

3.1.3.3 *Ongoing O&M Costs*

Survey respondents were asked to provide the low and high end of their 2015-2016 ongoing operations and maintenance (O&M) cost range for third-party and host-owned systems for each market sector and size category. The survey defined ongoing O&M costs as the levelized annual operations and maintenance cost in nominal dollars, including all labor, management, equipment, plus insurance, land lease, property taxes/PILOTs, decommissioning surety or reserve, but not including inverter replacement reserve which was accounted for separately. Table 10 and Table 11 below show the mean of low end responses (Low End of Range) and the mean of the high end responses (High End of Range) for ongoing O&M cost responses respectively for third-party and host-owned systems.

The Low End of Range responses and the High End of Range responses relating to O&M costs don't suggest a discernible pattern across size ranges. SEA expected to see some economies of scale as system size increased, but the survey showed no consistent trend. SEA speculates that level of O&M services can vary substantially, and the responses may not be an apple-to-apple comparison costs for similar services. One exception to the lack of a meaningful distinctions was that O&M costs for Community Shared Solar projects were as high (or higher) than comparable market sectors in the same size category. This is consistent with expectations that CSS projects will incur additional general and administrative costs associated with communications, crediting and replacing project participants, and accounting.

Table 10 – Ongoing O&M Cost Responses $/W DC/year – Third-Party-Owned

Market Sector	*< 25 kW*		*25 -250 kW*		*250 kW - 1 MW*		*> 1 MW*	
	Low End of Range	*High End of Range*	*Low End of Range*	*High End of Range*	*Low End of Range*	*High End of Range*	*Low End of Range*	*High End of Range*
Ground-Mount Solar	$0.06	$0.08	$0.05	$0.22	$0.04	$0.07	$0.04	$0.07
Brownfield Solar					$0.03	$0.06	$0.03	$0.06
Community Shared Solar					$0.04	$0.08	$0.05	$0.09
Landfill Solar					$0.02	$0.06	$0.03	$0.06
Solar Canopy			$0.04	$0.14	$0.03	$0.06	$0.03	$0.07
Rooftop Solar	$0.05	$0.07	$0.06	$0.13	$0.04	$0.08	$0.04	$0.07
Low Income Solar	$0.07	$0.10	$0.03	$0.17	$0.04	$0.07	$0.04	$0.07

Table 11 - Ongoing O&M Cost Responses $/W DC/year – Host-Owned

Market Sector	*< 25 kW*		*25 -250 kW*		*250 kW - 1 MW*		*> 1 MW*	
	Low End of Range	*High End of Range*	*Low End of Range*	*High End of Range*	*Low End of Range*	*High End of Range*	*Low End of Range*	*High End of Range*
Ground-Mount Solar	$0.04	$0.05	$0.04	$0.13	$0.04	$0.08	$0.04	$0.07
Brownfield Solar			$0.02	$0.18	$0.02	$0.06	$0.02	$0.05
Community Shared Solar			$0.02	$0.18	$0.04	$0.08	$0.05	$0.09
Landfill Solar			$0.02	$0.18	$0.03	$0.07	$0.02	$0.05
Solar Canopy	$0.02	$0.10	$0.03	$0.12	$0.02	$0.06	$0.02	$0.05
Rooftop Solar	$0.03	$0.06	$0.05	$0.12	$0.04	$0.08	$0.04	$0.07
Low Income Solar	$0.02	$0.06	$0.02	$0.15	$0.04	$0.08	$0.03	$0.07

3.1.3.4 *Financing Costs*

Survey respondents were asked to provide typical financing costs and terms by size category for the three successor policy futures explored in this analysis. Financing costs were divided into permanent financing and construction financing.

Table 12 – Mean Financing Responses – SREC-III

	< 25 kW	25 - 250 kW	251 - 1,000 kW	> 1,000 kW
Permanent Financing:				
Debt:				
% of Permanent Financing	40.0%	40.0%	45.2%	46.7%
Debt Term (Years)	10	10	10	10
Interest Rate on Term Debt	5.5%	5.5%	5.6%	5.8%
Lender Fee (as %)	2.0%	2.0%	1.4%	1.3%
Target Average DSCR	1.30	1.30	1.42	1.36

Tax Equity:				
% of Permanent Financing	59.4%	44.7%	38.7%	26.8%
Target After-Tax IRR	8.8%	13.4%	14.4%	13.5%
Sponsor/Cash Equity:				
% of Permanent Financing	0.6%	10.3%	16.1%	28.2%
Target After-Tax IRR	20.0%	19.0%	14.0%	12.1%
Construction Finance:				
% Debt		45.0%	78.8%	71.7%
Interest Rate		7.5%	6.2%	6.8%
Target After-Tax IRR		8.0%	8.0%	8.0%

Table 13 – Mean Financing Responses – Hybrid Competitive Bid / Standard Offer

	Fixed Price Offer		Competitive Bid	
	< 25 kW	25 - 250 kW	251 - 1,000 kW	> 1,000 kW
Permanent Financing:				
Debt:				
% of Permanent Financing	50.0%	50.0%	46.7%	45.0%
Debt Term (Years)	10	10	12	12
Interest Rate on Term Debt	6.0%	6.0%	5.8%	5.8%
Lender Fee (as %)	1.5%	1.5%	1.3%	1.4%
Target Average DSCR	1.35	1.35	1.38	1.36
Tax Equity:				
% of Permanent Financing	30.0%	30.0%	31.7%	28.0%
Target After-Tax IRR	15.0%	15.0%	14.7%	13.8%
Sponsor/Cash Equity:				
% of Permanent Financing	20.0%	20.0%	21.7%	27.8%
Target After-Tax IRR	15.0%	15.0%	12.0%	11.9%
Construction Finance:				
% Debt	90.0%	80.0%	71.7%	75.0%
Interest Rate	7.3%	9.0%	7.0%	7.3%
Target After-Tax IRR	7.0%	9.0%	7.5%	8.3%

Table 14 – Mean Financing Responses – Declining Block Bundled Incentive

	< 25 kW	25 - 250 kW	251 - 1,000 kW	> 1,000 kW
Permanent Financing:				
Debt:				
% of Permanent Financing	50.0%	50.0%	42.7%	42.7%
Debt Term (Years)	10	10	11	11
Interest Rate on Term Debt	6.0%	6.0%	5.8%	5.8%
Lender Fee (as %)	1.5%	1.5%	1.3%	1.3%
Target Average DSCR	1.35	1.35	1.38	1.36
Tax Equity:				

% of Permanent Financing	30.0%	30.0%	34.0%	27.8%
Target After-Tax IRR	16.0%	16.0%	15.3%	12.8%
Sponsor/Cash Equity:				
% of Permanent Financing	20.0%	20.0%	23.3%	29.6%
Target After-Tax IRR	16.0%	16.0%	12.3%	11.4%
Construction Finance:				
% Debt	80.0%	80.0%	67.7%	67.7%
Interest Rate	9.0%	9.0%	6.8%	6.8%
Target After-Tax IRR	9.0%	9.0%	7.5%	7.5%

One might expect competitive bid and DBI to have the same financing costs, since each contract has the same risk profile. However, literature on standard offers/feed-in tariffs such as the DBI suggest that having a *programmatic* approach leads to streamlining and replication of financing in a way that competitive bid programs do not (Balchandani, Cavaliere, Van't Hof, & Buchanan, 2011) (New York State Research and Development Administration, 2012). Nevertheless, for ease of cost modeling, SEA assumes that both policy alternatives have the same financing costs (but not the same administrative costs).

3.1.4 Key Assumptions for Task 1 Cost Analysis

3.1.4.1 *Developing Revenue and Incentive Requirement Calculations: The Cost of Renewable Energy Spreadsheet Tool (CREST):*

To determine levelized cost of energy (LCOE) which serves as the basis for the "revenue requirement", and "effective incentive requirement" projections, SEA used the National Renewable Energy Laboratory's (NREL) *Cost of Renewable Energy Spreadsheet Tool* (CREST). The CREST model and supporting documentation, which were developed by SEA, are available from the NREL website.[19] CREST is a publicly available and transparent tool that aids policymakers with estimating renewable energy costs for various public policy purposes, such as establishing cost-based or performance-based incentives.

For this analysis, SEA has augmented CREST with a large-scale batch processing function for market-scale revenue and incentive requirement modeling. The CREST model is used to solve for (i) an LCOE and/or (ii) an "effective incentive" (the amount exceeding the projected non-incentive revenue or value) that produces the minimum required revenue per unit of production for the modeled renewable energy project to meet its equity investors' assumed required after-tax return. For this analysis, in addition to the standard cost, performance, and financing inputs that would be used to calculate a LCOE, the model also incorporates projections of the market value of wholesale energy and (as applicable) capacity produced generated beginning with the first year of operation, as well as assumed Class I Renewable

[19] For more details regarding CREST and where to access it, please visit https://financere.nrel.gov/finance/content/crest-cost-energy-models.

Energy Credit (REC) revenue after the project no longer receives other incentives. The inclusion of this market value of production means that CREST solves for the minimum *additional* revenue required to achieve the specified project's defined after tax return on invested capital. In other words, the model calculates the required 10- and 20-year levelized incentives directly.

3.1.4.2 *Overarching Policy and Market Assumptions*

In order to estimate current and future incentive levels required to facilitate PV development, a suite of assumptions must be made. Key policy and market assumptions are discussed as follows:

- Chapter 75 of Session Laws 2016 altered the net metering rules through the expansion of caps and the establishment of "market net metering credits", but largely remains consistent with established law regarding net metering. In general, the analysis is consistent with this new law, with the following exceptions:
    - Under current rules BTM projects would reap full avoided retail rates, and most projects equal to or less than 25 kW_{AC} also would continue to receive current Class I net metering credits (which include the EDC's default generation service, transmission, transition and distribution rate components). Nonetheless, in order to create a straight-forward apples-to-apples comparison of Policy Alternatives for this analysis, the incentive requirement value SEA calculates is the "effective" incentive borne by ratepayers for the program. This effective incentive is equal to the total revenue requirement less the wholesale energy, any monetized capacity value[20] and a pro forma value for MA Class I RECs. The effective incentive is, thus, inclusive of net metering credit value and the avoided value of retail charges for BTM projects. This means the effective incentive does not necessarily represent at what level the incentive from a Policy Alternative would need to be set at (e.g., SREC level or tariff rates) because part of incentive requirement could come from net metering credits or avoided retail rates. Note the difference in value of MA Class I RECs varies by whether the RECs are generated during the program incentive period or after the program incentive period.
        - The MA Class I REC value included in the Task 1 modeling is assumed to be \$5/MWh after a 10- or 20-year incentive expires, so as to conservatively account for a *financier's* perspective regarding the uncertainty of financing on the basis of future REC streams.
        - For Task 2 we assume the MA Class I REC avoided value to *ratepayers* during the incentive period is assumed to be used in the 'expected' value of the avoided Class I purchase– and uses a forecast derived from public sources (see Section 4.1.3.6 for full details).
- For simplicity, the new PV program is assumed to commence starting January 1, 2017 (although in practice a new policy is likely to commence at a later date).

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[20] SEA recognizes that in practice, revenue from the FCM could be monetized by all, none, or some projects. However, for simplicity, the analysis assumes none of the projects monetize FCM revenue. While this likely overstates the absolute scale of the incentive, it facilitates the apples-to-apples comparison of policy alternatives.

- The analysis assumes retail rate structure in place at the time of this analysis. No minimum bill or other change from the proportion of utility revenue that derives from energy vs. non-energy (demand and monthly access charges) is assumed.
- Federal incentives remain as currently structured (e.g., the ITC would phase down per current law).

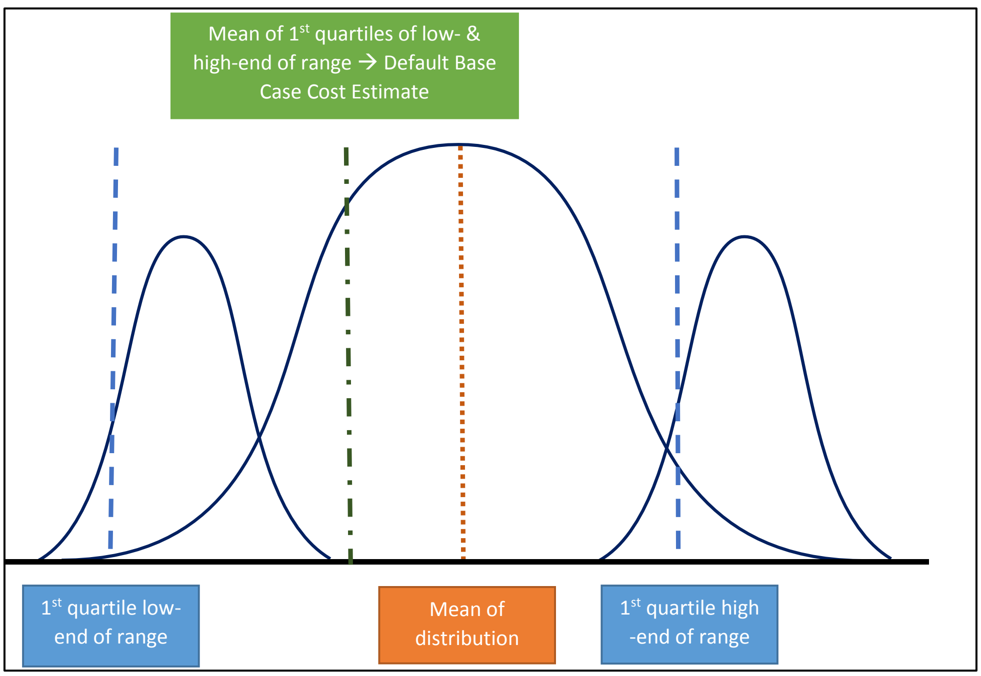
3.1.4.3 *Installed Cost Assumptions*

As a default, using the same raw survey data that were used to display project size/market sector means in Table 7 through Table 11, SEA set the base case costs for each project size/market sector combination by the following steps:

- Calculate the 1st quartile of the low-end of the range
- Calculate the 1st quartile of the high-end of the range
- Calculate the mean of 1st quartile of the low-end of the range and the 1st quartile of the high-end of the range. This is used as the default base cost estimate.

We decided to use the survey reported 1st quartiles to set defaults base costs (rather than means or medians of the survey responses) because we were concerned with sample bias (i.e., respondents were primarily market participants whose own self-interest coincided with higher reported costs that could result in higher policy incentives). Figure 12 displays a schematic of the distribution of the reported costs, and the resultant default base cost used as input to cost assumptions.

Figure 12 – Schematic of Distribution of Cost Estimates and Calculation Default Base Cost Estimate



The default base costs were then reviewed for sufficient sample size, credibility, and consistency with other project size/market sector responses. As felt necessary, the default base costs were adjusted, resulting in base costs used as inputs to the balance of the analysis. These base costs are displayed in Table 15.

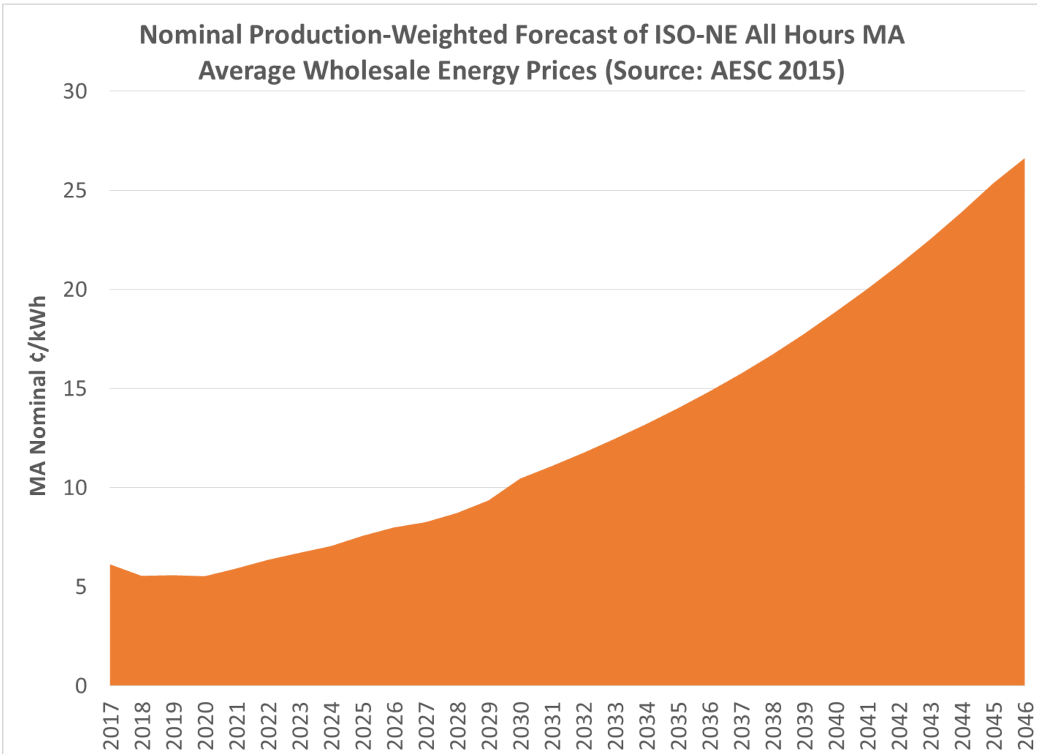
Table 15 – Starting Installed Capital Cost Estimates by Cost Trajectory

Project Type	Modeled Size (kW_{DC})	2016 Installed Capital Cost Estimate ($/$kW_{DC}$)		
		Base Cost	Low Cost	High Cost
Medium Cost Residential Roof Mount	7	$3,675	$3,308	$4,043
Low Cost Residential Roof Mount	7	$2,850	$2,565	$3,135
High Cost Residential Roof Mount	7	$4,500	$4,050	$4,950
Medium Cost Small Commercial Roof Mount	15	$3,675	$3,308	$4,043
Low Cost Small Commercial Roof Mount	15	$2,850	$2,565	$3,135
High Cost Small Commercial Roof Mount	15	$4,500	$4,050	$4,950
Commercial Lot Canopy	100	$3,625	$3,263	$3,988
Campus Lot Canopy	1000	$3,100	$2,790	$3,410
Medium Cost Community Shared Solar	1000	$2,519	$2,267	$2,771
Low Cost Community Shared Solar	1000	$2,150	$1,935	$2,365
High Cost Community Shared Solar	1000	$2,888	$2,599	$3,176
On-Site LIH	100	$2,719	$2,447	$2,991
Medium Cost VNM LIH	1000	$2,506	$2,256	$2,757
Low Cost VNM LIH	1000	$2,163	$1,946	$2,379
High Cost VNM LIH	1000	$2,850	$2,565	$3,135
Small Building Mounted	100	$2,719	$2,447	$2,991
Medium Building Mounted	500	$2,325	$2,093	$2,558
Large Building Mounted	1000	$2,100	$1,890	$2,310
Medium Ground Mount BTM	500	$2,363	$2,126	$2,599
Large Ground Mount BTM	2000	$2,150	$1,935	$2,365
Small Landfill	500	$2,594	$2,334	$2,853
Medium Landfill	1000	$2,594	$2,334	$2,853
Large Landfill	4000	$2,550	$2,295	$2,805
Small Brownfield	500	$2,550	$2,295	$2,805
Medium Brownfield	1000	$2,550	$2,295	$2,805
Large Brownfield	4000	$2,438	$2,194	$2,681
Medium Ground Mount VNM	500	$2,363	$2,126	$2,599
Medium Cost Medium Ground Mount	1000	$2,150	$1,935	$2,365
Low Cost Medium Ground Mount	1000	$1,950	$1,755	$2,145
High Cost Medium Ground Mount	1000	$2,350	$2,115	$2,585
Medium Cost Large Ground Mount	4000	$2,150	$1,935	$2,365
Low Cost Large Ground Mount	4000	$1,950	$1,755	$2,145
High Cost Large Ground Mount	4000	$2,350	$2,115	$2,585

3.1.4.4 *Wholesale Energy Revenues*

Wholesale energy market value was based on a solar PV production-weighting of hourly energy prices during a base year of 2016. The projected wholesale energy market value was trended into the future from the base year using the year-over-year trajectory of Massachusetts wholesale energy prices from the Avoided Energy Supply Costs in New England: 2015 Report (Hornby, et al., 2015). Figure 13 thus represents a production-weighted value of hourly locational marginal prices (LMPs) with the future trend of LMPs per the Massachusetts forecast in the AESC report.

Figure 13: Trend of Assumed Wholesale Energy Revenue



3.1.4.4.1 Caveat Regarding Wholesale Energy Value and Wholesale Energy Market Value

Wholesale market impacts of solar PV can be separated from the market impact on wholesale energy market prices, which is often referred to as a demand reduction-induced price effects ("DRIPE"), which involves forecasting reductions in wholesale market clearing prices over time. However, these DRIPE values are indirect benefits accruing to ratepayers, and thus are beyond the scope of a net direct ratepayer cost analysis such as this one. Furthermore, to the degree that injection of additional solar PV into the market (beyond the amount assumed in the AESC 2015 study may reduce wholesale energy prices, the impact of any such reduced revenue on required incentives is not reflected here. As ISO-NE expects capacity prices to rise in concert with reduced energy prices resulting from greater solar PV penetration (ISO New England, 2016), ignoring this increased capacity value offsets (at least directionally) the impact of ignoring the price suppression effects. In any event, these impacts are second-order and are not expected to differ in any material way between policy futures.

