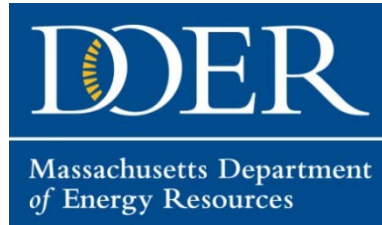# Task 2 Report: Comparative Evaluation of Current Carve-out Policy to Other Policy Alternatives

Prepared for the
Massachusetts Department of Energy Resources

By
Sustainable Energy Advantage, LLC and Meister Consultants Group, Inc.
In association with
La Capra Associates, and **The Cadmus Group, Inc.**

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About the Massachusetts Department of Energy Resources (DOER)

DOER's Mission is to create a cleaner energy future for the Commonwealth, economically and environmentally, including:

- Achieving all cost-effective energy efficiencies;
- Maximizing development of cleaner energy resources;
- Creating and leading implementation of energy strategies to ensure reliable supplies and improve relative costs; and
- Support clean tech companies and spurring clean energy employment.

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

About this Report

The Comparative Evaluation of Current Carve-out Policy to Other Policy Alternatives (Task 2 Report) was completed in support of the Massachusetts Department of Energy Resources' Solar Policy program and post 400-MW policy analysis under a competitive contract awarded to The Cadmus Group, Inc.

As part of the effort, The Cadmus Group, La Capra Associates, Meister Consultants Group, and Sustainable Energy Advantage developed five companion reports:

Task 1: Evaluation of Current Solar Costs and Needed Incentive Levels across Sectors
Task 2: Comparative Evaluation of Carve-out Policy with Other Policy Alternatives,
Task 3a: Evaluation of the 400 MW Solar Carve-out Program's Success in Meeting Objectives
Task 3b: Analysis of Economic Costs and Benefits of Solar Program, and
Task 4: Comparative Regional Economic Impacts of Solar Ownership/ Financing Alternatives.

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1 Introduction

Solar policy design can affect PV system development costs and the cost of investment capital in ways that may impact required incentive levels.[1,2,3] For example, incentive programs that successfully attract lower-cost debt financing result in a lower overall cost to ratepayers than incentive programs which do not provide sufficient stability for lenders and can only attract higher-cost equity investments. All else equal, higher return targets require higher incentive payments. In addition, some incentive designs may introduce complexities into the development process that increase transaction costs for prospective system hosts and increase risk for system developers. Higher transaction costs and development risks may increase customer acquisition costs and the costs of identifying and securing financing, which can further increase the incentives required to encourage new projects. Conversely, simplicity, clarity and predictability of revenues and incentives can reduce customer acquisition costs and the cost of securing financing, reducing the required level of incentive.

Despite the broad range of policy types currently being implemented throughout both the United States and internationally, limited empirical data is available directly comparing the overall cost of different policy and incentive strategies. This report evaluates several potential policy options to support solar development and explores how different incentive program designs might affect overall program costs.

The modeling parameters in this report were developed through both a series of interviews with Massachusetts solar market stakeholders and literature reviews. As with the Task 1 report evaluating incentive requirements under the current policy design, this report evaluates incentive requirements across three project sizes (<15 kW, 15 – 500 kW, and 500 – 6,000 kW), four investor-owned utility service territories (Massachusetts Electric, WMECO, Boston Edison, & Commonwealth Electric), and three ownership structures (private third-party, host, and public ownership).

The report is organized as follows:

- Section 2 summarizes the approach to this analysis including interviews and financial modeling, while Appendix A contains the survey script.
- Section 3 described four policy options examined: an SREC Program with a Soft Price Floor (similar to that in place today, and as analyzed in the Task 1 report); an SREC Program with a Firm Price Floor; a Standard Offer Incentive; and a Competitive Procurement approach.
- Section 4 provides a qualitative competitive analysis of the four policy options.
- Section 5 summarizes the key assumptions used in financial modeling of required incentive levels under the four different policies for the cases examined.
- Section 6 Summarizes the study results for an illustrative subset of the cases examined, while Appendix B contains, in graphical form, the results for the full range of cases modeled for this report.