3.1.4.5 *Federal Tax Incentives*

On December 18, 2015, President Obama signed the Consolidated Appropriations Act of 2016 (Consolidated Appropriations Act, 2016 (H.R.2029), 2015). The Act made substantial changes to the tax law pertaining to renewable energy tax credits, including:

- An extension of the existing 30% income tax credit (ITC) for solar producers (both individual and corporate) from the end of 2016 to the end of 2019, followed by a phase-down to 26% in 2020, and 22% in 2021, before reverting to the long-term statutory levels of 10% for corporate taxpayers, and 0% for individuals;
- An allowance that taxpayers utilizing the credits may claim credit values based on the year in which the system "commenced construction", subject to the limitation that commercial operation or equivalent safe harbor must occur within 4 years of commencement of construction and that in any event such credit values must be claimed by January 1, 2024 (Internal Revenue Service, 2016).

Table 16 shows the phase down schedule for the ITC for individual and corporate taxpayers.

SEA modeled applicable federal tax credits currently in effect (subject to the limited exceptions relating to “construction lag” described in Section 6.5). For both commercial and residential systems, SEA assumed that an ITC equal to 30% of qualifying costs is available for projects entering construction on or before December 31, 2019, with the above described phase-down thereafter.

While the IRS recently issued guidance (Internal Revenue Service, 2016) allowing generators to claim the indicated incentive up to four years after commencing construction or the safe harbor equivalent, SEA assumes for simplicity in this analysis that construction and commercial operation occurred in the same calendar year. To the extent that projects actually take advantage of this ruling by qualifying for the higher level of ITC associated with the commence construction year and coming online later within the allowed timeframe, this simplification will overstate policy costs in Task 2 for all policy futures for the two to four years following December 31, 2021.

Table 16 – Changes to Federal ITC in Consolidated Appropriations Act of 2016

Year	*ITC (Individual)*		*ITC (Corporate)*	
	Pre-Omnibus	*Post-Omnibus*	*Pre-Omnibus*	*Post-Omnibus*
2015	30%	30%	30%	30%
2016	30%	30%	30%	30%
2017	0%	***30%***	10%	***30%***
2018	0%	***30%***	10%	***30%***
2019	0%	***30%***	10%	***30%***
2020	0%	***26%***	10%	***26%***
2021	0%	***22%***	10%	***22%***
2022 and Thereafter	0%	0%	10%	10%
NOTE: Applicable percentages in individual years between 2017-2021 can apply in future years if construction is commenced prior to the end of the year in question. However, the cutoff for claiming credits under "commence construction" approach is January 1, 2024.				

In addition to tax credits, federal energy policy also affords renewable energy systems access to depreciation allowances, including both bonus and accelerated depreciation. In addition to the Appropriations Act, on December 18, 2015, President Obama also signed the Protecting Americans from Tax Hikes Act of 2015 ("PATH Act").[21] The PATH Act made several changes to depreciation allowances available to solar PV system owners that are also corporate taxpayers, including:

- Permits use of 50% bonus depreciation retroactively through tax year 2015 (previous authorization had allowed it through 2014 only);
- Extends 50% bonus depreciation through tax years 2016 and 2017;
- Steps down bonus depreciation in to 40% in 2018), to 30% in 2019, and eliminates it altogether in 2020; and
- Allows a business taxpayer (under circumstances in which the alternative minimum tax (AMT) applies) to elect AMT credits in lieu of bonus depreciation.

In addition to bonus depreciation, modeling also took into account the standard depreciation allowances, to which no expiration date applies. The majority of capitalized system costs qualify for five year depreciation under the Modified Accelerated Cost Recovery System (MACRS). Other accelerated and straight-line classifications were also deployed to depreciate the remaining capitalized costs. Specifically, 96% of installed costs (other than those related to transmission and interconnection) were modeled as depreciated on the five-year MACRS schedule, 2% of installed costs were depreciated on the 15-year MACRS schedule, and 2% of installed costs were depreciated on a 20-year straight-line basis. Transmission and interconnection costs were depreciated using the 15-year MACRS schedule. SEA assumed that bonus depreciation is available on the above-described phase-out schedule, with the

[21] The Consolidated Appropriations Act of 2016 was amended to include the PATH Act, and both are now part of Public Law (P.L.) 114-113.

remaining depreciable costs treated – on a percentage basis – as outlined here. Residential systems owned by private third-parties and operated under Power Purchase Agreements (PPA) or leased to the homeowner qualify for all federal incentives available to commercial systems. Homeowner-owned residential systems qualify for the ITC, as well as Massachusetts' $1,000 residential PV tax credit, but do not qualify for depreciation benefits.

Finally, this analysis assumes that project investors are able to make efficient use of both types of federal tax incentives. As a practical matter, however, some investors may not be able to fully utilize both the ITC and depreciation during the periods in which these incentives are available.

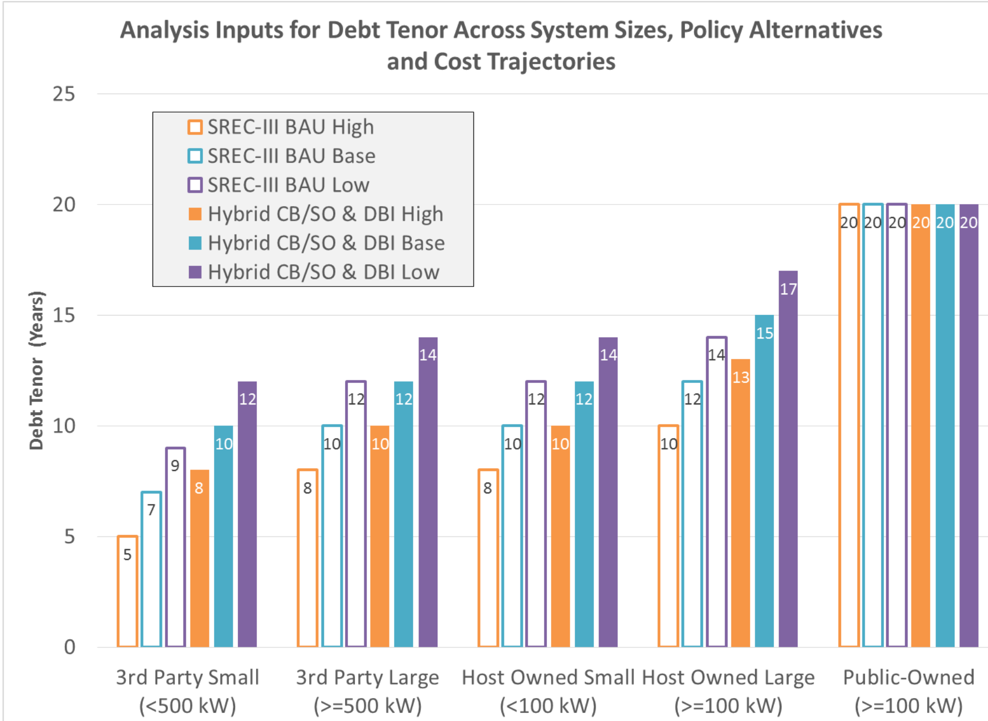
3.1.4.6 *Financing Assumptions*

This analysis conducts a cost-based review of the revenue required for a range of solar project size categories and ownership structures to cover their expenses and realize a specified target threshold return on invested capital. The assumptions included and referred to herein are based on consideration of market participant survey responses, additional market research, comparable programs in other states, supplemental interviews, and the analysis team's industry experience. This section provides a summary of the rationale for the financing assumptions deployed in this analysis.

3.1.4.6.1 Debt Assumptions

The investment terms for solar energy are often project-specific. This is particularly true for debt. For third-party-owned facilities, the lending assumptions are intended as a proxy for either a project finance-based approach (with debt at the project level) or a group of projects with debt applied at the portfolio level or through another means of back leverage. A sustainable loan amount is typically derived through the discounting of contracted cash flow available for debt service and a specified debt service coverage ratio.

Figure 14 – Debt Tenor Inputs by Policy Alternative, System Size Threshold and Cost Trajectory



The debt tenor (or term, as shown in Figure 15 above) is typically based on contracted revenue and market conditions. In some cases, amortization schedules are longer than repayment periods, forcing refinancing. Such conditions are considered in the selection of assumptions but are not modeled explicitly, instead reflecting debt financing in the form of a single term loan. Interest rates are market-based, and are intended to appropriately reflect the cost of converting the market's inherent variability into a fixed rate for the full term of the loan. A lender's fee is assumed, and is modeled as a one-time payment set equal to the estimated market premium over LIBOR[22] multiplied by the loan amount.

By comparison, the debt for host-owned facilities is assumed to be 'general obligation' in nature. Homeowner loans are assumed to be from local or regional banks and rely on household income and credit.[23] Large host-owned facilities are assumed to derive debt for solar as a part of general corporate borrowing, issued for the acquisition of both a solar installation and core business property, plant and equipment. The general obligation nature of host debt is assumed to result in slightly more attractive terms, principally through a longer tenor. Public projects are assumed to be financed 100% with 20-year general obligation bonds, including a pledge of the issuing governmental entity's full faith and credit.

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[22] See the Terms Used in this Analysis section for a definition of LIBOR. For more information on the role of LIBOR in financial markets, please see the Intercontinental Exchange's LIBOR Frequently Asked Questions page, available at: https://www.theice.com/publicdocs/IBA_LIBOR_FAQ.pdf

[23] SEA does not account for the Massachusetts Solar Loan Program (SLP) in the analysis, given that at its small scale it is unlikely to materially change the average interest on term debt provided to borrowers.

Figure 15 – Debt Percentage by Year and Policy Alternative

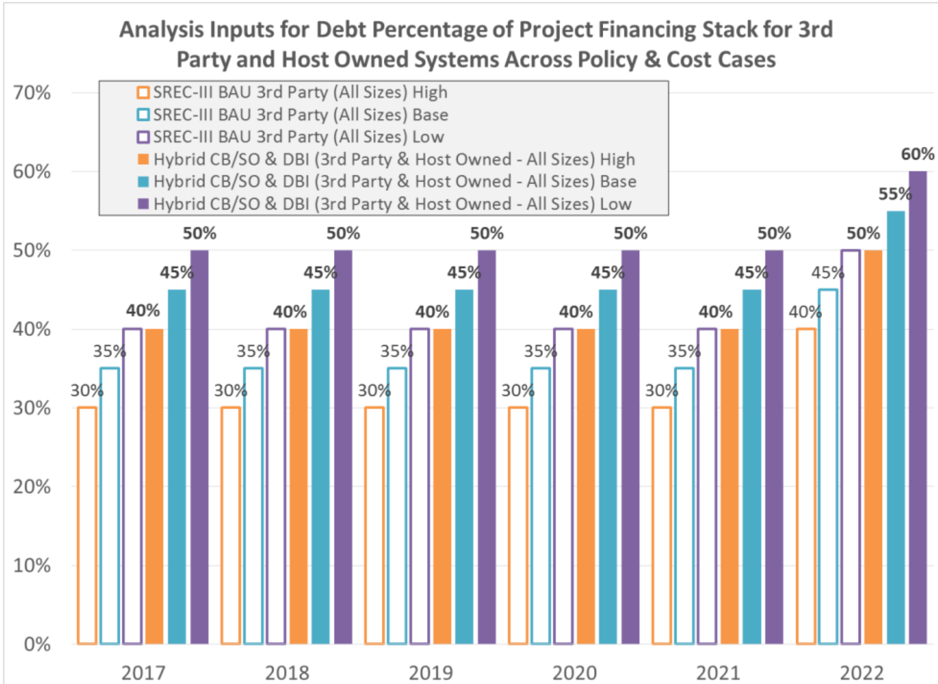


Figure 15 shows the percentage of debt in the project financing stack assumed for varying project types under different ownership structures, varying across policy cases. With the exception of public projects (which are already at 100%), the ratio of debt to total capital is assumed to increase as the ITC decreases over time.

Figure 16 – Interest on Term Debt Inputs across System Types, Policy Alternatives and Cost Cases

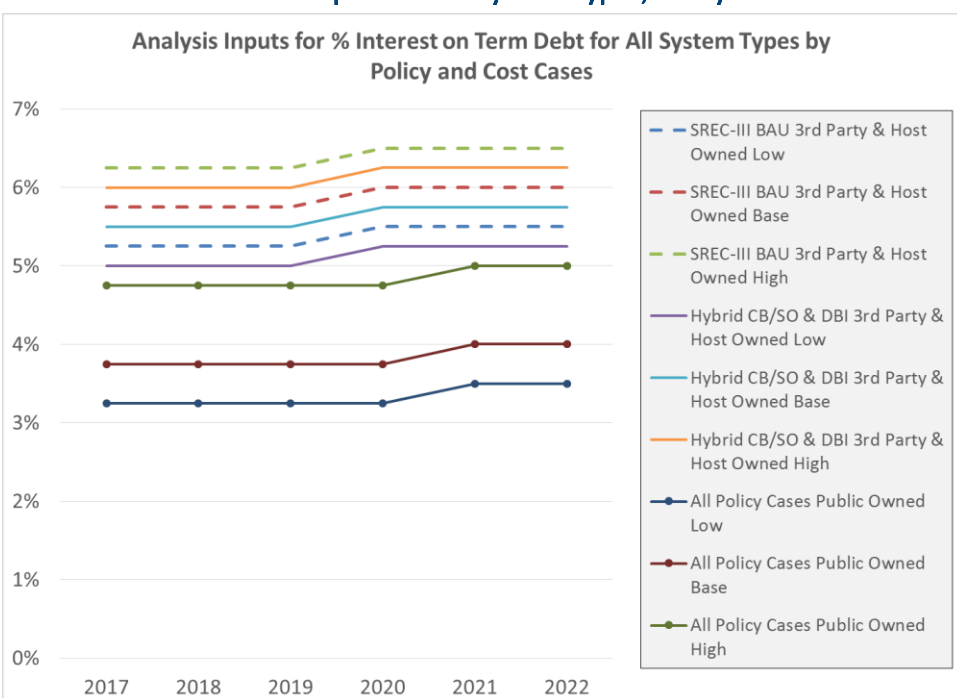


Figure 16 shows the interest rates on term debt across policy alternatives, at the time of the loan closing. Interest rates are assumed to increase by modest amounts over the analysis term, consistent with market expectations. With respect to policy differentiation, sustainable loan amounts (and therefore debt to equity ratios) are assumed to increase for policy designs that provide greater revenue certainty. Where contract durations extend to 15 or 20 years, this certainty is also expected to increase the loan tenor.

3.1.4.6.2 Equity Assumptions

For third-party equity, the assumptions included herein represent a blend of tax- and cash-motivated investors, who are assumed to make effective use of all tax benefits.[24] To this end, the blended cost of equity assumption is intended to represent an efficient market, without favoring one capital structure or business strategy over another. While ownership "flips" and other optimized structured finance approaches are expected, this analysis assumes that the equity assumptions represent the long-term requirements of all equity investors and are assumed constant for the life of the project.

As with debt, equity in the non-public host-owned model is assumed to be derived from general corporate (and individual homeowner) resources. As a result, hosts are assumed to consider the opportunity cost of alternative investments in its core business. This tends to apply upward pressure to the equity return requirements for commercial host-owned projects compared to the tax motivation and increasing competition that characterizes the third-party-owned market.

[24] If tax equity is scarce during the period of time in which ITC is in effect, this assumption could understate the revenue requirement and required incentive.

Figure 17 - Target After-Tax Equity Internal Rate of Return (IRR) Inputs for Smaller-Scale Third Party and Host Owned Systems across Policy Alternatives and Cost Cases

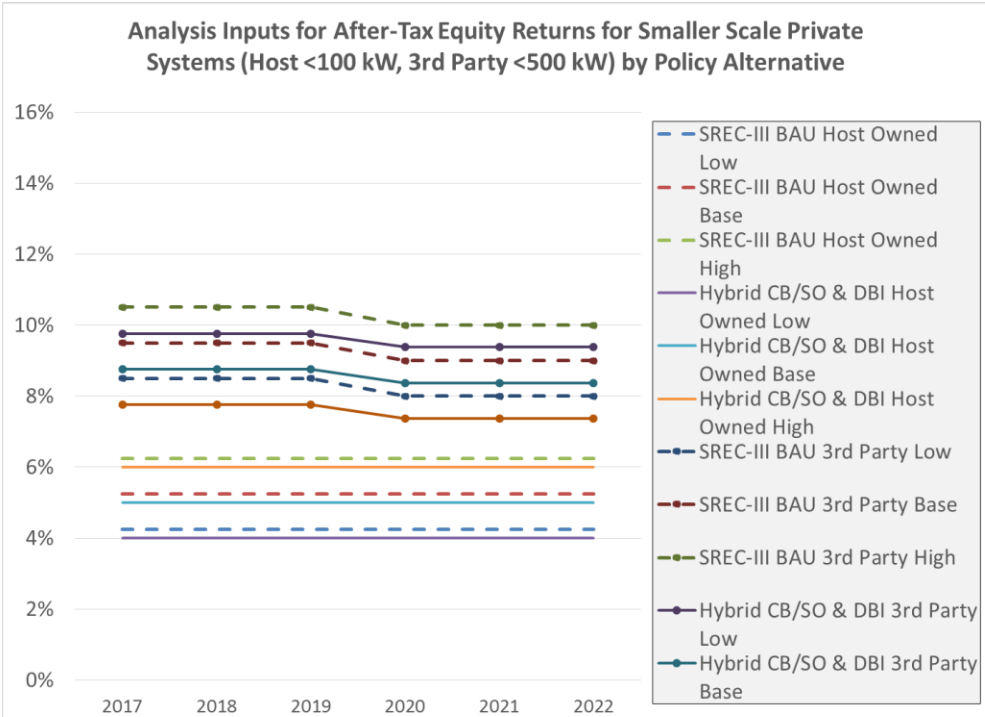


Figure 18 – Target After-Tax Equity Internal Rate of Return (IRR) Inputs for Larger-Scale Third Party and Host Owned Systems across Policy Alternatives and Cost Cases

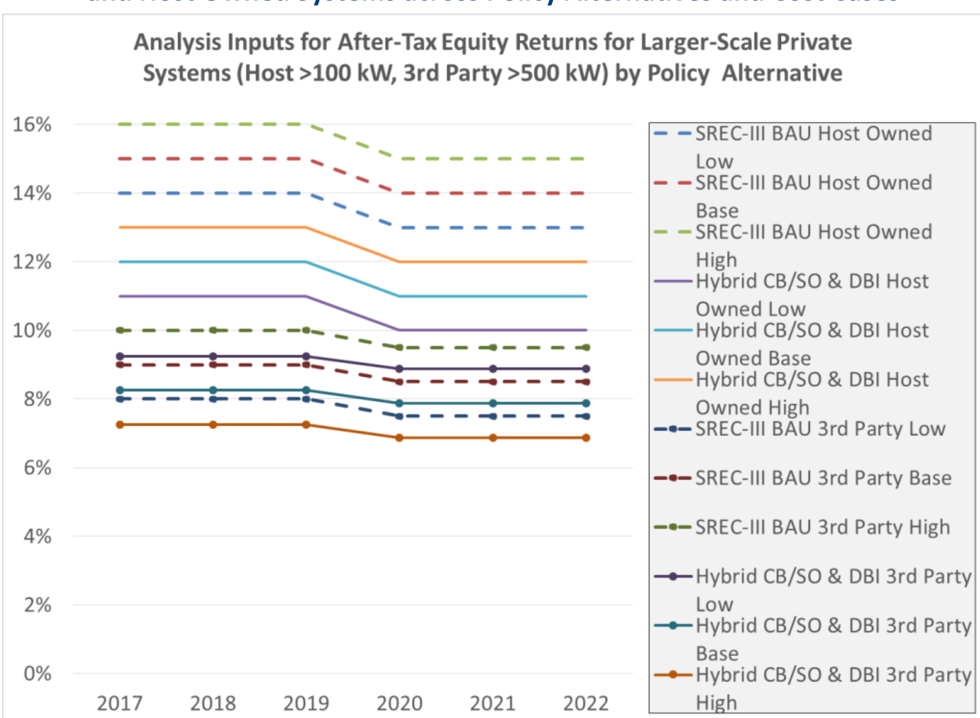


Figure 17 and Figure 18 above show the target after-tax equity internal rates of return (IRRs) for smaller- and larger-scale third party and host-owned projects. In general, increased competition among investors is expected over the analysis term. This is represented through modest downward adjustments to the assumed cost of equity over time, for both third–party-owned and host-owned projects. Where policy design provides for greater revenue certainty – as with either of the bundled contract approaches – further downward pressure on equity return requirements is expected.

3.1.4.7 *Interconnection Cost Assumptions*

To help guide our assumptions of the interconnection costs, which are modeled as separate from and additional to the other installation and ongoing costs, SEA relied on three sources:

- SEA's proprietary research and analysis;
- A sample from review of over 150 utility interconnection service agreements (ISAs) for utility side of the meter construction costs; and
- Responses to the survey discussed in Section 3.1.

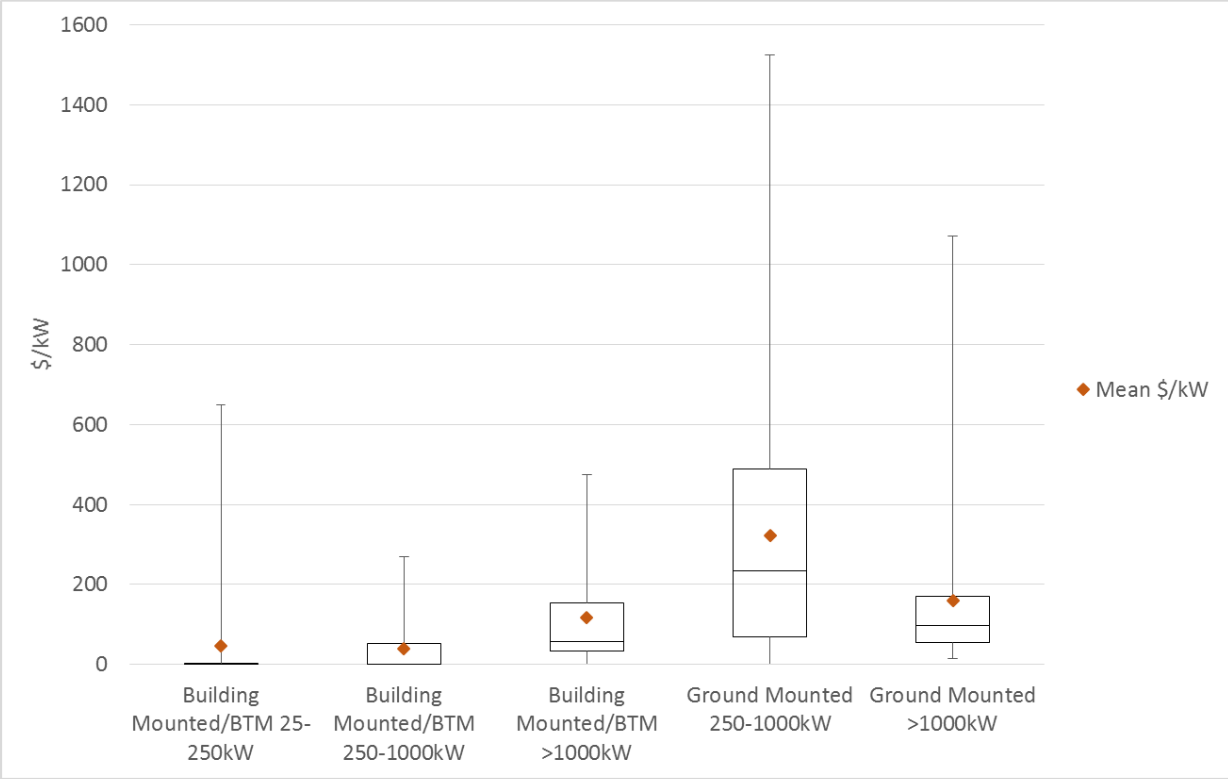
The ISA costs range from zero dollars to millions of dollars depending on the circumstances (See Table 17). The utility interconnection construction costs are a subset total of interconnection costs, but when the utility construction costs are high it can be the majority of the total interconnection costs. As high interconnection costs can kill a project, not all projects with the highest ISA costs were assumed to be built.

Table 17 – Summary Utility Interconnection Construction Cost Statistics by Project Categories

Market Sector and Size Category	Sample Size	Mean	Max	Min	Standard Deviation	Mean $/kW	Standard Deviation Cost/kW
Building Mounted/BTM 25-250kW	20	$8,030	$125,000	$0	$27,175	$47	$142
Building Mounted/BTM 250-1000kW	24	$24,946	$199,554	$0	$46,969	$41	$66
Building Mounted/BTM >1000kW	18	$272,945	$916,468	$0	$283,493	$118	$132
Ground Mounted 250-1000kW	19	$218,217	$565,000	$0	$184,587	$322	$354
Ground Mounted >1000kW	60	$561,734	$7,324,344	$48,000	$1,274,419	$159	$184
Solar Canopy 25-250kW	4	$44,650	$130,000	$0	$50,322	$237	$204
Solar Canopy 250-1000kW	5	$2,566	$12,828	$0	$5,131	$3	$6
Solar Canopy >1000kW	6	$101,759	$232,438	$0	$79,760	$54	$44

Figure 19 displays the summary statistics of utility interconnection construction costs via a Box and Whisker plot. The lines for each category represent (from the bottom up) the minimum, 1st quartile, median, 3rd quartile and maximum costs in $\$/kW_{DC}$; the mean of the category is shown as the diamond. For the Building Mounted/BTM 25-250 kW category the minimum, 1st quartile, median, 3rd quartile are $\$0/kW_{DC}$. Building Mounted/BTM projects incur lower utility construction costs as they are more likely to be proposed to be interconnected to a more robust part of the distribution system than Ground Mount projects that may be located in far-flung areas with single phase service.

Figure 19 – Box & Whisker Plot for Selected Categories of Utility Interconnection Construction Costs



In the end, the results of the ISA sample verifies that developers are seeing highly variable utility interconnection costs and in some cases, interconnection costs that are material relative to the project capital expenditure, which can typically range from \$2,000 to \$3,000/kW. As a default (and as done for installed costs excepting interconnection), SEA set the base case costs to mean of the 1st quartile of the low- end and high-end range of respondents cost self-reports. SEA adjusted the base cost assumptions using our judgement in some circumstances, as well in setting the low and high cost cases as is shown in Table 18.

Table 18 – 2016 Assumed $/kW-DC Interconnection Costs

Project Description	Modeled Project Size (kW DC)	Low Cost	Medium Cost	High Cost
Residential Roof Mount	7	$10	$29	$48
Small Commercial Roof Mount	15	$10	$29	$48
Commercial Lot Canopy	100		$151	
Campus Lot Canopy	1000		$139	
Community Shared Solar	1000	$53	$141	$230
On-Site LIH	100		$136	
Low Cost VNM LIH	1000	$53	$141	$230
Small Building Mounted	100		$128	
Medium Building Mounted	500		$95	
Large Building Mounted	1000		$95	
Medium Ground Mount BTM	500		$95	
Large Ground Mount BTM	2000		$95	
Small Landfill	500		$109	
Medium Landfill	1000		$109	
Large Landfill	4000		$114	
Small Brownfield	500		$120	
Medium Brownfield	1000		$120	
Large Brownfield	4000		$95	
Medium Ground Mount VNM	500		$133	
Medium Managed Growth	1000	$78	$133	$188
Large Managed Growth	4000	$70	$158	$245

3.1.4.8 *Installed Cost Trajectories*

3.1.4.8.1 Methodology & Data Sources

This section describes the installed cost trajectories from a national perspective, while Sections 3.1.3 and 3.1.4 above sections describe the key assumptions and approach of estimating 2016 local costs. SEA applied national cost trajectories to the 2016 base local cost estimates (shown in Table 15) in order to forecast future year local costs. SEA sought to develop an installed cost forecast based on the highest-quality and most recent independent data available from both public and non-public sources. To do so, SEA purchased the most recent full-scope analysis of solar balance-of-systems (BOS) costs completed by GTM Research (Shiao, 2015). GTM's data is broadly considered in the solar and distributed energy industries as being of the highest grade, and is frequently utilized in a wide variety of PV cost analyses undertaken by the National Renewable Energy Laboratory and Lawrence Berkeley National Laboratory (Feldman et al., 2015). SEA also supplemented this forecast with forward cost projections from the National Renewable Energy Laboratory 2015 Annual Technology Baselines (NREL ATB) report (National

Renewable Energy Laboratory, 2015), another industry standard source of long-term solar PV price projections for larger-scale systems.[25]

To develop a base trajectory cost case, SEA trended the national installed cost projections developed by GTM Research through 2020 and the medium cost case used in the NREL 2015 ATB from 2021 through 2025 by using a compound annual rate of decline from 2016-2025 to smooth the forward cost curve.[26] The formula for estimating compound annual decline in PV prices can be stated as:

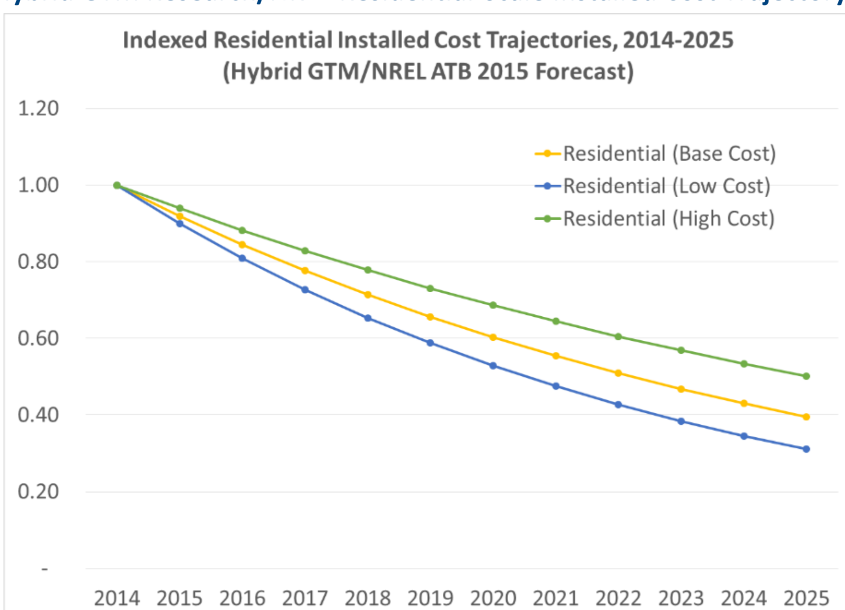
$$Compound\ Annual\ Decline\ \% = \left(\left(\frac{PV\ Cost_{Ending\ Value}}{PV\ Cost_{Starting\ Value}} \right)^{1-Total\ Periods} \right) - 100\%$$

High and low cost trajectories were developed by varying the annual rate of change in the base case by +/- 2% per year, consistent with the distribution of high and low forecasts in other analyses reviewed.

3.1.4.8.2 Cost Trajectories for Residential, Commercial & Utility-Scale Systems:

Using the data sources described above, SEA developed base, high and low cost trends for residential scale (15 kW and below), commercial-scale (15 kW to 1 MW) and utility-scale (>1 MW). These trajectories are shown in Figure 20, Figure 21 and Figure 22 below, respectively, and reflect nominal values. These trends were applied to the base local initial values.

Figure 20: Hybrid GTM Research/NREL Residential-Scale Installed Cost Trajectory, 2014-2025



[25] NREL recently posted a discussion draft of its 2016 ATB draft results here: http://www.nrel.gov/analysis/data_tech_baseline.html

[26] In all cases, SEA assumed the cost trajectories for fixed-axis systems.

Figure 21: Hybrid GTM Research/NREL Commercial Installed Cost Trajectory, 2014-2025

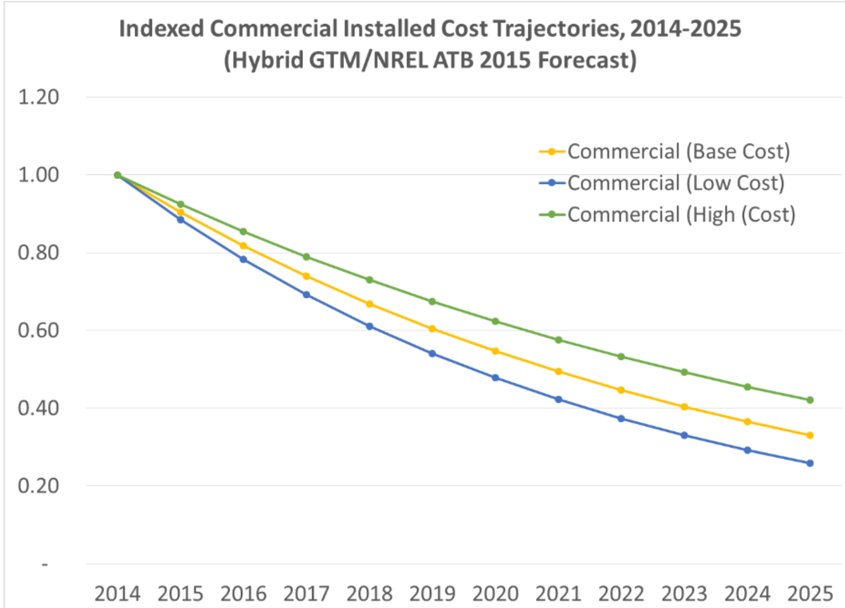
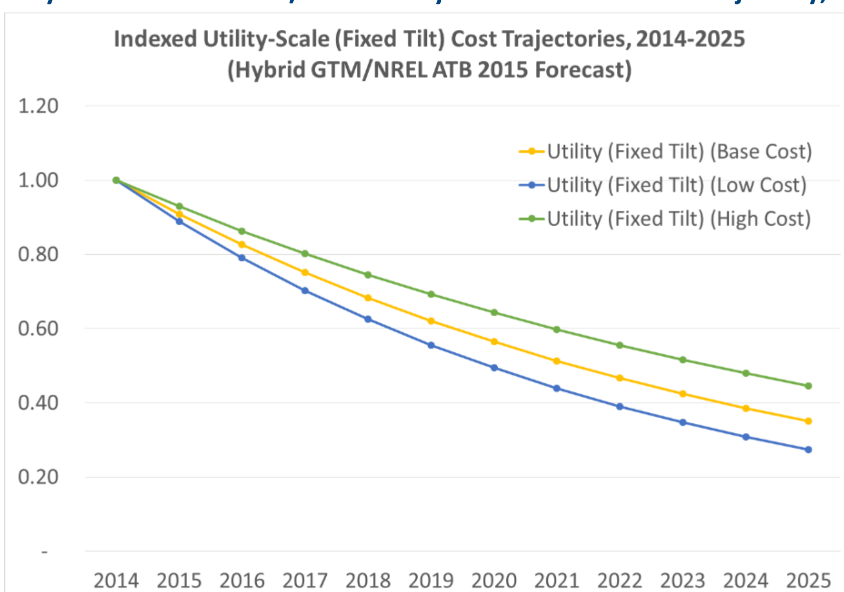


Figure 22: Hybrid GTM Research/NREL Utility-Scale Installed Cost Trajectory, 2014-2025



Between 2014 and 2025, SEA's hybrid GTM Research and NREL forecast suggests a compound annual decline rate of 8.1% for all residential-scale base cost cases, 9.6% for commercial-scale systems and 9.1% for utility scale systems on an inflation-adjusted 2016 basis. Each trajectory includes a +/- 2% variance for low and high cost cases. As a result, these trajectories result in installed cost declines between 2014 and 2025 of between 50% to 69% for residential-scale systems, 58% to 74% for commercial scale systems and 55% to 73% for utility-scale systems.

3.2 Selected Task I Results: Solar PV System Cost Analysis Results & Key Drivers

This section outlines the differences in revenue requirements for selected systems derived from the analysis of data obtained (and transformed) as a result of the stakeholder survey described in Section3.1. Also shown are a limited number of "effective incentive" requirement results in order to illustrate differences in unit costs (in $/MWh) of 10- and 20-year incentives across policy alternatives. To see the "effective incentive" requirements for each system type, along with the remaining revenue requirement results, please see attached files[27]. Overall, the following factors most strongly influence the overall revenue requirement for each affected system type:

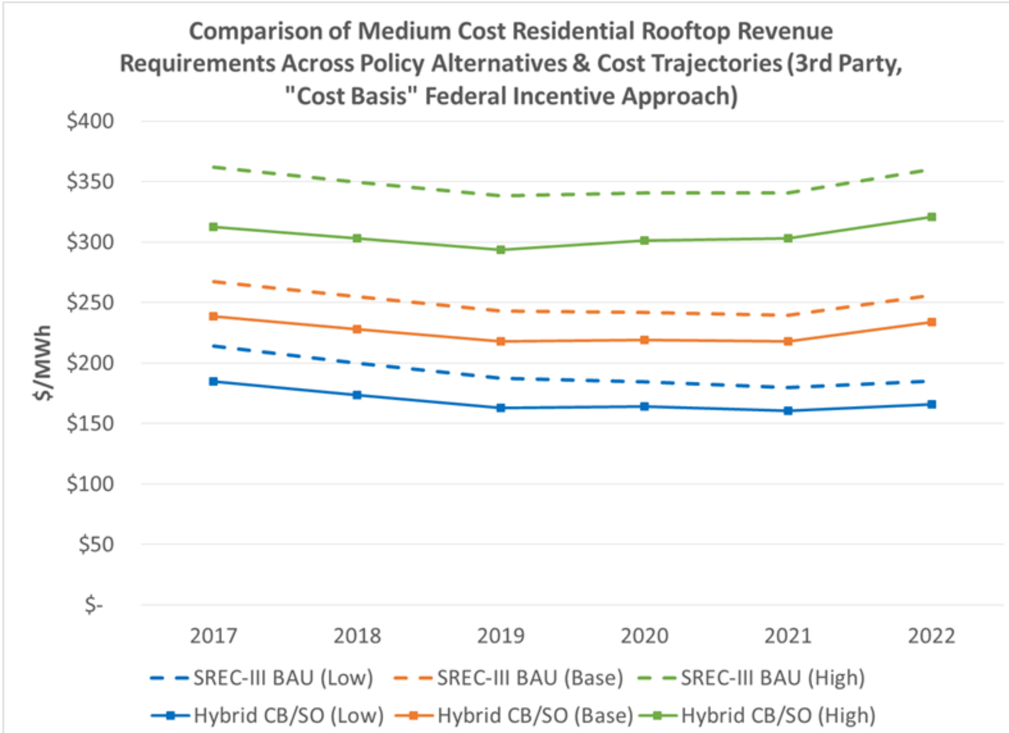
- The size of the system;
- Cost differences between identical system types;
- The policy alternative under consideration (due to differences in the risk to debt and equity investors of earning a market return);
- The expiration of the ITC in 2022 & expiration of bonus depreciation in 2020; and
- The approach taken by a developer to monetize all federal tax benefits (including MACRS depreciation, bonus depreciation and the ITC).

3.2.1 Differences in Policy Alternatives

As discussed in some detail above, the relative reduction in the cost of capital associated with the "bundled" non-SREC alternative programs also reduces total system costs and revenue requirements by reducing investor risk. Figure 23 shows how this phenomena manifests itself in terms of the average revenue requirement for an illustrative medium cost residential roof mount systems. The relative impact between policy alternatives is, in general, directionally similar across all project types. Under an SREC-III BAU future, the overall revenue requirement is 10%-12% higher than for the same system under both non-SREC "bundled" Hybrid Competitive Bid/Standard Offer and Declining Block Incentive options (depending on whether a low, base or high cost trajectory is used). Furthermore, while it is possible to discern significant cost reductions from 2017 and 2020 in both cases, the overall levelized revenue requirement remains relatively flat (or, in some cases when using the "cost basis" approach) goes up slightly relative to 2020 values, which can be traced to federal incentives being reduced (or expiring) under current law.

[27] "Final Task I Effective Incentive Requirement Results_662016.xlsx" and "Final Task I Revenue Requirement Results_662016.xlsx"

Figure 23: Comparing Revenue Requirements for Medium Cost Residential Roof Mount under SREC-III BAU and Bundled Purchase Policy Alternatives



3.2.1.1 *Impact of "Dry Hole" Costs in Hybrid CB/SO Policy Alternative*

Developers bidding into the competitive bid portion of a market must incur in aggregate 1.5 "dry holes" for every successful project; 'dry hole' cost represents additional overhead compared to an open incentive program in which developers must make one sale per development / PPA contract. These 'dry hole' costs are more appropriately included in Task 1 as they add to incentives required by developers to participate in a market. Nonetheless we have included the 'dry hole' costs as part of Task 2 for:

- Modeling simplicity;
- Consistency with the approach taken in the Net Metering & Solar Task Force (NM&STF) report (Grace, et al., 2015); and,
- Ease in visualizing the negligible effects of 'dry hole' costs compared to other ratepayer impacts.

Due to the fact that SEA has added in the impact of administrative costs in the Task 2 ratepayer cost analysis rather than under Task 1 (which is described in greater depth in the Task 2 section of this report) the graphic above does not directly account for the added levelized system and incentive costs associated with the Hybrid CB/SO policy alternative that are unique to a structure based on competitive bidding. However, these costs, as applied to all systems greater than 250 kW DC, are too small on a unitized $/MWh basis to include in the charts in any kind of clear or recognizable way. Thus, Table 19 below illustrates these "dry hole" costs (which are described in greater depth in the description of Task 2, see Section 4.1.3), which slightly inflate the unit value of the revenue requirement for a medium cost residential roof-mounted system under the Hybrid CB/SO policy alternative relative to the DBI alternative.

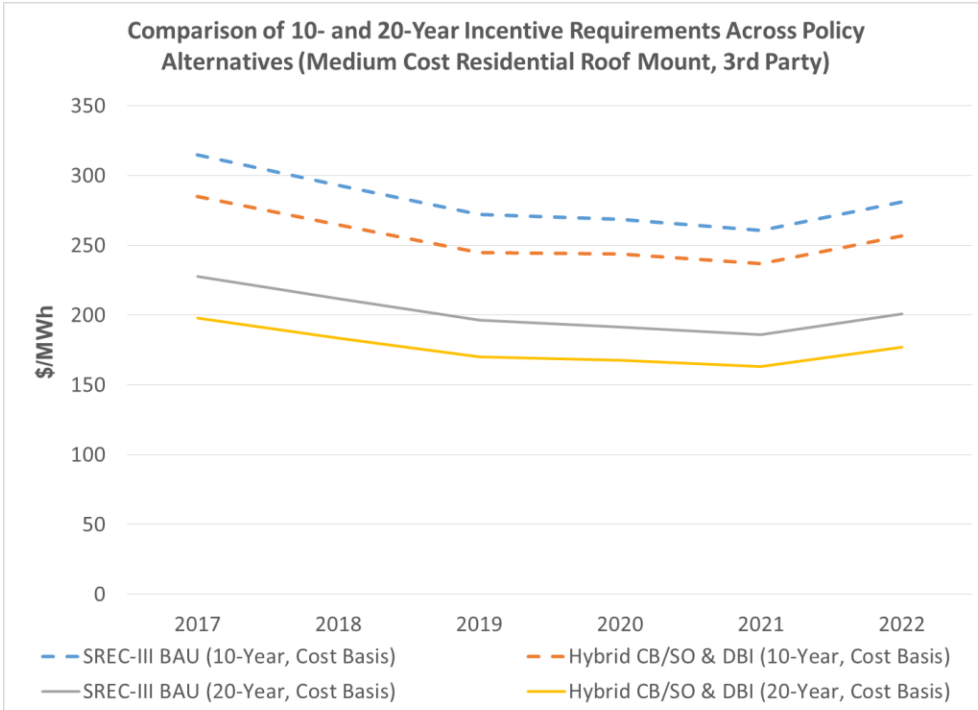
Table 19 – Illustration of “Dry Hole” Developer Cost in Modeled Hybrid CB/SO Policy Alternative (Medium Cost Residential Roof Mount, 3rd Party, “Cost Basis” Federal Incentive Approach)

Year	*2017*	*2018*	*2019*	*2020*	*2021*	*2022*
Incremental Capacity Exceeding 250 kW DC (MW_{DC})	168.1	167.3	166.4	165.6	164.8	163.9
Developer Overhead "Dry Hole" Cost ($\$/kW_{DC}$)	$81	$82	$84	$85	$86	$88
Market-Wide Developer Overhead "Dry Hole" Cost	$13.6 Million	$13.8 Million	$13.9 Million	$14.1 Million	$ 14.2 Million	$14.4 Million
Total Lifetime Generation of Systems >250 kW DC (MWh)	4,876,580	4,876,184	4,877,261	4,875,655	4,871,595	4,749,365
Levelized "Dry Hole" Cost/MWh	***$2.80***	***$2.82***	***$2.85***	***$2.89***	***$2.92***	***$3.03***

3.2.1.2 *Duration of Incentives*

In addition, the choice of incentive duration has a significant impact on the levelized unit values of incentives offered to solar generators. Some stakeholders have advocated for one policy future over another based on comparisons of per-MWh inventive levels among policies of different durations, which can be quite misleading. In addition, stakeholders sometimes conflate the 10- or 20-year incentive value with a 25-year system revenue requirement (the typical metric for determining a system’s relative cost to other non-dispatchable renewable resources).