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[1] New York State Energy Research and Development Authority (NYSERDA). (2012). New York solar study: An analysis of the benefits and costs of increasing generation from photovoltaic devices in New York. Albany, NY

[2] Summit Blue Consulting, & Rocky Mountain Institute. (2007). An analysis of potential ratepayer impact of alternatives for transitioning the New Jersey solar market from rebates to market-based incentives. Boulder, CO: Summit Blue Consulting. Prepared for the New Jersey Board of Public Utilities, Office of Clean Energy

[3] Corfee, K., Rickerson, W., Karcher, M., Grace, R., Burgers, J., Faasen, C., Cleijne, H., Gifford, J., & Tong, N. (2010). Feed-in tariff designs for California: Implications for project finance, Competitive Renewable Energy Zones, and data requirements. Sacramento, CA: California Energy Commission

2 Approach

The analysis contained in this report is centered on an analysis of the levelized incentive required over the life of a 10-year policy duration under different policy approaches. Key inputs – certain transactional 'soft costs' typically included in the installed cost of a system, and the cost of financing – are assumed to vary based on the policy. Available research literature relevant to the topic has been consulted; however, limited published quantitative information is available on the effects of policy structures on financing costs and system soft costs. As a result changes to key modeling input assumptions in this analysis are based largely on a combination of the professional judgment and experience of the authors, and the results of stakeholder interviews. Modeling considered the calculation of the relative level of 10-year incentive under a static set of assumptions corresponding to the applicable policy; a consideration of the sensitivity of the modeling results to the relative importance of the solar incentive; and a translation of the 10-year require incentive to a corresponding SREC floor price.

2.1 Interviews

Interviews were conducted with sixteen Massachusetts solar market stakeholders during May 2013. Interviewees were drawn from a cross-section of industry participants including residential, commercial and utility-scale installers, developers, EPC contractors, analysts, SREC brokers and financiers. The goal of the interview process was to gather both qualitative and quantitative information that would inform the review, analysis and development of potential solar incentive policy options. Interviewees were asked to respond to a series of questions about how critical project financing parameters might differ under a range of specified incentive policy regimes. Interview questions focused on several key project elements including:

- Expectations for project capital structures (debt/equity ratios), and the availability of different types of capital (debt term, availability of tax equity) under each specific policy option;
- Estimates of the cost of financing capital, including project debt, tax equity and sponsor equity;
- Transactions costs including customer acquisition costs and other soft costs.

Appendix A provides the interview script, which was also provided to each participant in advance of the interview. Interviewees provided their reactions to a set of questions under conditions of anonymity.

2.2 Calculating 10-year Levelized Incentive Requirements under a Range of Policy Design options

The evaluation of alternatives to the current policy employs the same methodology as was used and described in the Task 1 Report. Levelized Cost of Energy (LCOE) projections were developed using the National Renewable Energy Laboratory (NREL) Cost of Renewable Energy Spreadsheet Tool (CREST) solar model.[4] The CREST model is designed to calculate the cost of energy, or minimum revenue per unit of production needed, for the modeled renewable energy project to meet its equity investors' assumed minimum required after-tax rate of return. For this analysis, the model

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[4] The CREST model and supporting documentation, developed by Sustainable Energy Advantage, LLC, are available at the NREL web site https://financere.nrel.gov/finance/content/crest-cost-energy-models CREST is a publicly available and transparent tool to aid policymakers in estimating renewable energy costs for various public policy purposes, such as establishing cost-based performance-based incentives such as standard offers.

output has been modified to provide a 10-year levelized incentive requirement rather than a 25-year levelized cost of energy.

A 10-year levelized incentive requirement was calculated for each project category, based on a combination of the installed cost trajectories developed as part of Task 1 – adjusted to reflect expected differences in acquisition costs, transaction costs and other soft costs between the policy designs – and the financing assumptions developed through the interview and literature review process. These assumptions are presented in Section 5.1.1. For all other inputs, this analysis utilizes the same modeling assumptions as the Base Cost Case, NM-No Cap from the Task 1 Report.

As with Task 1, the CREST model incorporates the market value of electricity sales, and solves for the minimum *additional* 10-year levelized revenue required to achieve the specified project's defined after tax return on invested capital.