Figure 24 – Comparing 10- and 20-Year Incentive Requirements for Residential Roof Mounted Systems across Policy Alternatives



To illustrate, Figure 24 shows the differences in incentive requirements for the same residential roof mounted third-party owned system under 10- and 20-year incentive durations. As the graph shows, if DOER were to elect a 20-year incentive framework over a 10-year framework, the per unit value of the levelized incentive paid to generators would be significantly lower, but not half that of a 10-year incentive. The narrative will return to the 10 vs. 20 year incentive duration issue in regards to net ratepayer impacts in Section 4.2.3.

3.2.1.3 *Approach to Taxation*

In addition, SEA observes that the property taxes assessed on solar PV systems between states (and between localities in a given state) can explain some differences between the costs of third-party- and host-owned systems. For example, while host owners of systems under Rhode Island's Renewable Energy Growth program (a hybrid competitive bid and fixed-price contract program) receive higher incentives than third-party system owners, host owners must pay income tax on the net excess generation that results in billing credits[28], as well as property tax[29]. However, in Massachusetts, all generation is treated as either used on-site or as a net metering credit carried forward to offset future monthly balances, and thus not subject to state or federal income tax, which commonly results in a higher required incentive for third-party-owned systems in Massachusetts.

[28] The energy consumed on-site in Rhode Island is not subject to state income tax.

[29] Massachusetts has a 20-year property tax exemption for "any solar or wind powered system or device which is being utilized as a primary or auxiliary power system for the purpose of heating or otherwise supplying the energy needs of property taxable" under M.G.L. Chapter 59.

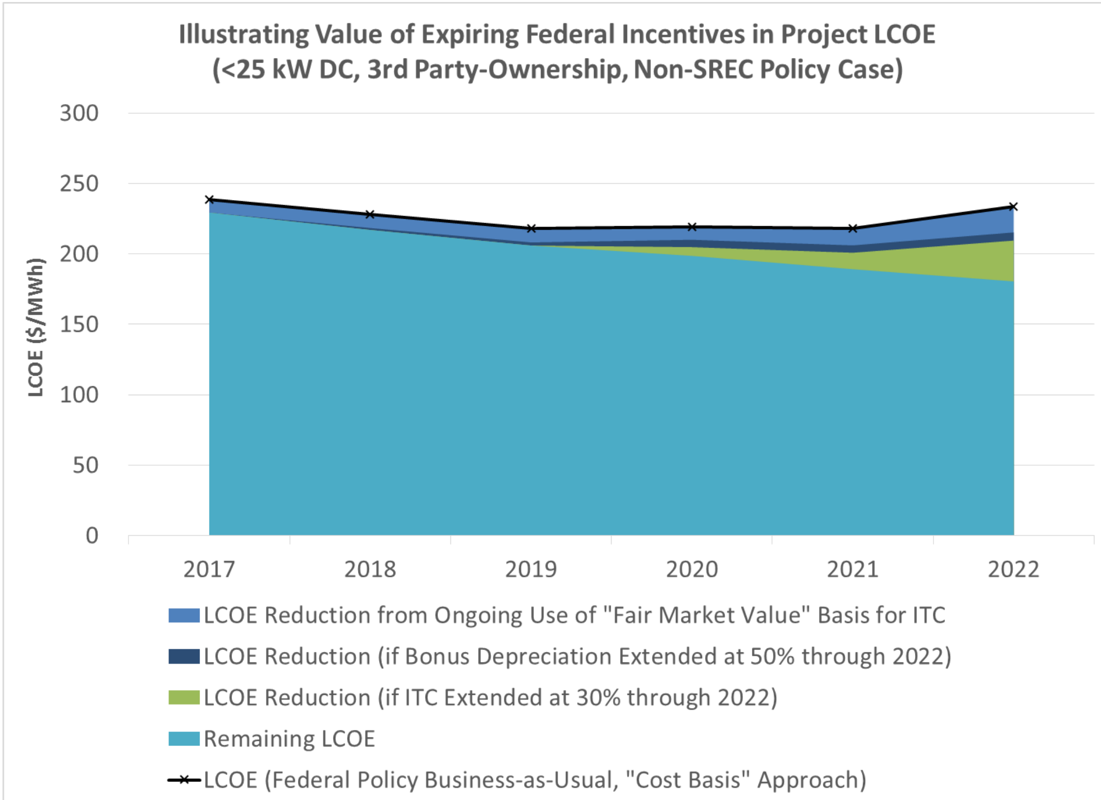
3.2.2 Federal Policy Trajectories and Varying Monetization Approaches to Federal Tax Incentives

One of the more compelling aspects of this analysis is the degree to which levelized revenue requirements do not decline over time at a rate that closely resembles the underlying decline in system installed costs. While it is possible to trace this, in part, to increasing costs of interconnection and O&M, the most significant contributor to this relative stagnation in revenue requirements is the expiration (under current law) of the ITC in 2022 and bonus depreciation in 2020. Furthermore, the manner in which developers choose to monetize available federal tax benefits plays a key role in determining the relative competitiveness of host- and third party-owned systems. While all third party and host-owned system equity investors can choose to utilize the federal tax benefits described above on the basis of the system's underlying cost (referred herein as the "cost basis" approach), third party system owners can choose under current tax law to monetize their tax benefits based on the system's "fair market value".

Using the "fair market value" approach can make a significant difference in terms of overall revenue and incentive requirement. It is in the interest of system owners (particularly large national players with low cost structures) to claim "fair market value" (e.g., as a result of a sale, or as backed by a PPA) when they can justify a it as higher than its actual direct cost, and thus provides a larger value against which the ITC and depreciation can be claimed.[30] To determine the exact value of these federal incentives in aggregate (and approaches to monetizing them) in terms of reduced levelized revenue requirement, SEA calculated the change in LCOE associated with extending these federal incentives at 2017 levels for a third party-owned <25 kW DC system. For each supplementary run, SEA recalculated different LCOEs under different federal policy futures (e.g., if the ITC were to remain at 30%, bonus depreciation at 50%, and the IRS continues to permit monetization of these tax benefits based on the system's "fair market value").

[30] For example, many system owners reason that they should be able to claim the ITC and depreciation on the basis of the price they paid for their system in the marketplace, not in terms of its underlying costs, and thus claim the ITC and depreciation on a "fair market value" basis. For more detail regarding how the "fair market value" basis affects underlying system economics (especially for residential systems), please see Bolinger & Holt, 2015.

Figure 25 - Levelized Cost Value of Expiring (or Potentially Expiring) Federal Incentives (Medium Cost <25 kW DC Systems under a Base Cost Trajectory, 3rd Party)



Overall, Figure 25 shows that the impact of the expiration of these federal incentives largely explains the overall difference between LCOE and installed capital cost trajectories. While a full extension of all expiring federal incentives (and retention or continued use of the "fair market value" approach [31]) would allow revenue requirements to fall 18%, allowing the ITC and bonus depreciation to expire under current law (and assuming "fair market value" is not a viable future option for third party developers) results in only a 2% overall reduction between 2017 and 2022, with costs increasing between 2020 and 2022.

[31] When third-party developers choose the "fair market value" approach, they are able to claim the ITC on a basis that exceeds the system's installed cost. To date, this has been a common approach for some installers choosing to do business in Massachusetts, but not others. However, the approach has been the subject of enhanced scrutiny by the Treasury Department's Inspector General for Tax Administration since 2012, which has not (to date) concluded its investigation (Bolinger & Holt, 2015). For the purposes of this analysis, SEA has conducted Task 1 and Task 2 sensitivities that account for these differences, in which it is assumed that either 1) all third party and host-owned projects monetizing the ITC use the "cost basis" approach or 2) that all third-party owned projects monetize the ITC using the "fair market value" approach, while host-owned projects do not.

3.2.3 System Size Differences

Larger-scale solar PV systems tend to enjoy economies of scale and as a result, lower unit costs (National Renewable Energy Laboratory, 2015). These differences in scale continue to play a significant role in differentiating systems from one another.

Table 20 and Table 21 compare the average revenue requirement of medium-cost small commercial and residential roof-mounted systems with the average requirement for a medium-scale (500 kW_{DC}) building-mounted system (both of which use the "cost basis" approach for valuing federal incentives). Overall costs of the 500 kW_{DC} medium commercial building-mounted system under different installed capital cost trajectories are decidedly smaller than for a medium-cost residential/small commercial system (<= 25 kW DC), which are more pronounced as a result of the differences in unit costs.

Table 20 - Average Revenue Requirement of Medium Cost Residential/Small Commercial Rooftop Systems under Low, Base and High Cost Trajectories (Third Party-Owned)

Medium Cost Rooftop Solar (<=25 kW) (SREC-III BAU 10-Year, Third Party-Owned, Cost Basis, $/MWh)						
Installed Capital Cost Trajectory	2017	2018	2019	2020	2021	2022
Low	$214	$200	$187	$184	$180	$185
Base	$268	$255	$243	$242	$239	$256
High	$362	$350	$338	$340	$341	$360

Table 21 - Average Revenue Requirement of Medium Building Mounted (500 kW DC) Rooftop Systems under Low, Base and High Cost Trajectories (Third Party-Owned)

Rooftop Solar (500 kW) (SREC-III BAU 10-Year, Third Party-Owned, Cost Basis, $/MWh)						
Installed Capital Cost Trajectory	2017	2018	2019	2020	2021	2022
Low	$150	$140	$132	$130	$127	$129
Base	$190	$181	$172	$171	$168	$172
High	$242	$234	$226	$226	$225	$233

3.2.4 Cost Differences between Identical System Types

Another key revenue requirement differentiator is the variation in costs associated with higher and lower-cost versions of the same system. As shown in Table 22 and Table 23 below, the differences in average revenue requirement between high and low-cost 1 MW_{DC} virtually net metered (VNM) systems intended for consumption by low-income customers is nearly $100/MWh in all cases.

Table 22 - High Cost VNM Low-Income Solar PV Average Revenue Requirement under Low, Base and High Cost Installed Capital Cost Trajectories (Third Party-Owned)

High Cost Community Shared Solar (1 MW) (SREC-III BAU 10-Year, Third Party-Owned, Cost Basis, $/MWh)						
Installed Capital Cost Trajectory	2017	2018	2019	2020	2021	2022
Low	$205	$195	$186	$184	$181	$183
Base	$259	$249	$240	$239	$237	$242
High	$332	$324	$316	$318	$318	$329

Table 23 - Low Cost VNM Low-Income Solar PV Average Revenue Requirement under Low, Base and High Cost Installed Capital Cost Trajectories (Third Party-Owned)

Low Cost Community Shared Solar (1 MW) (SREC-III BAU 10-Year, Third Party-Owned, Cost Basis, $/MWh)						
Installed Capital Cost Trajectory	2017	2018	2019	2020	2021	2022
Low	$150	$142	$135	$134	$131	$132
Base	$186	$178	$171	$170	$168	$172
High	$231	$224	$217	$217	$217	$224

However, it is important to note that it is very uncommon for systems that represent High Cost project types to be economical to the point of deploying in the marketplace on a competitive basis unless incentives are set at particularly lucrative levels.

4 Task 2: Comparative Evaluation of Solar Policy Alternatives

4.1 Task 2 Assumptions & Methodology

4.1.1 Deployment Goals

For purposes of this analysis, the successor solar program is assumed to commence January 1, 2017 and to have a target of an additional 1600 MW_{DC} reached by the end of 2022. Annual program targets are assumed to be spread evenly over each year, in six equal increments of 267 MW_{DC} per year, as shown in Figure 26.

In practice, the various policy alternatives (described in Section 1.4) would reach their deployment goals in different manners. The CB/SO policy alternative can most easily keep on track with the annual MW target goals just by setting the MWs sought to equal the annual target (taking into account some level of attrition). With an SREC-III structure, annual incremental MW targets can be indirectly controlled by modifying the compliance obligation levels for a carve-out program (although the SREC-I and SREC-II targets have been established in a dynamic, supply-response manner, resulting in an irregular deployment pace). When creating a DBI program, one can model and approximate program growth based on factors such as expected cost trajectory and federal incentives; but unless those actual factors matched the modeled factors, it is likely that a DBI program (in practice) would have more rapid, slower, or more volatile growth patterns than a CB/SO or SREC-III program.

In order to develop a meaningful apples-to-apples comparison of ratepayer impacts, regardless of expected volatility of deployment under two of the three policy alternatives, it was assumed for modeling purposes that the policy alternatives would deploy the same amount of MW in each year for each policy alternative in each year.

Figure 26 – Annual Incremental Program Targets

4.1.2 Approach to Deployment Modeling

For this analysis, SEA developed a deployment model to forecast installed PV capacity for the three policy alternatives. This model divides the 612 project types discussed in Section 1.3 into 15 groups, termed "Competition Groups". Competition Groups represent differentiated market sector and size categories. The Competition Groups are listed in Table 24.

Community Shared Solar, Affordable Housing, and Canopy projects greater than 1 MW were not modeled. Also not modeled were Community Shared Solar projects equal to or less than 250 kW. Instead, the analysis assumes any projects that fall into these groups will have the same required incentive and returns as similar projects between 250 kW-1 MW. For example, we explicitly estimate costs and model Community Shared Solar of 1MW, but not for a 2MW project. For simplicity a 2MW Community Shared Solar project is assumed to have the same $/kW costs as a 1MW Community Shared Solar project.

SEA assigned annual target installed capacities for each Competition Group for each year. The targets are constant across policy alternatives, so as to reflect reasonably consistent distributions of project types across policies, and to minimize masking cost differences among policies due to different risk profiles, financing and administrative costs, with differences in deployment patterns. The project types with the lowest incentive requirements within each Competition Group will be installed until the annual installed capacity target for that Competition Group is reached. Each project type is also constrained by several variables which in some cases can prevent a Competition Group from reaching its annual target, as described further below.

Table 24 – Deployment Modeling Competition Groups (kW_{DC})

Competition Group
Under 25 kW
Rooftop 25-250 kW

Affordable Housing 25-250 kW
Canopy 25 - 250 kW
Rooftop 250-1000 kW
Ground Mount 250-1000 kW
CSS 250-1000 kW
Affordable Housing 250-1000 kW
Canopy 250-1000 kW
Landfill 250-1000 kW
Brownfield 250-1000 kW
Ground Mount > 1000 kW
Landfill > 1000 kW
Brownfield > 1000 kW
Rooftop > 1000 kW

4.1.2.1 *Constraints on Technical Potential*

It is assumed that each sector's supply chain can only grow at a reasonable rate, as opposed to (for instance) quadrupling from one year over the prior year. In addition, there are aggregate technical potential constraints (e.g., there are only so many suitable landfills for solar development in the Commonwealth) that the modeling needs to take into account.

The first constraining variable is the initial 2017 installation rate of the project type. This initial installation rate is a function of historic SREC-II installations of that project type, as well as what is currently in the development pipeline.[32]

If a project type has an effective incentive low enough to be selected in the deployment model, the model assign a MWs deployed (or built) in the calendar year.

SEA assumes that for modeling increases in potential deployment of a project type increase in proportion to the decline in incentive requirements. For example, if the required incentive decreases by 25% then the base market deployment increases by 25% compared to the prior year.

In addition, the model constrains this "growth" to a minimum and maximum annual growth rate. For this modeling exercise, SEA has set the minimum growth rate at 10% for all Competition Groups, and the maximum growth rate ranges from a low of 30% to a high of 100% per year. The Competition Groups which survey respondents considered constrained were assigned a lower maximum growth rate than others. In addition, Competition Groups which exhibited ample growth throughout the historic SREC

[32] "The pipeline" is considered to be those projects qualified for SREC-II but not yet operating as of DOER's April 19, 2016 SREC-II Qualified Units List.

programs are assumed to have a lower maximum growth rate than those which were not as robust. For example there are only a few MWs of solar canopies installed or in the pipeline across the Commonwealth; thus it is much easier for solar canopies with low saturation to achieve high year-over-year percent growth rates than for a more mature / saturated market segment (e.g., Affordable Housing).

Project type installations are also constrained by the total installed capacity technical potential throughout the successor program. This potential is based on the market participant survey results, historic installations, and the pipeline.

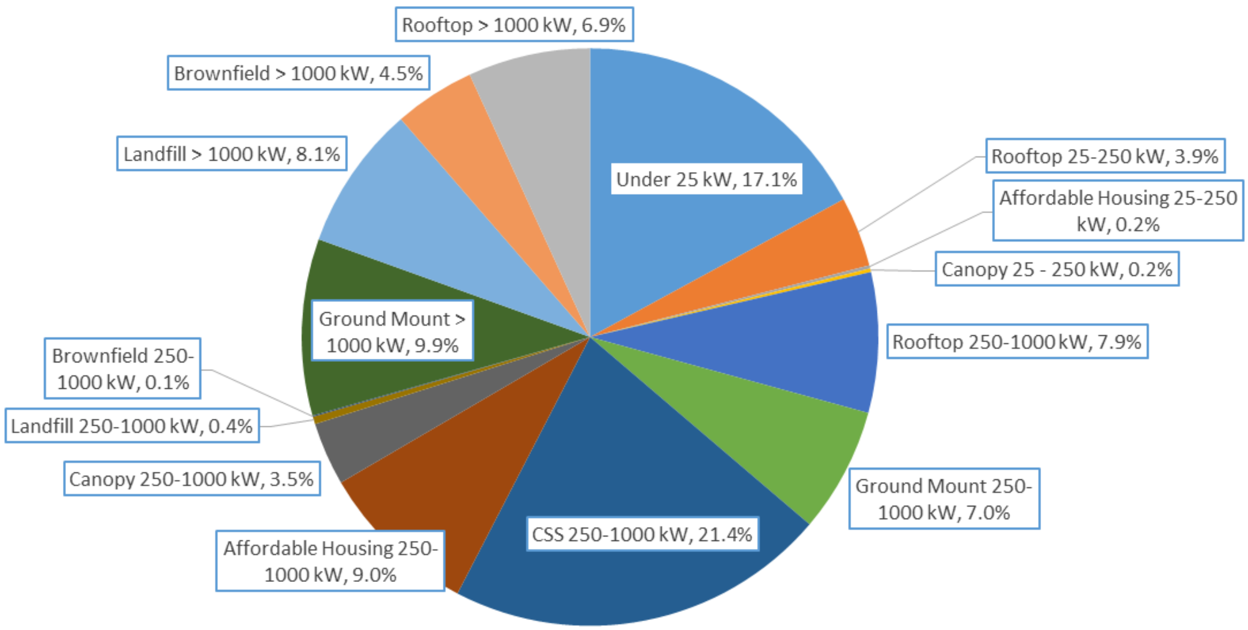
4.1.2.2 *Modeling Solar PV Deployment for Policy Alternatives Analysis*

To model the rate of deployment associated with each competition group, SEA developed two deployment cases, which are described below. Each potential deployment case assumes varying target installation rates for each Competition Group for 2017 through 2022, which are expressed as percentages of the annual total 267 MW_{DC} per year program target MWs introduced in Section 4.1**.**

4.1.2.2.1 Initial Approach: Historic SREC-II Market Share

Initially, SEA had planned to assume, at DOER's request, that the weighted average 2017-2022 deployment to different market sectors, or market share, would follow their historical SREC-II market share between Competition Groups. The targets within this initial deployment case were determined using the sum of historic SREC-II installations and qualified but not operational SREC-II capacity as of DOER's April 19, 2016 SREC-II Qualified Units List update. As previously mentioned, Affordable Housing, Canopy, and Community Shared Solar exceeding 1000 kW are not modeled explicitly as Competition Groups, but are instead included in the respective 250 -1000 kW Competition Groups in accounting for accounting for the historic SREC-II installations and pipeline. Figure 27 shows the Historic SREC-II Market Share case percentage targets by Competition Group. For this case, the targets remain constant for each Competition Group for each year of the program.

Figure 27 – Historic SREC-II Market Share Deployment Case: Annual Target Percentages by Competition Group



The specific purpose of this approach was to provide an effective "apples-to-apples" comparison between the three policy alternatives under consideration.

However, as a result of the technical potential constraints described in Section 3.1.2, some Competition Groups fail to meet the target installed capacity in the later program years. Thus, SEA believes that deployment based on historic SREC-II capacity would only produce approximately 1,500 MW by 2022 unless other market sectors (Competition Groups) are allowed to expand. Table 25 shows the modeled incremental installed capacity for the Historic SREC-II Market Share Deployment Case by Competition Group. The red shaded cells indicate the result of technical potential constraints being reached, and thus the annual target not being met for that Competition Group and the total deployment falling short of the 1600 MW aggregate target. Affordable Housing 250 – 1000 kW and Landfill > 1000 kW both fail to meet their respective targets in 2020 through 2022. Brownfield > 1000 kW cannot reach the program target in 2022. The total program shortfall is about 100 MW.

Table 25 – Historic SREC-II Market Share Deployment Case: Actual Incremental Installed Capacity by Competition Group and Program Year

Competition Block	2017	2018	2019	2020	2021	2022
Under 25 kW	45.56	45.56	45.56	45.56	45.56	45.56
Rooftop 25-250 kW	10.44	10.44	10.44	10.44	10.44	10.44
Affordable Housing 25-250 kW	0.48	0.48	0.48	0.48	0.48	0.48
Canopy 25 - 250 kW	0.54	0.54	0.54	0.54	0.54	0.54
Rooftop 250-1000 kW	20.94	20.94	20.94	20.94	20.94	20.94
Ground Mount 250-1000 kW	18.65	18.65	18.65	18.65	18.65	18.65
CSS 250-1000 kW	57.00	57.00	57.00	57.00	57.00	57.00
Affordable Housing 250-1000 kW	23.99	23.99	23.99	11.12	12.23	4.24
Canopy 250-1000 kW	9.42	9.42	9.42	9.42	9.42	9.42
Landfill 250-1000 kW	1.12	1.12	1.12	1.12	1.12	1.12
Brownfield 250-1000 kW	0.18	0.18	0.18	0.18	0.18	0.18
Ground Mount > 1000 kW	26.36	26.36	26.36	26.36	26.36	26.36
Landfill > 1000 kW	21.64	21.64	20.20	12.33	4.16	4.61
Brownfield > 1000 kW	12.09	12.09	12.09	12.09	12.09	6.76
Rooftop > 1000 kW	18.27	18.27	18.27	18.27	18.27	18.27

4.1.2.2.2 The "Modified Market Share" Scenario

As an alternative to the initial deployment scenario, a "Modified Market Share" deployment case was developed that would ensure that the market would reach 1,600 MW_{DC}. The Modified Market Share case accounts for technical potential constraints by reducing the annual targets for constrained Competition Groups later in the program. In this deployment case, the Under 25 kW target is fixed at 30% of the total annual program target for 2017 through 2022, while other sectors (such as Community Shared Solar 250 – 1000 kW) also have a smaller modeled market shared than in the Historic SREC-II Market Share case.[33] In this case, the unconstrained Competition Groups' market share increases as the constrained groups' market share decreases. Table 26 shows the market share of each Competition Group in 2017 through 2022. Landfill, Brownfield, and Affordable Housing market shares decrease from 2017 to 2022. Unconstrained or less constrained groups such as Rooftop and Canopy market shares increase from 2017 to 2022 to make up for lost market share in other groups.

[33] SEA notes that under real-life market conditions, other sectors may command a larger or smaller market share than the "Modified Market Share" approach suggests. However, these market shares are used as a simplifying assumption for estimating the relative cost to ratepayers of each policy alternative, and are not the product of larger-scale market modeling.

Table 26 – Modified Market Share Deployment Case: Annual Target Percentages by Competition Group and Program Year

Competition Block	2017	2018	2019	2020	2021	2022
Under 25 kW	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%
Rooftop 25-250 kW	6.0%	6.0%	6.0%	6.0%	6.0%	7.5%
Affordable Housing 25-250 kW	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%
Canopy 25 - 250 kW	0.8%	0.8%	0.8%	0.8%	0.8%	0.8%
Rooftop 250-1000 kW	8.5%	8.5%	8.5%	8.5%	10.0%	10.0%
Ground Mount 250-1000 kW	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%
CSS 250-1000 kW	15.0%	15.0%	16.5%	16.5%	17.5%	17.5%
Affordable Housing 250-1000 kW	5.0%	5.0%	5.0%	5.0%	4.5%	4.5%
Canopy 250-1000 kW	3.5%	3.5%	3.5%	5.5%	5.5%	5.5%
Landfill 250-1000 kW	1.0%	1.0%	1.0%	1.0%	0.5%	0.5%
Brownfield 250-1000 kW	1.0%	1.0%	0.5%	0.5%	0.5%	0.5%
Ground Mount > 1000 kW	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%
Landfill > 1000 kW	6.0%	6.0%	5.0%	4.0%	2.5%	2.5%
Brownfield > 1000 kW	5.0%	5.0%	5.0%	4.0%	4.0%	2.5%
Rooftop > 1000 kW	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%

For the Task 2 analysis, the deployment applies the Modified Market Share approach to estimate the cost to ratepayers under each alternative policy.

4.1.2.3 *Specific SREC-III Market Condition Assumptions*

In order to simulate different conditions in the SREC market without undertaking extensive market modeling falling outside of the scope of this analysis, SEA took the incentive requirement over the project's lifetime (as determined in Task 1), and calculated the minimum annual SREC revenue ($/MWh) over time, as a function of the Alternative Compliance Payment (ACP) and Clearinghouse Auction floor price trajectories. The year-over-year rate of decline of the ACP and auction floor price match the expected cost reductions associated with a large, greenfield, ground-mounted system, so as to ensure that clearing SREC prices match the decline rate of the most cost-effective PV systems.

SEA's approach and assumptions related to establishing the level and trajectory of the SREC-III cap (ACP) and floor prices are summarized below:

- SEA assumes from an investor's perspective SREC transactions would clear at 5% below either the ACP rate (in times of shortage) or the auction price (in times of surplus). Thus, in effect, no one can actually realize a price as high as the actual ACP rate due to transaction costs, but when supply is short prices clear 5% below this rate.
- SEA further assumed for the purpose of establishing estimated ratepayer costs that the market would clear 50% of the time near the ACP and 50% of the time near the soft floor. Thus for simplicity SEA assumes this expected value of SREC costs that load serving entities will pass on to their customers who are the ratepayers.
- Two different cases for assumed **investor expectations** were utilized.

   - Required SREC III ACP and auction floors were established based on an assumption that, for the purposes of financing, a lender or investor would assume that SREC prices would be at the auction floor price <u>all ten years</u>, representing a very conservative (and higher cost) assumption.
   - Alternatively, investors assume 3 years at the ACP rate and 7 years at the auction price.

  Thus, a world in which financiers assume 10 years of SREC revenue at the auction floor price, the system in question would need a higher auction price to get the project to meet its financing revenue requirements, than a world where it was assumed that 7 years the SREC price was at the auction price and 3 years at the ACP rate.

- Broker fees were assumed to be 7% of SREC prices for projects up to 25 kW DC, and 3% of SREC prices for all other projects.
- That an auction floor price was set as a fixed 30% discount to the ACP rate; and
- That ACP rates decline 7% year-to-year (rather than 5% under SREC-II).

4.1.3 Determining Net Ratepayer Costs by Future Policy Alternative

To calculate the net ratepayer cost of each policy alternative associated with all systems deployed under the “Modified Market Share” case discussed above, SEA calculated both 1) direct ratepayer costs and 2) sources of offsetting value impacting cost to ratepayers. These cost categories are detailed in the following sections.

4.1.3.1 *Scope of Net Ratepayer Cost Analysis*

4.1.3.1.1 Direct Costs to Ratepayers

The direct ratepayer costs include:

- The total revenue required by an investor over a 25 year system life from all available revenue streams (including both commodity and incentive revenue) to meet investor’s risk-appropriate return requirements; and
- The total value of administrative costs to EDCs, program administrators and developers ultimately borne by ratepayers.

4.1.3.1.2 Sources of Offsetting Value

The sources of offsetting ratepayer value, which are netted from the direct costs to ratepayers, include:

- The total wholesale energy market value of incentivized solar PV production, whether realized through directs sales by the generator, net metering credits, avoided purchases, or by resales to the market by EDCs purchasing bundled supply from generators;
- The total value of capacity (as it affects Forward Capacity Market costs to load) realized or avoided by solar PV incentivized by the program; and,
- The total value of market-priced Massachusetts Class I RECs whose purchase is avoided due to procurement of RECs from incentivized solar PV projects.

In addition, SEA includes a qualitative discussion of “policy transition costs”, which are costs that may exceed the quantified program administrative costs.

4.1.3.1.3 Discount Rate

SEA distilled these net cash flows impacting ratepayers into a single comparative metric - net present value (NPV) in 2016 dollars - utilizing the same 5% nominal discount rate used in the 2015 Net Metering and Solar Task Force Final Report (Grace, et al., 2015).

4.1.3.2 ***Revenue Requirements of Solar PV Systems Deployed***

From the perspective of Massachusetts' ratepayers, the costs directly incurred by ratepayers (prior to any directly-avoided costs) as a result of any given solar PV incentive program include:

1) the value of net metering credits (paid to solar PV project owners and non-owner solar net metering off-takers)[34];
2) lost distribution revenue as a result of self-supply; and,
3) the value of SRECs or RECs purchased by EDCs and other load-serving entities (LSEs).

Under the SREC-based programs modeled in this analysis, the cost to ratepayers is, as described above, the expected value of SRECs based on varying potential SREC price outcomes. However, for the "bundled" policy alternatives (the hybrid competitive bid/standard offer and declining-block incentive programs), the total cost of incentives to ratepayers is merely the total volumetric bundled payment (in $/MWh) needed to deploy projects to desired levels. The accounting of these costs does not differ by policy alternative, but is directly related to the total amount of solar PV incentivized by the program.

Under the Solar Carve-Out and Solar Carve-Out II programs, most generators were able to take advantage of net metering, which allows participants to receive compensation exceeding wholesale rates. However, for the purposes of this ratepayer cost analysis (as discussed in Section 4.2), it is assumed that the market value of production under the proposed program will be the wholesale rate, whether generation is sold directly to the grid, or value is derived through net metering credits. Given that behind-the-meter energy usage allows customers to avoid paying the full retail rate (which include several embedded utility costs) that must be recovered from ratepayers through the Net Metering Recovery Surcharge (NMRS) or an EDC's revenue decoupling mechanism (RDM), the "effective" incentive payment for each type of system deployed includes both the solar incentive and the shifted T&D revenue, and mathematically, represents the difference between the system's revenue requirement and the wholesale rate for all of the energy generated. This can be stated as:

$$\begin{aligned}&Levelized\ Effective\ Incentive\ (for\ Each\ Deployed\ System)\\&\qquad = Revenue\ Requirement - Monetized\ FCM\ Revenue - Wholesale\ Energy\ Value\end{aligned}$$

Thus, the total cost to ratepayers of solar PV revenue requirements represents the discounted value of the sum of all "effective incentive" payments and ISO-NE wholesale energy value over the life of all projects deployed under the program.

[34] This differs from the NM&STF approach of 3rd-party ownership deals where net metering credit agreements or onsite electricity sales are monetized by the 3rd –party at a discount in order to entice the offtaker into an agreement. For modeling simplicity, no discount was applied for this modeling exercise.

4.1.3.3 *Program Administration Costs*

Another direct and quantifiable cost to ratepayers considered is the incremental program administration costs passed on to ratepayers. These costs fall into two categories:

- the costs to EDCs and/or program administrators associated with administering an incentive program; and,
- the overhead costs to project developers that exceed what such entities would have spent in the absence of the program, and which would be expected to be passed along in cost in a sustainable business model.[35]

A continuation of SREC-II into a SREC-III BAU program would not cause EDCs to incur any material additional program administrative burden beyond the quarterly bulk procurement costs currently incurred to satisfy the Solar Carve-Out and Solar Carve-Out II requirements (which would be similar to their procurement for RPS Class I RECs). Assuming that the EDC would run the procurements under the Hybrid CB/SO and the DBI policy futures, an EDC's costs to administer either solar program are assumed to include primarily the cost of personnel needed run the program. Each of these programs as defined for this analysis would comprise "bundled" purchases from many individual solar PV installations, and thus require EDCs to spend time and personnel resources on:

- Managing competitive solicitations for systems (in the competitive bid policy future);
- Administering the purchases under contract or tariff (under both Hybrid CB/SO and DBI); and
- Monetizing the energy, RECs and (potentially) capacity into various markets.

These activities include a mix of fixed startup and ongoing costs, as well as variable costs per Class I REC sold into Massachusetts and regional compliance markets.

This analysis updated the estimates developed in the Net Metering and Solar Task Force Final Report to account for a program beginning in early 2017 (Grace, et al., 2015).

Under a competitive bid program, project developers would incur added overhead costs exceeding basic administrative costs, given that they must sell, develop and submit multiple bids for each system ultimately chosen. Based on research conducted for the NM&STF, SEA estimated that developers must submit, in total, 2.5 bids per single bid ultimately selected. In other words, the population of developers bidding into the market must incur in aggregate 1.5 "dry holes" for every successful project, and 'dry hole' cost represents additional overhead compared to an open incentive program in which developers must make one sale per development / PPA contract.

The NM&STF analysis estimated a fleet-wide average incremental Commercial PV customer acquisition cost, based on National Renewable Energy Laboratory data, as has estimated approximately $0.05/W. These costs – consisting of system design, marketing and sales, and other related costs, must be recovered in the revenue from PV system bid prices. An extra 1.5 sales per winning bid would therefore

[35] Under the current SREC construct, the cost of running the auction is funded within the spread between what buyers pay and sellers receive. However, these values are already contained in our analysis and thus do not have to be accounted for additionally.

yield an expected $0.075/W higher cost of competitive bid programs to ratepayers. For the purposes of this analysis, SEA has assumed that:

- This added "dry hole" premium would only apply to systems larger than 250 kW DC, which would be subject to competitive procurement under the case in question; and,
- As a modeling simplification because the dry hole premium was estimated as one-time $/Watt cost, the added cost of doing business is added to administrative costs in a one-time lump sum associated with the deployment year rather than spread-out over the program life by a commensurately higher bid to cover the dry hole costs.

Overall, the cost to ratepayers of program administration (both to developer and EDCs) can be described as the sum of all incremental EDC overhead costs in the DBI and Hybrid CB/SO policy alternatives and the total developer overhead incurred in the Hybrid CB/SO alternative only.

4.1.3.4 *Wholesale Energy Value*

While under the long-term contracts within the DBI and Competitive Bid policy futures ratepayers must effectively pay for the total revenue requirement and incremental program administrative costs, the incremental cost to ratepayers of solar incentives explored in this study are net of value of the commodities created by the PV system. Of these directly avoided costs, the largest such avoided costs are the market value of energy produced by the PV systems, whether that value is derived from avoided energy purchases or from offsetting cash flows associated with EDC resale of energy procured into the ISO New England wholesale market. The value of wholesale energy prices used to determine avoided wholesale energy values is described in Section 3.1.4.4 (Hornby, et al., 2015).

For the cost of the solar incentives to be compared across the different policy futures on an apples-to-apples basis, SREC-III incentives (which only pay for the SRECs) must be compared against the bundled total contract payments under DBI and Competitive Bid policies, net of these offsetting revenues.

4.1.3.5 *Generation Capacity and Capacity Reserve Value*

Another key component of an analysis of directly-avoided ratepayer costs is avoided generation capacity costs. Distributed generation resource participation in the forward capacity market (FCM) is a complex and evolving landscape. To date, only a very small minority of solar PV has historically participated in FCM, while the vast majority has not (ISO New England, 2016). Under some circumstances per net metering tariffs, EDCs can assert rights to FCM, but historically the EDC has not done so. These practices may well change over time. As a result, accounting for the amount of FCM being monetized is not straightforward.

However, when the generator does directly monetize FCM to which it is entitled under ISO-NE rules (related to production during reliability hours), the solar PV incentive required would be reduced by this supplemental revenue stream. For instance, FCM revenue would offset the SREC incentive requirement under the SREC-III BAU policy. If the bundled procurement in the CB/SO or DBI policy alternatives conveyed FCM rights to the purchasing EDC, then the EDC would sell off (or otherwise value) this value to similar effect, reducing the calculated estimate of the incentive. Even if capacity is not purchased as part of the bundled purchases under the Hybrid CB/SO or DBI policy alternatives, if the EDC asserts it rights under net metering tariffs, the EDC can offset the net ratepayer cost of incentives by monetizing this value.

Even if FCM is not monetized, the existence of distributed PV creates value to ratepayers by reducing peak load as measured at wholesale metering points of the Massachusetts EDCs (this requirement is allocated to all entities serving load in the EDC territories). Reduction in this manner reduces the installed capacity requirement by the actual peak reduction in addition to the associated reserve percentage. Consistent with this discussion, the ISO's distributed generation working group recently incorporated the solar PV forecast net of the quantity of capacity expected to be monetized in the FCM market to the load forecasts used to set the ICR for FCM purposes (ISO New England, 2016). Since ratepayers directly benefit from all distributed PV in this manner from a reduced ICR, this value has been used to adjust the net ratepayer incentive cost calculation. When FCM is not monetized, the whole value of peak reduction applies; when monetized, the same whole value applies, although in practice composed of (i) direct monetization of the FCM value as discussed above, plus (ii) the total value less the monetized FCM value. As can be seen, the sum of (i) and (ii) equals the FCM's ELCC value.

These avoided values include the total value of avoided purchases from the ISO-NE Forward Capacity Market associated with solar PV, as adjusted by solar PV's contribution to meeting system peak demand. To accomplish this task, SEA multiplied the total forecasted FCM value contained in AESC 2015 by an expected effective load carrying capability (ELCC) value, and adjusted upward to account for avoided generation reserve margin.

ELCC can be measured largely as a function of the change in peak load associated with a certain penetration of solar PV. According to the North American Electric Reliability Corporation (NERC), any generator's ELCC can be understood as a function of its ability to materially reduce the probability of shedding load at a moment of high demand on a given bulk power system, also known as "loss of load probability" (LOLP). In other words, if PV is unable to reduce LOLP at any given moment, it cannot be considered as having capacity value (North American Electric Reliability Corporation Integration of Variable Generation Task Force, 2011). Thus, the degree to which distributed solar PV resulting from the examined policy reduces the ISO-NE installed capacity requirement (ICR) is assessed.[36]

As discussed in great depth in the NM&STF Final Report, solar PV production is highly coincident with summer peak hours (but not perfectly so) and its output differs at different hours of the day. Once a sufficiently large quantity of PV is deployed, the timing of peak demands shift to later hours in the day, until (theoretically) an additional unit of solar PV would have "no incremental impact on peak reduction" (Grace, et al., 2015). While project developers bidding projects into the FCM are unable to count anything beyond a system's weighted average annual ISO-NE claimed capacity (the maximum

[36] For the Net Metering and Solar Task Force Task 3 Analysis & Report, SEA developed an Excel-based solar production model, which uses PV Watts-derived production shapes for a variety of PV system types located in Worcester, MA, including residential, commercial rooftop, utility scale fixed-tilt and solar canopy systems, multiplies those production shapes against the total expected capacity by typical system type, and compares that production against an implied ISO-NE load shape for a peak day in 2014 in Massachusetts. SEA adapted that model to this analysis to determine an ELCC percentage associated with solar PV penetrations assumed, and applied those values to the forecast of future FCM prices described in this section.

monetizable value in the FCM, which does not change with overall penetration levels), the distribution-level ELCC of a state's "fleet" of solar PV systems represents the total reduced cost of generation component of the retail rate enjoyed by ratepayers (Grace, et al., 2015). For the purposes of this analysis, SEA assumes that the incremental capacity added through the new solar incentive program would follow the "Modified Market Share" deployment case discussed in Section 4.1.2.2.2, which results in ratepayers receiving the same capacity value across policy alternatives.

Typically, when calculating the net ratepayer costs of a given program, it is important to maintain a narrow focus on the impacts associated only with that program. However, applying this approach too strictly in the case of capacity value likely would overstate the capacity value of solar PV systems, given that such value is the direct result of the total solar PV capacity in Massachusetts - not merely what is installed under the program. Thus, in order to better simulate the declining marginal capacity value of solar PV, it is important to account for solar PV generation capacity that may be installed after the end of the program. To simplify this portion of the analysis, SEA assumed that the annual deployment rate of solar PV systems under the new solar program (267 MW_{DC} per year) would hold constant through 2050, which results in the total deployment of 6,826 MW_{DC} through 2050. SEA further assumed that sufficient generation capacity would be deployed in later years such that production would remain constant from systems that had reached the end of their economic lives.

Figure 28 shows SEA's forecast of the relationship of ISO-level (and Massachusetts-specific) distribution-level ELCCs to both total penetration of solar PV, as well as the penetration-insensitive annualized ISO-NE claimed capacity value. As discussed in the NM&STF report, the gap between these figures represents the total "externality" value ratepayers ultimately enjoy through a reduced Basic Service or competitive supply charge.