2.3   Sensitivity of Results to Importance of Solar Incentive

It is important to note that the SREC incentive provided through the policy alternatives discussed in this section make up only a part of the total revenues of a PV system. The modeling performed in this analysis assumed static differences in financing costs and other soft costs between policy options regardless of the total relative contribution of SRECs to the entire project cash flow. It should be noted; however, that this approach is a necessary modeling simplification of expected real-world market performance. In instances where SREC incentive requirements approach zero (as PV system costs decline and revenues from non-SREC sources increase) the overall importance of the SREC incentive will decline and differences in required incentive between policy types are also likely to decline. This phenomenon is discussed in more detail in Section 6.3.

2.4   Translation of Required 10-year Incentive into SREC Floor Prices

In the case of a standard offer or competitive procurement for a fixed-price (S)REC contract, the incentive is known. In contrast, in the case of a SREC policy with a floor, the required incentive is not equivalent to the floor price; the floor price will be lower, because there is 'upside' up to the price cap (Alternative Compliance Payment) level. This analysis modeled an investor/developer perspective on projected market revenues under an SREC with price floor policy in order to estimate an SREC Factor (a decimal representing the number of SRECs conveyed to the project for each MWh generated) necessary to provide the target revenues for a specified schedule of declining ACP and auction floor levels. This analysis was conducted using a set of reasonable assumptions to translate the required incentive into an SREC Factor (along with other policy parameters) expected to produce an equivalent value, and to examine the relationship of the level of the SREC Factor to the firmness of the floor price.

3 Modeled Policy Options

Three alternative policy options were considered and modeled as part of this Task 2 Report in addition to the current solar carve out policy reviewed in Task 1 of this analysis. All four policies are listed and described below.

1. SREC Program with a soft price floor (as modeled in Task 1)
2. SREC Program with a firm price floor
3. Standard offer incentive
4. Competitive procurement (for fixed price SREC contract)

3.1 SREC Program with a Soft Price Floor

This policy option describes the current Massachusetts SREC program and served as the base policy scenario for the analysis performed in Task 1 of this report. Key policy elements include:

i. a formula-adjusted demand target that must be met annually by load-serving entities by procuring SRECs;
ii. specified alternative compliance payments serving as a cost cap;
iii. a fixed duration of SREC eligibility (i.e. 10 years) followed by Class I REC eligibility for the remainder of the project life; and
iv. spot market trading for SRECs, supported by an SREC clearinghouse fixed-price auction.
v. The price floor would not be considered firm as no creditworthy entity would be guaranteed to purchase unsold SRECs in the auction, and SRECs deposited in the auction may not yield revenues until up to a few years later.[5]

3.2 SREC Program with a Firm Price Floor

This policy option is similar to the existing SREC program. The auction mechanism would be amended, however, to include a requirement that a creditworthy entity purchase all excess SRECs in the event that the auction does not clear. The price floor would be firm, fixed and published for all market participants on an annual basis. The floor price is assumed to be set at a level sufficient – when combined with the 'upside' of revenues (in some years) above the floor - to enable project investors to realize their minimum return requirements.

3.3 Standard Offer Incentive

Key elements of this policy option include:

i. guaranteed access to a long-term SREC contract with a distribution utility or other credit-worthy counterparty;
ii. fixed SREC prices established in advance through an administrative process;
iii. a predictable schedule on which incentives might be adjusted (for new market entrants), which may be based on total installations and/or other market-based triggers; and
iv. no competitive bidding process.

3.4 Competitive Procurement (for fixed price SREC contract)

The final policy option evaluated was a competitive procurement. This incentive program structure has the following features:

i. periodic competitive solicitations, with minimum bid eligibility criteria;
ii. price and non-price evaluation and selection criteria;
iii. for selected projects, procurement of SRECs under long-term contract with a distribution utility or other credit-worthy counterparty;
iv. contracts executed through a utility (or utility-backed) auction or single-bid solicitation process; and
v. in the competitive procurement model, contracts could be offered/awarded to winning bidders at the bid price, at a clearing price, or at another auction-derived price.