Figure 28 – Illustration of Gap between Solar PV's Maximum Monetizable Forward Capacity Market Value and Actual Capacity Value Accruing to Ratepayers

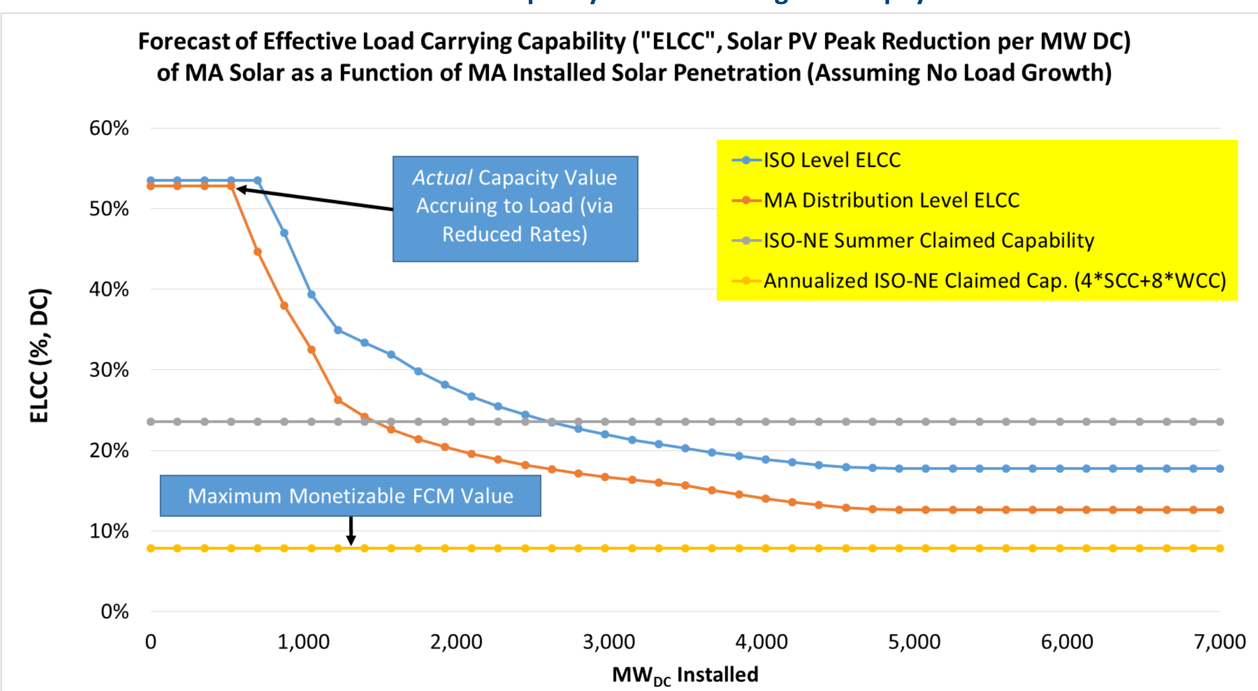


Figure 29 shows the same distribution-level ELCC trend as a function of time. As noted above, the graph demonstrates that even though a new solar program is intended to hit its target capacity of 1,600 MW_{DC}[37] as of December 31, 2022, the effective capacity value of PV continues to drop as systems deploy after 2022. Ratepayers will continue to enjoy capacity value from these systems through 2046, the final year of the economic lives of the systems deployed under the program.

Figure 29 – Illustration of ELCC/Annualized SCC Gap for 25-Year System Lives of 2017-2022 Systems

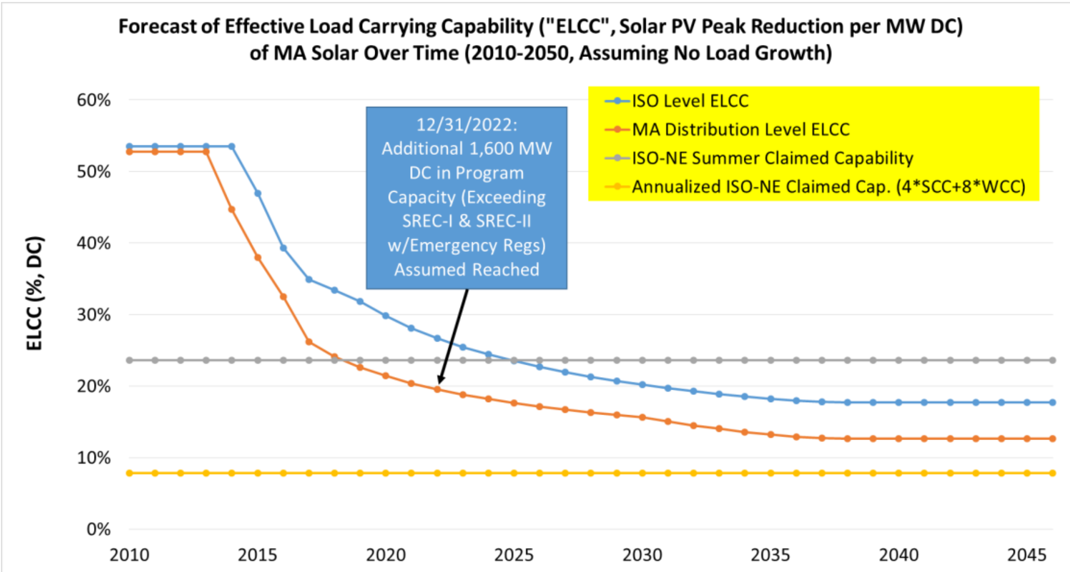
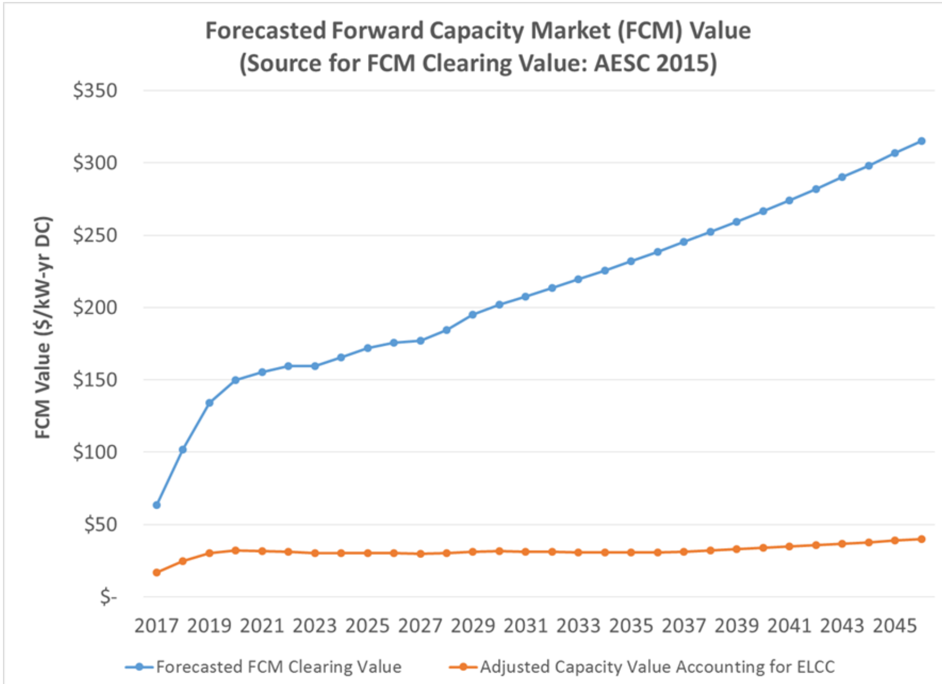


Figure 30 displays the final forecasted FCM values (in \$/kW-year) from AESC 2015 used in this analysis, as well as the effective capacity value of solar PV to ratepayers. Overall, these values are similar between the deployment cases used in this analysis.

[37]The 1,600 MW_{DC} figure is in excess of total SREC-I and SREC-II capacity (inclusive of capacity enabled by emergency regulation), which SEA forecasts will be 1,810 MW_{DC}.

Figure 30: Comparison of FCM Clearing Value and ELCC-Adjusted PV Capacity Value ($/kW-yr DC)



In addition, by reducing overall peak demand, distributed solar PV, like energy efficiency measures, also directly reduces the need for marginal reserve capacity in proportion to its ELCC. Thus, the total avoided reserve margin can be determined by multiplying the total avoided capacity cost by the value for expected reserve margin (Norris, et al., 2015). For this analysis, SEA used a 17% reserve margin and a forecast of Forward Capacity Auction (FCA) clearing prices, both of which were sourced from AESC 2015 (Hornby, et al., 2015).

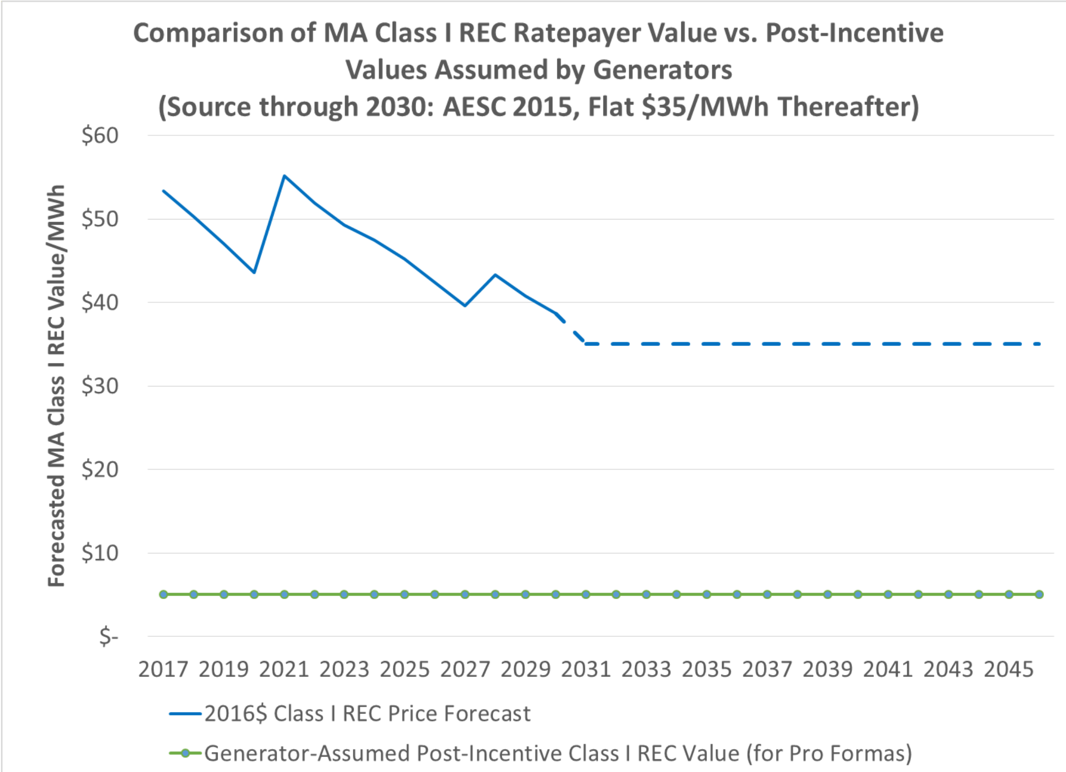
Thus, the total value to ratepayers of solar PV capacity can be stated as the NPV of the total value of ICR reduction provided by PV systems deployed under the program, plus the total reduction in required reserve capacity.

4.1.3.6 *Avoided Massachusetts Class I REC Payments*

In addition to avoided ratepayer energy and capacity costs, solar PV generation under the new program is, at a minimum, either 1) eligible to be retired to meet EDC or other LSE Class I RPS requirement (under a non-SREC policy alternative) or 2) reduces the need to purchase additional Class I RECs (under an SREC-III carve-out from the Class I RPS). Thus, the incremental solar policy cost accounts for avoiding a Class I REC purchase from other sources in all policy futures. To estimate the avoided ratepayer cost associated with foregoing Class I REC purchases, SEA utilized the forecasted Class I REC values from the publicly-available AESC 2015 through 2030 (adjusted to nominal dollars), with a flat $35/REC nominal value applied in all years thereafter (Hornby, et al., 2015).

Figure 31 below shows this hybrid Class I REC price forecast, which SEA applies across all policy alternatives.

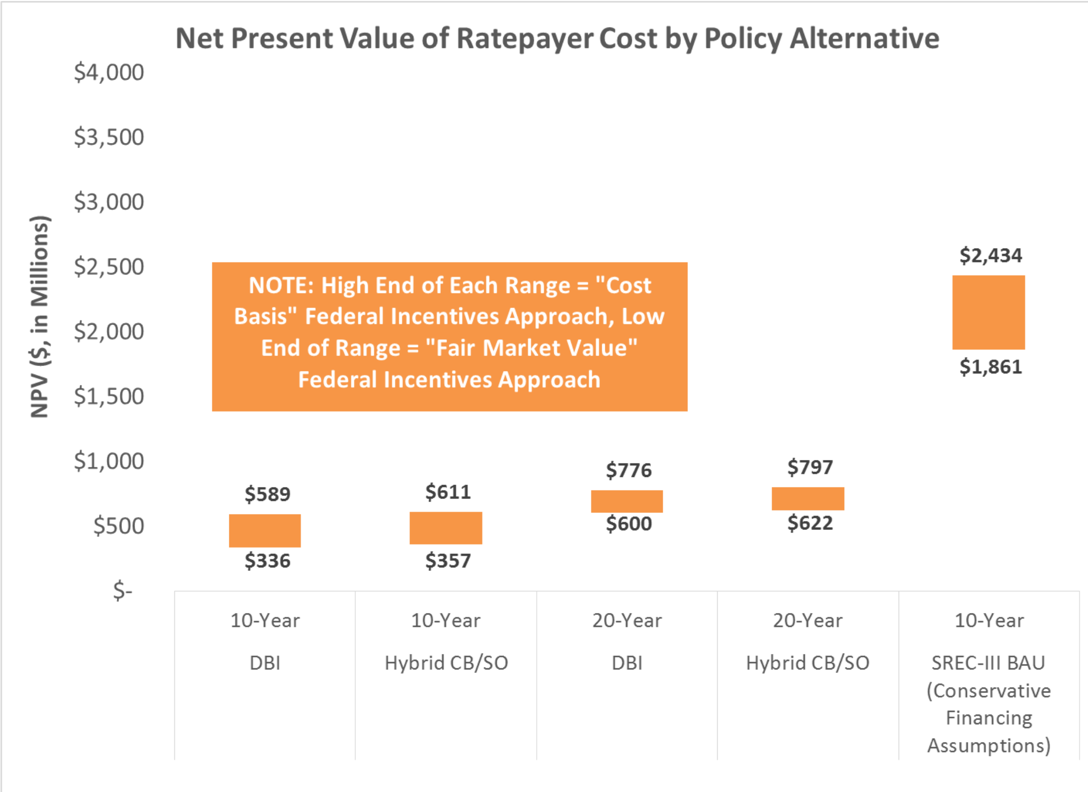
Figure 31 - Forecasted MA Class I REC Values for Determining Avoided Ratepayer Class I REC Costs



4.2 Task 2 Results: Net Ratepayer Cost of Policy Alternatives

As in the revenue requirement results described in Section 4.1.3.2, SEA finds that the cost to ratepayers of each of the three policy types considered in this analysis, as measured by net present value (NPV) of cost to ratepayers, varies significantly depending on whether project developers take depreciation and the ITC on the basis of the system's cost, or its "fair market value". The results are presented assuming that the market uniformly elects one approach or the other, so as to provide an effective sensitivity analysis (shown in Figure 32).

Figure 32: Range of NPVs by Policy Alternative and Treatment of Federal Incentives



4.2.1 Federal Tax Benefit Monetization Scenarios

Assuming developers of all third party owned systems elect to use the cost basis for calculating depreciation, our analysis suggests that the Hybrid Competitive Bid / Standard Offer (Hybrid CB/SO) and DBI program types represent a significant ratepayer cost savings relative to a business-as-usual extension of SREC-II. Among these cases, the least expensive policy alternative for ratepayers is the DBI approach, given that ratepayers would not be required to effectively cover developer "dry hole" costs associated with unsuccessful bidding. On the other hand, the SREC-III policy alternative represents the highest cost set of cases of all. Figure 33 compares the net direct ratepayer costs across all policy alternatives and incentive durations on a "cost basis" to monetizing federal incentives. The same relative results are found in which all third-party developers are assumed to use the "fair market value" approach to taking depreciation and the ITC. However, the overall cost to ratepayers of such a scenario is significantly lower in the "fair market value" scenario, given that a significant degree of "effective incentive" passed on to ratepayers is absorbed by federal taxpayers. Figure 34 below illustrates the relative net costs to ratepayers between policy, deployment and incentive duration cases when assuming the "fair market value" approach.

Figure 33 - NPV of Net Direct Ratepayer Costs under "Cost Basis" Approach to Federal Incentives

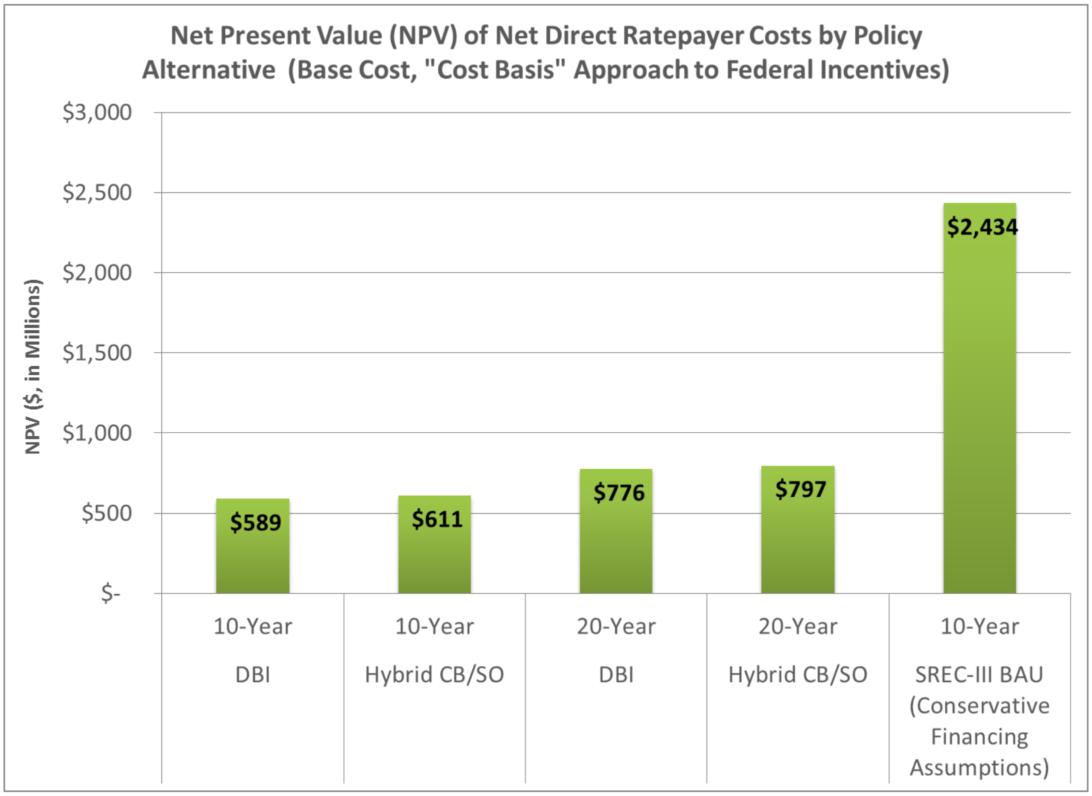
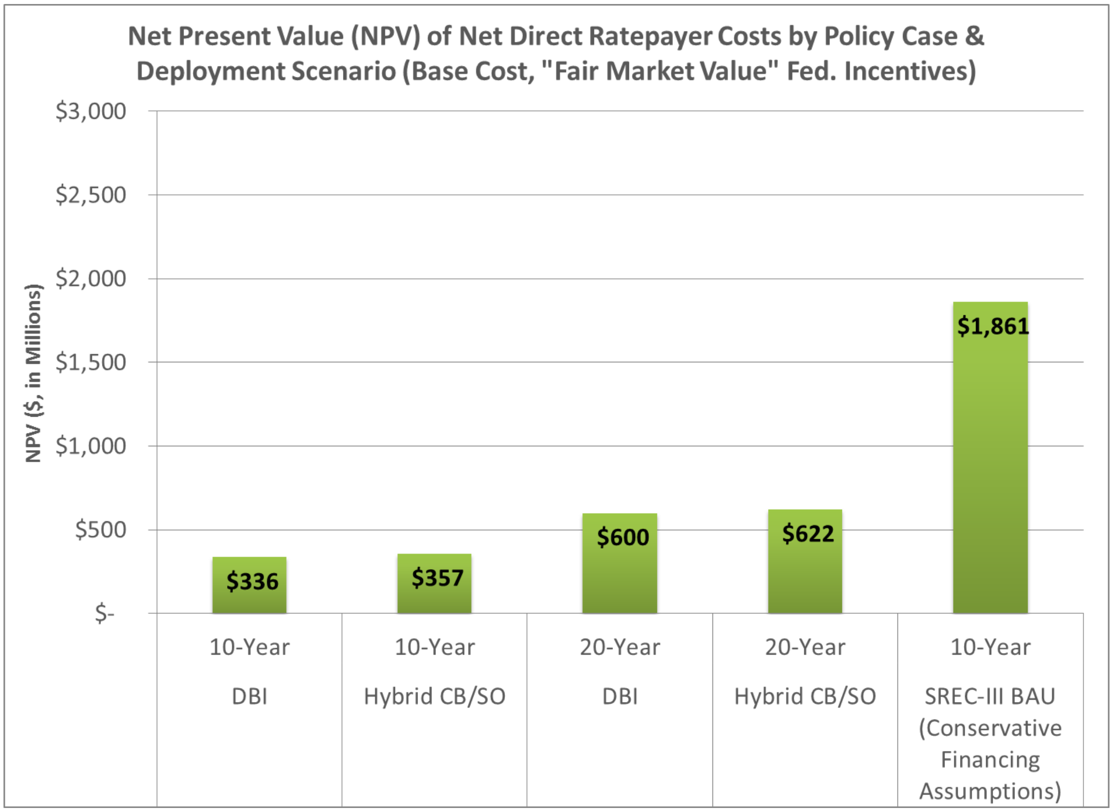


Figure 34 - NPV of Net Direct Ratepayer Costs under "Fair Market Value" Approach to Federal Incentives



4.2.2 Base Cost Case Results by Net Ratepayer Cost Component

Overall, the SREC-III BAU cases represent a higher cost to ratepayers largely due to the fact that developers seeking financing under SREC-III cases are expected to need a higher cost of capital to meet debt and equity investor expectations than the bundled Hybrid CB/SO and DBI policy alternatives. Thus, under the SREC-III cases, the cost of revenue requirements to ratepayers is elevated relative to the non-SREC cases. Table 27 and Table 28 below illustrate each component of the net direct cost to ratepayers for each policy alternative, deployment scenario and SREC-III BAU 10-year market expectation case.[38]

[38] Some totals in both tables may not be exactly equal, given that within each scenario, the composition of the Project Types deployed are slightly different for each Policy Alternative.

Table 27 - NPV of Net Direct Ratepayer Costs by Component under "Cost Basis" Approach (NPV in 2016$, Millions)

Policy Alternative	DBI (10-Yr)	Hybrid CB/SO (10-Yr)	DBI (20-Yr)	Hybrid CB/SO (20-Yr)	SREC-III BAU (Conservative Financing Assumptions) (10-Yr)
Cost Case	Base	Base	Base	Base	Base
Revenue Requirements	$4,633	$4,633	$4,820	$4,820	$6,567
Administrative Costs	$91	$113	$91	$113	$0
Direct Ratepayer Costs	**$4,724**	**$4,746**	**$4,911**	**$4,932**	**$6,567**
Generation Capacity & Capacity Reserve Value	$738	$738	$738	$738	$738
Wholesale Energy Value	$2,423	$2,423	$2,423	$2,423	$2,422
Avoided Class I REC Costs	$974	$974	$974	$974	$974
Offsetting Ratepayer Value	**$4,135**	**$4,135**	**$4,135**	**$4,135**	**$4,133**
Net Direct Ratepayer Costs	***$589***	***$611***	***$776***	***$797***	***$2,434***

Table 28 - NPV of Net Direct Ratepayer Costs by Component under "Fair Market Value" Approach (NPV in 2016$, Millions)

Policy Alternative	DBI (10-Yr)	Hybrid CB/SO (10-Yr)	DBI (20-Yr)	Hybrid CB/SO (20-Yr)	SREC-III BAU (Conservative Financing Assumptions) (10-Yr)
Cost Case	Base	Base	Base	Base	Base
Revenue Requirements	$4,379	$4,379	$4,642	$4,642	$5,995
Administrative Costs	$91	$113	$91	$113	$0
Direct Ratepayer Costs	**$4,470**	**$4,491**	**$4,734**	**$4,755**	**$5,995**
Wholesale Energy Value	$738	$738	$738	$738	$738
Generation Capacity & Capacity Reserve Value	$2,422	$2,422	$2,422	$2,422	$2,422
Avoided Class I REC Costs	$974	$974	$974	$974	$974
Offsetting Ratepayer Value	**$4,134**	**$4,134**	**$4,133**	**$4,133**	**$4,133**
Net Direct Ratepayer Costs	**$336**	**$357**	**$600**	**$622**	**$1,861**

4.2.3 Explaining Ratepayer Cost Differences between 10-Year and 20-Year Incentives

Superficially, it might appear, given that 10-year incentives require higher costs per megawatt-hour of solar production than a 20-year program, that the latter type of program would be less expensive for ratepayers. However, this is not the case. Even though the unit cost of "effective incentives" under a 20-year program is much lower than under a 10-year program, the cost to ratepayers of 10-year programs is significantly lower than under a 20-year program for two reasons:

- The total incentive needed beyond ISO-NE wholesale rates does not drop by half after incentive durations are doubled, and
- While the required return to finance a project varies by policy alternative, an investor's required return is always significantly higher than the 5% discount rate assumed for ratepayers. Thus, a longer incentive duration will result in the financing costs compounding, and exceeding the assumed ratepayer discount rate, over 20 rather than 10 years.

As an example, Figure 35 shows the annual undiscounted values for each component of net direct ratepayer cost associated with a 10-year DBI policy alternative, assuming the "fair market value" approach and a market share distribution that allows the market to produce 1,600 MW by 2022. As the graph shows, the payout of 10-year incentives reaches its maximum in 2026, increases the total cost to ratepayers in the early years of the program, but is outweighed on a net basis by avoided wholesale energy, capacity and Class I REC costs beginning in 2029. Given a 5% discount rate for ratepayers, a higher degree of net avoided ratepayer costs closer to 2017 results in a proportionately lower overall program cost to ratepayers.

On the other hand, as Figure 36 shows, the fact that the overall required incentive is not halved when conveyed on a 20-year basis leads to ratepayers realizing a net undiscounted benefit for the first time in 2038, a full ten years later than in an identical 10-year case. Thus, the net savings to ratepayers beginning in 2038 has less value from the perspective of ratepayers in 2016.

Figure 35: Shape of Undiscounted Net Ratepayer Costs & Value Given a 10-Year Incentive Stream

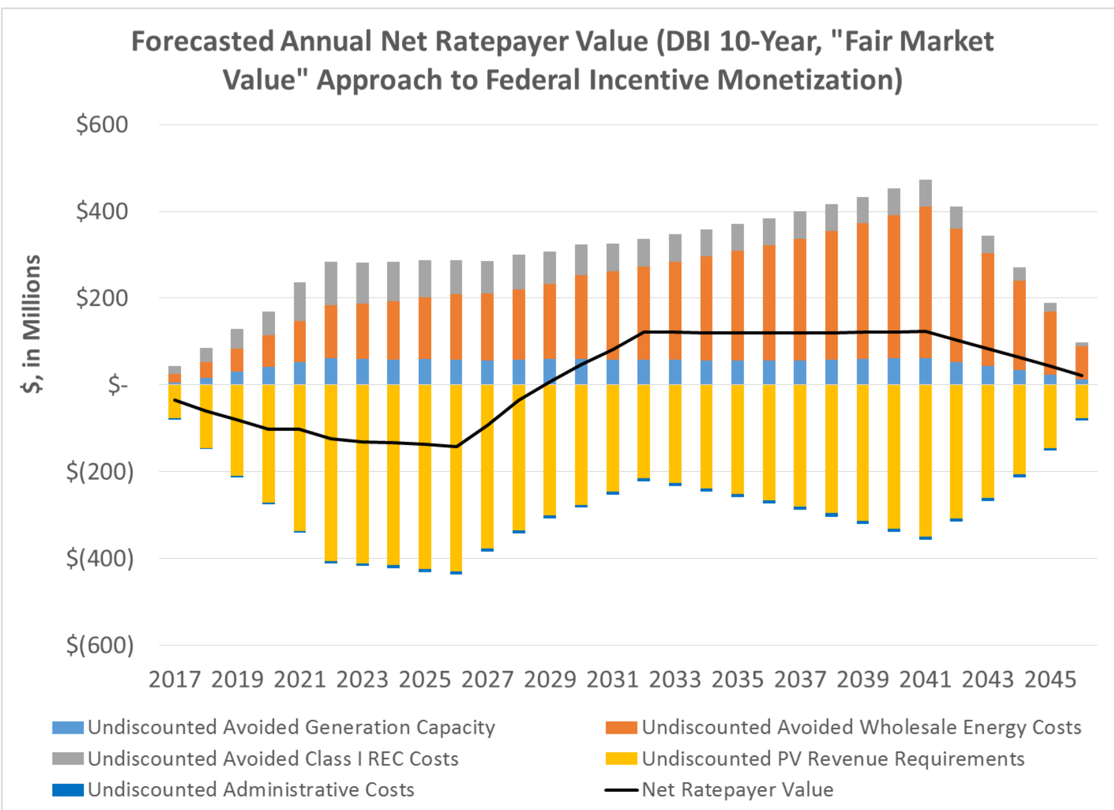
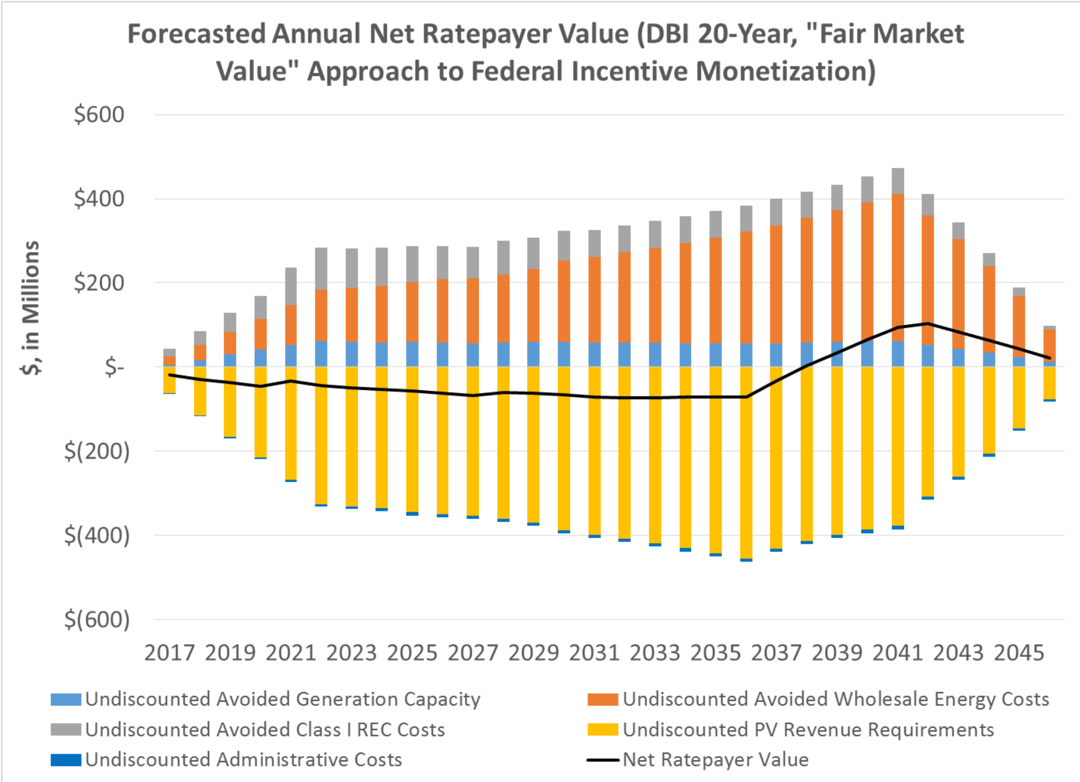


Figure 36: Shape of Undiscounted Net Ratepayer Costs & Value Given a 20-Year Incentive Stream



4.2.4 SREC-III BAU (10-Year) Financing Sensitivity

Under an SREC-III future, assumptions on future SREC prices have to be made for financing. SREC prices (by design, and based on past experience with the model) tend to be binary, either near the ACP (price cap) in times of shortage or near the auction floor in times of surplus. A debt financier (such as a bank or other lender) is likely to assume cash flow to a project associated with a future that might be characterized as a number of years near either the cap or near the floor. Overall, SEA assumed that these financers tend to be conservative. Thus, the SREC-III "Conservative" case corresponds to a case in which financiers assume for their pro-forma purposes an SREC cash flow equivalent to SREC prices being near the floor for 7 years and near the ACP for 3 years, while the "Very Conservative" case assumes cash flow likely be exceeded with 90% probability (often referred to as a "P90" case, with prices at the soft price floor for all 10 years.[39] SEA assumes that higher levels of financier conservatism translate to less

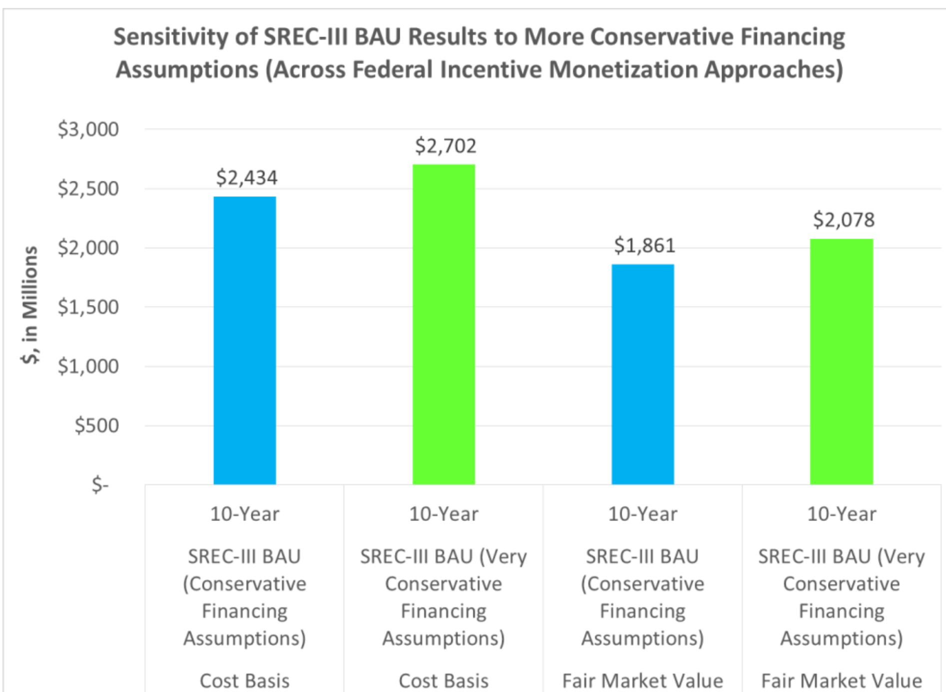
[39] Based on SEA's analysis of the SREC markets (Grace, et al., 2015), over-the-counter market SREC hedges (i.e. long-term rather than spot SREC sales) have tended to trade at a discount to expected long-term cash flows, which would produce revenues to project owners which might have a similar ultimate impact on required incentive. In other words, generators sell their SRECs to risk-taking market participants at a discount and those risk-taking market participants seek to take advantage of a significant arbitrage opportunity by selling the SRECs to compliance buyers at a profit. Ultimately, ratepayers paying for compliance absorb costs at the higher rate at which compliance entities purchase the SRECs. See Figure 41 of Task 3 Report of Net Metering and Solar Task Force for an illustration (Grace, et al., 2015).

debt leverage (resulting in a higher overall cost of capital), and thus direct costs to ratepayers. Thus, there is an inverse relationship between the amount of debt used to finance the project and the number of years prices are assumed to be at the floor. However, SEA believes it is possible that as lenders become more comfortable with the policy, they would be more likely to lend against the SREC revenue stream, and thus assume more years at the ACP.

In order to better understand how investors might react to a perceived SREC-III market (as an extension of SREC-II), SEA undertook a sensitivity in which an investor assumes that a project will not receive any revenue beyond the auction floor for all 10 years the project is eligible for SREC-based incentives. In such a scenario, the investor would effectively finance less of the project at normal rates, or would increase their required return, thus increasing the need for incentives for the system to deploy.

Figure 37 below illustrates the results of this sensitivity analysis as compared with a scenario in which a financier assumes a minimum of 3 years of SREC revenue at the ACP, under both the “cost basis” and “fair market value” approaches to monetizing federal tax incentives. While the change results in a $200-$300 million net increase in ratepayer cost, these findings suggest that the investor’s risk perception does not significantly alter the basic relationship of the SREC-III BAU policy alternative to the other bundled-purchase alternatives (Hybrid CB/SO and DBI) in terms of its net ratepayer cost. Indeed, SEA believes it would be unreasonable for an investor to assume a market sufficiently in shortage that market prices would be at the ACP for more than 5 years of the ten-year incentive duration for any given project built between 2017 and 2022.

Figure 37 – Comparison of SREC-III BAU Results (Assuming More Conservative Financing Assumptions)



5 Qualitative Risks and Uncertainties

5.1 Policy Transition Costs

5.1.1 Moving Away from SREC Structure

”Policy transition costs” can be thought of as those costs above and beyond administrative costs as discussed above in Section 4.1.3.3 (Program Administrative Costs). The Net Metering and Solar Task Force report[40] addressed this issue qualitatively, while identifying the magnitude of such costs exceedingly difficult to quantify.

> *“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… 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… 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… . 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.”” (Grace, et al., 2015)*

Gleaning from the above, the potential transitional costs imposed on ratepayers from increased cost of financing when transitioning away from a SREC structure are primarily related to financing. If current financiers leave the market permanently and are not replaced, this leaves less capital to invest in projects; lower supply could lead to higher financing costs. If financiers depart and are replaced, financing costs could be higher during a transition period, while investors perceive more risk and until they get educated and comfortable with the new market structure. More generally, a transition could mean less over development, which could make the Massachusetts market unappealing to investors.

[40] See Section D.9.6 on Policy Transition Frictional Costs. (Grace, et al., 2015). Also note that the Net Metering and Solar Task Force report approach took into account multiple perspectives (non-participating ratepayers, customer generator, non-owner participant, and the societal perspective of citizens of Massachusetts at large), while this analysis is focused solely on the ratepayer impacts.

It is clear from the survey comments that many, if not most, respondents have become familiar with the SREC structure and either prefer it or have learned to work within the construct. Thus, it is also clear that if the successor program is effectively an "SREC-III", most survey respondents will have minimal trouble adapting to the new regime.

Conversely, in the commentary, there are many cogent arguments made that fixed price contracts via a DBI or competitive bid structure with long-term contracts with the utility will bring down financing costs. Indeed, this is what the analysis assumes for the cost of capital inputs for modeling both system and ratepayer costs.

5.1.2 Transitioning to a Competitive Bid-Based Structure

Beyond the potential policy transition costs of moving away from a SREC structure, transitioning to a competitive bid-based structure could trigger additional specific transition costs. Overall, moving to a competitive bid structure would likely provide the most significant "shock to the system" for the broader market. Certainly, it is very likely that some market participants that have ignored Massachusetts because of its complex SREC structure would now find the market more appealing. Nevertheless, many survey respondents made clear their dislike of the Connecticut ZREC and the RI Renewable Energy Growth programs – particularly for larger projects. Critiques included complaints of these programs' artificial nature, including:

- having to recruit customers without knowing if they will win the bid and ultimately get to enter into a long-term contract;
- the detrimental market impact of speculative bidding (as a result of projects awarded contracts based on prices that are not financeable), and
- the general desire not to waste the time and resources of either the developer or the would-be project host or off-taker.

Additional critiques include that only large national developers can afford to play in such a market, and that local and regional developers would get squeezed out. Further, given respondent inputs, one could argue that a RI REG or Connecticut ZREC structure may not be able to attain the aggressive development goals set forth in this analysis (adding another 1600 MW_{DC} of installations by the end of 2022). Naturally, falling short of policy goals also means falling short of achieving the associated ancillary (societal / non-ratepayer) benefits. While these all may be worthy critiques of a competitive bid structure which should be taken into consideration when choosing a successor program to SREC-II, these critiques do not appear to accrue any readily quantifiable direct ratepayer impacts beyond those this study has aimed to quantify under the administrative costs category or described above in Section 5.1.1 when transitioning away from a SREC structure.

5.1.3 Transitioning to a Declining-Block Program

The dislike of the competitive bid program expressed by some respondents was not similarly directed at a DBI program. The survey responses suggest that a DBI program would be less of a shock to survey respondents. Aside from the manner in which incentive rates are established, one of the significant differences between a DBI and a competitive bid structure is the schedule and process through which incentives are accessed. Competitively bid incentives are awarded through periodic solicitations whereas DBIs are provided on a rolling or open-ended basis (assuming all eligibility and other selection criteria are met, of course). As a result of its more fluid nature, a DBI market allows project development activities to move forward without the administrative starts and stops of periodic competitive bidding and associated evaluation, or the host frustrations associated with developers closing sales for projects that don't ultimately get selected. Of course, the transition between incentive blocks in a DBI markets will cause some degree of disruption. In all, survey responses suggest that the evolution to a DBI structure would be less of a shock to market participants (and the project development process) than a transition to a competitive bidding structure – although either change would provide for more market disruption than a SREC-III alternative. Again, as with a competitive bid structure, regardless of potential transition costs, these critiques do not appear to accrue any readily quantifiable direct ratepayer impacts beyond those this study has aimed to quantify under the administrative costs category or described above in Section 5.1.1 when transitioning away from a SREC structure.

5.2 Underlying Market Structure Risks

To simplify the comparison of policy alternatives, SEA has assumed a simplified market in which the Effective Incentives are the Required Incentives less wholesale revenue. However, these assumptions do not describe the market within which PV is currently developed or may be developed in the future. For example:

- For SREC-II, many projects will be evaluated assuming avoided retail rates or net metering credits under current market conditions. If a SREC-III model is pursued as the successor program, then these higher energy revenues and perhaps capacity revenue will provide some of the cash flows to finance the project development. Under the DBI or CB/SO approaches, the availability of these revenue options could result in lower solar incentive requirements.
- Rate design changes - in which more utility revenue is garnered from demand or monthly customer charges than the current rate structure – and/or "Access Fees" - that could apply to both new and existing generators- could potentially alter the cash flows seen by project investors. Both approaches have been proposed by National Grid's Massachusetts Electric unit in its rate case (DPU Docket 15-155).

All policy approaches examined could be impacted by any of these factors; depending on how they were implemented this could increase project costs or could decrease project revenue (or have no impact on costs or revenue).. Putting aside for a moment how this might affect projects that were already developed, prospective projects could be affected as follows if such changes to the underlying market structure occurred while the incentive program was ongoing (and incurred increase costs or decreased revenue):

- A competitive bid program could adjust in its next bid cycle with participants bidding at commensurately higher levels to meet revenue requirements impacted by the aforementioned rate changes;
- If costs fall less steeply than DBI (or less revenue is accrued), a DBI program can grind to a halt (though if some sort of adjustment mechanism were incorporated into program as in CA

REMAT's Renewable Energy Market Adjusting Tariff, the issue could be addressed over time); and,

- As costs increase or revenue declines, in the short-term some projects would not meet their revenue requirements and SREC-III development would decline. If the development decline were precipitous, SREC Factors could be adjusted over time or (in the longer term) low SREC supply could cause SREC prices to approach the Solar Alternative Compliance Payment level, and spur development.

Perceived market risk will have an overall impact on required rates of return. Financiers will take into account the potential lost revenue, and thus higher incentives required by any policy alternative (though an SREC-III program would probably be most vulnerable to such market risks because of its reliance on the energy revenue separate from SREC revenue).