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[5] http://www.mass.gov/eea/docs/doer/rps-aps/225-cmr-14-00-draft-reg-doer-041213.pdf

4 Qualitative Analysis of Policy Options

This section provides a qualitative review of the policy options evaluated in this report. The analysis was informed by literature reviews and the perspective of interviewees consulted for this project.

4.1   Policy Options Analysis

4.1.1   SREC Program with a Soft Price Floor

Without the statutory means to designate a creditworthy buyer of last resort to firm the price floor or tender a standard offer, DOER has to date been limited in the incentive structure options at its disposal. Based on progress to date and the ample pipeline of projects seeking to qualify, the current Massachusetts SREC market structure has proven effective in supporting a robust solar development pipeline. The rapid growth of the market suggests that this policy option has been an effective tool to meet many of the state's policy goals including renewable energy targets, workforce development, greenhouse gas reductions and re-use of contaminated lands. Additionally, the current incentive structure (in concert with co-policies, particularly the Massachusetts Clean Energy Center's Commonwealth Solar II Program) has led to the development of a diverse range of project types, from landfill-sited large ground mount systems to residential rooftops, suggesting a program that is available to a broad range of the ratepayers that ultimately fund the program.

While the SREC Floor combined with the supply-driven demand obligation formula has prevented SREC prices from crashing in the presence of surplus, the floor has not proven to be firm, with market SREC prices falling below $285 per SREC for much of the program's recent history and the 2013 auction failing to clear. The SREC market structure allocates this SREC price risk to project owners, the impact of which is described further below. However, one substantial benefit of the current SREC market structure is found in its risk allocation. It allows ratepayers to benefit from falling solar costs. While under a standard offer incentive, if the installed costs of solar PV were to fall sharply, SREC prices ultimately paid for by ratepayers would not drop, the current SREC policy structure would allow SREC prices to fall.

Despite the success of the current incentive structure in rapidly growing a robust pace of development across a diverse mix if project types, stakeholders involved in project development and financing report that the current incentive structure presents several barriers to obtaining low-cost debt financing that would lower both project and overall policy costs. The complexity of the program and the substantial uncertainty around future SREC prices has limited the availability of debt financing in the Massachusetts market. Stakeholders report that lender education is challenging and that financiers may be unwilling to invest the time necessary to fully understand the market given the relatively small size of the Massachusetts SREC program. Stakeholders also report that, when lenders are willing to support projects, they do so for a smaller portion of total project costs than they might in other states with different policy regimes, leading to lower project debt-to-equity ratios. Equity is generally more expensive than debt and a lower debt-to-equity ratio typically means that the cost of capital will be higher overall. This, in turn, means that projects will require higher incentives in order to be successfully financed and constructed.

The limited number of lenders willing to provide capital for Massachusetts solar projects may also present a barrier to entry for new market participants. Many of the successful developers in the state have financial backing from well capitalized corporate parent companies. Without ready access to capital, smaller local enterprises report the challenge of competing with national solar developers.

The complexity and risks associated with the Massachusetts incentive program may also drive an increased prevalence of third-party owned systems while also increasing overall customer acquisition costs. Prospective system owners may

not be willing to take the time to fully understand the nuances of the Massachusetts SREC market, making third-party ownership models more attractive given the benefits of allowing the third party owner to take on the risks associated with the SREC market and navigate the process of monetizing credits.[6] Given these factors, customer acquisition costs, costs of arranging financing and costs to apply for incentives may be higher for this policy option than for others evaluated in this report.

4.1.2   SREC Program with a Firm Price Floor

An SREC program with a firm price floor may mitigate some of the challenges which stakeholders identified in association with the current program. Stakeholders generally had a favorable opinion of this option and noted that bank financing could be more readily accessible under this policy regime.

Requiring a creditworthy entity, such as a regulated distribution company, to purchase SRECs out of the annual auction (or through a similar mechanism) would likely increase the availability of lower-cost bank debt for solar projects in Massachusetts. Firming the auction floor price and off-take would effectively create the equivalent of a long-term SREC contract with a creditworthy counterparty (albeit, one in which the project owner would get additional 'upside'). This policy mechanism would significantly increase the portion of total project cash flow that potential financiers might deem bankable, raising project debt to equity ratios.