Another market risk was brought up by one survey respondent for bundled programs. If in the bundled program the counter party of the long term contract is the utility, then the revenue would be dependent upon utility solvency. On a less dire scale, cash flow would be reliant on the utility's prompt processing of payments. As such, late payments by (or disputes with) the utility could put the project's entire revenue stream at risk. Downgrades on utility credit ratings also could affect the project financing and liquidity (specifically, the ability to sell a project to another market participant). Of course, this survey respondent's observations hold true for any counter party of any bundled long-term contract – especially where all of the project's revenue is derived from a single source.

6 Limitations of Analysis and Potential Areas for Further Analysis

As SEA's quantitative analysis of the three policy options suggests, the net cost to ratepayers of a third solar incentive program has a wide potential range, regardless of which approach DOER may choose. In this section, SEA describes the limits of this analysis, as well as ways in which the analysis could be enhanced.

6.1 Modeling the Impact of Market Forces

An overarching objective of this analysis is to make as close to an "apples-to-apples" comparison on a net ratepayer cost basis between the three policy alternatives under consideration. After considering various ways to do so, SEA and DOER jointly determined that the simplest approach to do so was to develop a uniform PV deployment scenario across all policy alternatives (as detailed in Section 4.1.2.2.2). SEA took this approach in order to continue to ensure that the market will produce a diverse array of system types (subject to technical limits, also as discussed in Section 4.1.2.2.2).

However, this means that SEA did not ultimately apply the type of dynamic supply/demand models it typically uses for forecasting deployment and incentive levels. For example, in the context of the SREC-II market, SEA typically employs such market models to forecast SREC forward prices and deployment by market sector in REC-based markets, as such modeling was outside of the scope. Instead, for the purposes of this analysis (and regardless of the policy alternative under consideration) SEA assumed that incentives should be set to induce a sufficient volume of deployment from each Competition Group given the “Modified Market Share” deployment case. Thus, SEA was unable to determine exactly what systems would economically “clear” (and be built) if the SREC-II ACP and auction floor values were extended into the future under an SREC-III BAU program at the same rates of decline currently expected for the SREC-II program. Furthermore, this approach limited SEA’s ability to differentiate these projects by their SREC factors (which allow somewhat less economic projects to clear in a dynamic SREC framework).[41] Similarly, in the context of the bundled programs, using a set deployment case and 15 separate competition groups does not allow for examining the potential for lower-cost systems to “clear” if fewer Competition Groups were modeled.

Thus, the question of which policy would produce a lower total cost to ratepayers can only be fully investigated with full-fledged modeling of the competitive economic dynamics of the Massachusetts solar market, thus relaxing the modeling constraints of uniform deployment across policy alternatives and of using 15 separate competition groups necessary to preserve market diversity. While outside of this report’s scope, employing more robust market models allows for a more robust forecast of the cost impact for all three policy scenarios that reflects conditions and constraints present in a more realistically dynamic market - in which a wider array of market forces better determine deployment and relative market share among installation types.

6.2 Firming an SREC-III Auction Floor

By manipulating various design details, the differences between policy futures can be reduced. One key limitation of this analysis is the absence of considerations which could be employed to maintain an SREC market structure while lowering its cost to ratepayers. A prime example is firming the SREC-III BAU’s price floor.

However, as currently constructed, a key limitation of this analysis is the lack of an SREC-III sensitivity with a firm floor. While the current SREC-II structure utilizes a “soft” auction floor, it is possible to design a program with a guaranteed minimum price (similar in design to the firm price cap created by an ACP). This approach could be further engineered by adding SREC factors to account for cost and site suitability, as utilized in SREC-II.

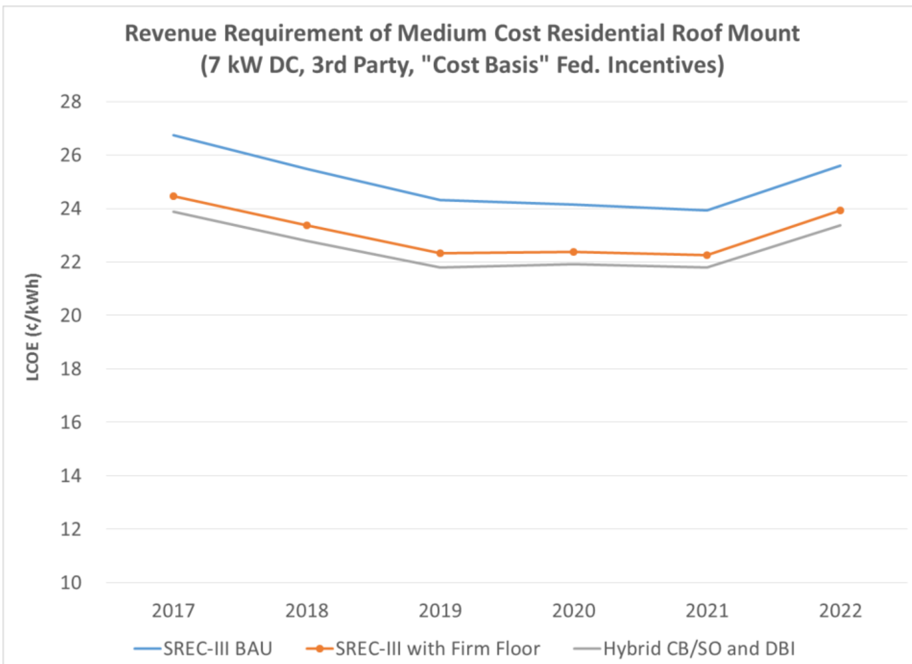
Generally, designing a program with a firm floor could minimize the overall degree of investor risk associated with an SREC-based program, and thus reduce the overall cost of PV revenue requirements passed on to the Commonwealth’s ratepayers. Furthermore, setting a declining firm price floor at a lower level than the current auction floor could induce developers to focus on ways to trim costs in a manner that follows both price signals, thus reducing net ratepayer cost even further. However, this approach could result in reduced overall diversity in the market, given that a poorly-designed market-

[41] SEA observes that, in effect, SREC-II itself only has two “Competition Groups” – systems equal to or less than 25 kW DC, and all other systems not subject to a set-aside.

wide firm floor could conceivably price entire Competition Groups out of the market. Thus, the level at which a firm floor might be set (or the SREC factors used) would have to be approached with care and consideration.

To illustrate the potential impact of firming the price floor (for example, by creating a buyer of last resort at the floor price). Figure 38 shows the relative revenue requirement in an SREC-III case with a firmed auction floor at current levels (as discussed in the SREC-III assumptions section above). As can be seen in Figure 38, a firm price floor can be accompanied by a lower ACP in a manner that brings the SREC revenue requirement very close to the Hybrid CB/SO and DBI revenue requirements.

Figure 38 – Potential Revenue Requirement Comparison of SREC-III Firm Floor with Other Policy Alternatives (Using Medium Cost Residential Roof Mount)



DOER has a wide variety of potential levers it can call upon when designing and/or implementing a firm floor. For example:

- If the floor price were set at the auction price, the perceived SREC revenue risk would decrease, thus decreasing expected value of revenue needed to satisfy financing requirements. The firming of the floor would then mean to meet the new revenue requirements compared to the status quo of a soft floor, the following could occur;
    - The ACP could be lowered (the closer the ACP gets to the floor price, the closer the policy resembles a fixed production incentive policy);
    - The floor price could be lowered; or,
    - Both the ACP and floor price could be lowered (albeit not as much).

If the firm floor were set far below the auction floor (e.g., $100/SREC), then it would have little or no impact as the financeable revenue from the less certain ACP and soft floor would still be higher than the more certain financeable revenue from a firm floor. As the firm floor price increases and approaches the soft floor auction price, more market participants would view the firm floor as a substitute with higher financeable revenue then the expected value of the ACP and soft floor. Thus it might be possible to lower the expected value of the combination of the ACP and the soft floor, and thus decrease ratepayer impacts.

While outside the scope of this report, full analysis of a modified SREC design with a firm price floor may reveal additional insight as to whether such an SREC approach could yield sufficiently similar ratepayer cost results as the other models, while avoiding both the increases in administrative costs quantified herein, and the unquantified policy transition costs that would be borne by market participants (developers, financiers, brokers/market makers, etc.) in moving away from an SREC approach.

6.3 Developing a 20-Year SREC-III Case

While it is likely that doing so would represent an added cost to ratepayers (for reasons detailed in Section 4.2.3), it is possible (as discussed in Section 3.2.1.2) for a third SREC program to allow participants to receive a 20-year revenue stream, which would result in incentives with a lower unitized ($/MWh) cost.

However, SEA has not modeled the net ratepayer cost of such a case. As a result, it is not possible to make a full comparison between the Hybrid CB/SO and DBI 20-year cases with similar results for an SREC-III BAU program.

To remedy this, SEA could potentially develop a 20-year SREC case, perhaps also in the context of developing a more robust SREC-III case with a firmed auction floor. However, it is likely that such a policy alternative would cost ratepayers more (again, for reasons as discussed in Section 4.2.3), which may require additional adjustments (modeled or otherwise) to reduce its overall cost.

6.4 Alternative Deployment Cases (e.g., Front-Loading or Back-Loading of Program Targets)

Unlike the SREC-III BAU scenario, the two key non-SREC bundled purchase options ultimately have a lower net cost to ratepayers across a variety of different scenarios, due in significant part to the ability to access less expensive capital. In addition, as described above, SEA models the Hybrid Competitive Bid / Standard Offer policy alternative as being significantly lower in cost than a SREC-III policy, but only slightly more costly to ratepayers than the DBI approach due to the “dry hole” risk premium (as discussed in Section4.1.3) ultimately passed on through higher total system costs. However, each of these approaches can be made more economically efficient and less costly to ratepayers than in the initial modeling cases undertaken here.

As SEA and its fellow analytical team members described in the *New York Solar Study*, program cost control can be accomplished with both volume- and price-based limitations (New York State Research and Development Administration, 2012). As discussed in Section 4.1.1, the Hybrid CB/SO and DBI policy alternatives modeled in this analysis assume equal deployment levels in each year.

However, it is possible to enhance the level of ratepayer cost control built into each policy design (for example) by back-loading the total capacity procured or contained within the defined capacity blocks of the DBI policy alternative. The potential ratepayer benefit of such an approach may derive from the strong probability of total PV system cost reductions under both base and low installed capital cost trajectories (discussed in greater depth in Section 3.2). However, such an approach may carry risk, especially if system costs follow a higher installed capital cost trajectory, given that back-loading would be of less significant benefit for ratepayers, and would slow down market development in prior years relative to a uniform deployment trend. Analysis of alternative deployment trajectories could yield additional insight into policy design approaches that balance industry development with ratepayer cost.

6.5 Influence of Potential Utility-Scale Construction Lag on Federal Investment Tax Credit (ITC) Utilization

A key change to the ITC included in the legislation extending and stepping down the credit (Consolidated Appropriations Act, 2016 (H.R.2029), 2015) alters the basis for claiming the applicable credit from being "placed in service" to "property (under) construction", so long as the property under construction reaches commercial operation before January 1, 2024. While the IRS (Internal Revenue Service, 2016) allowed for as long as 4 years to pass between qualifying for under construction or equivalent safe harbor, and commercial operation, we assume that solar projects are more likely to take up to 2 or 3 years if availing themselves of the safe harbor provisions. Even so, determining appropriate incentives in 2020, 2021 and 2022 resulting from this change could be rather complex, given that larger-scale solar projects commencing construction in those years (or earlier) could claim an ITC value that is significantly higher than the value associated with that year. However, the impact on total cost to ratepayers could be material.

6.5.1 Limitations of Current Analysis

As noted in Section 3.1.4.5, SEA assumed (for simplification purposes) that all projects qualifying in any given year will begin construction and reach commercial operation in that year. Furthermore, SEA assumes that project tax equity investors will claim the credit on systems reaching commercial operation on the same schedule shown in Table 29 corresponding with the date of commercial operation. Thus, the analysis, as currently structured, does not account for tax equity investors claiming credit amounts that exceed the ITC's apparent value in the years in which the systems reach commercial operation. In practice, for example, a project reaching commercial operation on December 31, 2022 could claim the incentive level applicable in 2019 (at the extreme), 2020 or 2021. As such, setting incentives based on these apparent annual values may significantly overstate the required incentive needed to ensure that these systems are properly financed and deployed. As Table 29 shows, the total reduction in revenue requirement for projects 1 MW_{DC} or larger taking between 2 and 3 years could reach nearly 12%. While the year in which the tax credit is taken likely will not be known to DOER in the process of setting incentives for 2022 (or any other year affected by these provisions of the tax law), the totals shown in this report for total ratepayer incentive are likely overstated.

Table 29 - Effect of Construction Lag on ITC Usage for Systems Larger than 1 MW (1000 kW) Deployed in 2022 (3rd Party, "Fair Market Value")

Project Type and Modeled Size (kW DC)	LCOE (Systems w/2022 COD, ¢/kWh)			LCOE Range (2020 & 2021 Const. Start, ¢/kWh)	% Difference Range (2020 & 2021 Const. Start)
	10% ITC (2022 Const. Start	22% ITC (2021 Const. Start)	26% ITC (2020 Const. Start)		
Campus Lot Canopy (1000)	16.75	15.27	14.82	1.48-1.93	8.8%-11.5%
Medium Cost Community Shared Solar (1000)	17.62	16.39	16.03	1.22-1.59	6.9%-9.0%
Medium Cost VNM LIH (1000)	15.58	14.37	14.01	1.21-1.58	7.8%-10.1%
Large Building Mounted (1000)	13.66	12.65	12.34	1.01-1.32	7.4%-9.7%
Medium Landfill (1000)	15.96	14.72	14.34	1.24-1.62	7.8%-10.2%
Large Landfill (4000)	13.98	12.76	12.39	1.22-1.59	8.7%-11.4%
Medium Brownfield (1000)	15.39	14.16	13.79	1.23-1.60	8.0%-10.4%
Large Brownfield (4000)	13.19	12.04	11.68	1.16-1.51	8.8%-11.5%
Medium Cost Ground Mount (1000)	13.59	12.55	12.24	1.04-1.36	7.7%-10.0%
Large Ground Mount BTM (2000)	12.73	11.69	11.38	1.03-1.34	8.1%-10.6%
Medium Cost Ground Mount (4000)	12.93	11.87	11.56	1.06-1.37	8.2%-10.6%

As a relatively simple example, Table 29 shows the potential LCOE of systems reaching COD in 2022 under various ITC levels from the two prior calendar years (22% if construction began in 2021, and 26% if construction began in 2020). Overall, the total reduction in revenue requirement could reach nearly 12% for certain systems exceeding 1 MW_{DC} - however, the year in which the tax credit is taken likely will not be known to DOER in the process of setting incentives for 2022 (or any other year affected by these provisions of the tax law).

While outside the scope of this report, DOER may find added value in analyzing the impact of these new provisions in the tax law via sensitivity analysis of system and ratepayer cost surrounding assumptions of construction lag for utility-scale projects, and how that construction lag could manifest itself in later years of the program, especially once the IRS issues further guidance on "commenced construction" provisions surrounding the ITC (Internal Revenue Service, 2016). With this information, it is possible for DOER to assess ways in which to set incentives that reflect realistic assumptions regarding the level of ITC being claimed by developers receiving a state incentive. DOER may wish to consider whether incentive levels might be set accounting for projects maximizing their tax benefits as well as potentially less than full monetization of incentives.[42]

[42] SEA notes that tax equity may become increasingly scarce over time, and that therefore assuming full monetization of these tax benefits may potentially not be appropriate.

6.6 Incorporating Forward Capacity Market (FCM) Participation into System and Ratepayer Cost Analysis

As discussed in detail in Section 4.1.3.5, only a very small minority of solar PV has historically participated in FCM (ISO New England, 2016). However, it is likely that as time progresses, more PV generators will opt to bid their capacity into the FCM.

Given the very low level of participation amongst existing PV generators in the FCM, SEA has chosen to make a conservative assumption not to model systems deploying between 2017 and 2022 as having any monetized FCM revenue. As a result, if FCM participation increases during that period, it is likely that SEA has overstated the likely incentive needed for such generators, which would reduce the overall ratepayer cost across all policy scenarios.

Thus, SEA believes there would be benefit in undertaking a cost analysis that accounts for potential generator revenues from FCM participation. In such an analysis (or analysis sensitivity), SEA could forecast participation rates amongst various project types likely to bid into the FCM if they possess such rights, the degree to which potential participants may continue to retain title to their capacity rights, and the degree of revenue such generators could expect. With this information, it is possible to determine the degree to which the levelized incentive needed to ensure such systems reach investor returns might be reduced.

Terms Used in This Analysis

Alternating Current (AC)	A flow of electric charge that can change direction. The electric system in New England uses AC, and thus requires solar PV systems to be equipped with an inverter that converts DC (defined below) to AC power.
Behind the Meter (BTM)	A project which is interconnected behind a utility meter, and thus offsets physical load onsite before transmitting excess kWh to the distribution system
Bundled Purchase	A combined purchase of the energy, capacity attributes and environmental attributes (i.e., Class I RECs for this analysis). For the purposes of this analysis, both the DBI and Hybrid Competitive Bid/Standard Offer cases are bundled purchases.
Competition Group	The fifteen (15) groups of projects created by SEA (defined below) that can be considered in "competition" with one another based on similar market sector and size category (as both terms are defined below)
Competitive Bid	An approach by which developers would be paid on an "as-bid" basis by the electric distribution companies (EDCs, also defined below) and conveyed by either tariff or contract for a given set of solar PV systems. The term also refers to a policy alternative for this analysis in which systems larger than 250 kW DC are subject to such procurement, whereas projects at or below 250 kW DC would be paid an administratively-determined rate. Thus, this policy alternative is sometimes referred to herein as a "Hybrid Competitive Bid/Administratively Determined" case.
Cost of Renewable Energy Spreadsheet Tool (CREST)	A renewable energy cost model created by Sustainable Energy Advantage, LLC for the National Renewable Energy Laboratory that is used to determine levelized cost of energy. The tool and accompanying user guide is hosted for public use by NREL at https://financere.nrel.gov/finance/content/crest-cost-energy-models.
Declining Block Incentive (DBI)	An incentive type characterized by a pre-determined "standard offer" incentive level that declines as increasing levels of nameplate capacity are reached in various competition groups. See below for a description of the "Standard Offer" policy alternative used in this analysis. It is also the policy alternative in this analysis in which a defined level of incentive is available for all systems within eligible Competition Group up through a given level of nameplate capacity (defined above), at which point the level of incentive offered to all eligible systems would decline.
"Effective" Incentive	The total unitized ($/MWh) cost borne by ratepayers for the program. This effective incentive is equal to the total revenue requirement less the wholesale energy, any monetized capacity value and a pro forma residual value for MA Class I RECs post-program incentive term.
ELCC	Effective Load Carrying Capability (as described in Section 4.1.3.5)
FCM	ISO-NE Forward Capacity Market
Direct Current (DC)/ "Nameplate"	The DC capacity of solar PV (defined below) represent the gross power from the system prior to losses due to conversion of the energy from DC to AC (defined above). DC power itself is defined as the single-direction flow of electric charge

Capacity	from a generator.
Electric Distribution Company (EDC)	The companies that deliver electric energy to the citizens and businesses of the Commonwealth (both investor-owned and municipally-owned).
Hybrid Competitive Bid / Standard Offer	Long-Term, bundled fixed-price contract or tariff, with pay-as-bid price Competitive Bidding (i.e., Competitive Solicitation) for large projects (defined as 250 kW or larger) & administratively-determined Standard Offer for smaller projects.
ICR	ISO-NE Installed Capacity Requirement
Independent Power Producers (IPPs)	Owners of generation assets selling into the ISO-NE (defined below) wholesale energy and capacity markets.
ISO New England (ISO-NE)	The independent system operator that manages the bulk power system in New England and independently administers markets for electric energy and capacity on behalf of IPPs and electric distribution companies (defined above)
London Inter-Bank Offered Rate (LIBOR)	LIBOR is used as a global baseline for calculating the value of a wide variety of inter-bank financial transactions, and thus represents, in effect, a financial institution's own cost of capital.
Market Sector	Broad types of projects as laid out in DOER RFQ and includes Rooftop, Canopy, Community Shared Solar, Landfill, Brownfield, Affordable Housing, < 25 kW, and Ground Mount projects.
MA Class I Pro Forma Residual Value	The residual value for MA Class I RECs post-program incentive term that developers and financiers will put into a financial pro forma. That is if a policy alternative is a 10 year program, then the MA Class I Pro Forma Residual Value will be garnered for years 11 through 25 (the end of the project's assumed life). The value is always assumed to be a nominal $5/Class I REC to account for the discount given to this asset given market and regulatory uncertainty.
Off-Taker	The counterparty to a power purchase agreement from a solar PV system.
Project Class	The 34 kinds of solar projects (e.g., small residential roof mount, medium landfill, onsite affordable housing) which span the range of costs, size, mounting surface, and off-taker (described above) in order to facilitate modeling a diverse solar market. These 34 kinds of solar projects fit within the Market Sectors (defined above) requested by DOER.
Project Type	The 612 CREST project "blocks" (representing 34 different Project Classes, multiplied by 6 EDCs, and by 3 ownership types (third party, host, and public-owned)
Size Category	The project size groups requested by DOER (including <=25 kW, 25-250 kW, 250-1000 kW and >1 MW direct current (DC).
Solar Photovoltaic (PV)	A technology that converts the light of the sun to useful electric energy.
Solar Renewable Energy Certificate	A financial instrument used to account for one megawatt-hour of energy created by the generation of energy by solar energy. For the purposes of this analysis, all SRECs

(SREC)	are assumed to be created by solar PV (defined above).

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