While most stakeholders felt that this policy option was an improvement of the existing SREC program, some expressed concerns about the regulatory risks associated with such a strategy. It was noted that, depending on how the policy was structured, future legislation or regulatory changes could nullify the requirement for a creditworthy entity such as the EDCs to purchase SRECs at a fixed floor price. If the auction price floor does not constitute a sufficiently binding obligation, the potential that the auction purchase requirement could be eliminated legislatively creates risk for project investors and owners. This type of regulatory risk may cause financiers to discount future SREC values below the administratively established SREC auction floor. Other commenters noted that this policy approach could provide SREC generators with significant added revenue at ratepayer expense despite the substantial reduction in financial risk associated with firming the SREC auction floor. One approach to mitigating the potential for projects to capture excess profits would be to lower the SREC ACP payments to a level that is closer to the price set for the auction floor; alternatively, DOER could convey fewer SRECs through its 'adjusted SREC factor' approach.[7]

It is estimated that an SREC program with a firm auction floor would lower the time and effort required to identify sources of funding and close project financing. With the added certainty of the auction floor, more lenders – and equity providers – would likely be willing to participate in the Massachusetts market. The presence of more financiers in the market could increase investment competition and lead to a lower cost of financing capital available to individual projects. Increased competition could also reduce the effort required by developers to secure financing. While more complex than other policy options reviewed for this study, the SREC program with a guaranteed buyer of last resort is simpler than the existing auction mechanism, creates greater certainty and may require less investor education.

Customer acquisition costs under this model are anticipated to be slightly lower than under the current policy because of the simplified auction mechanism. Prospective system owners may not have an interest in understanding the

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[6] DOER has noted that one policy goal of the Post-400MW program is to increase the proportion of PV systems installed under the direct ownership model given the expected benefits to the Massachusetts economy compared to third-party ownership. The incentive requirements presented in Section 6 of this report enable a comparison of the potential costs and benefits of third party ownership, host ownership and public ownership.

[7] For more on the adjusted SREC factor see: http://www.mass.gov/eea/docs/doer/rps-aps/doer-post-400-mw-solar-policy-design-stakeholder-review-mtg-060713.pdf

complexities of Massachusetts SREC regulations and, under this policy regime, PV developer sales teams may be able to provide a streamlined description of the expected SREC incentive without risking confusing or misinforming potential system owners (as well as being able to guarantee a minimum revenue, a prospect not possible today). This would likely lead to lower customer acquisition costs compared to the current SREC program.

Given that this policy design would be substantially similar to the current program in terms of how project owners would monetize their SRECs, it is unlikely that administrative costs associated with the program would be materially different from the current SREC program. As a result, administrative costs were modeled as unchanged from the current SREC program.

4.1.3 Standard Offer Incentive

A standard offer is conceptually a challenging philosophical fit in Massachusetts' competitive retail electricity market structure, under which the electric distribution company's role is primarily that of delivery of supply, and customers can choose from competitive retail electricity providers. Nonetheless, the standard offer policy option was viewed by many of the interviewed stakeholders as a preferred policy option given its simplicity, its lower development risks, and it's potential to attract lower cost capital. While many of these stakeholders looked favorably on this option, there was concern as to whether this could be implemented under the legislative framework through which DOER has developed the existing solar incentive program, how long such implementation might take, and how the market would sustain itself during a transition.

A Standard Offer program presents a number of potential advantages with respect to financing solar projects. With a bankable long-term SREC contract, project developers may be more likely to be able to add substantial bank debt into their project capital structures, lowering overall project revenue requirements as well as overall policy costs. Access to a known price ahead of time also eliminates the risks that developers face when they must compete based on price before project costs are fully known. Well-structured standard offer programs with clear price adjustment schedules can also provide market participants with transparency and certainty about future incentive values, and allow them to make longer term resource allocation decisions. Additionally, standard offers structured as long-term contracts can provide legal recourse in the event that incentive payments should change or be disrupted during the system's life. This benefit is not available for incentive structures that rely on auctions with prices floors.

As with all administratively-determined incentives (e.g. rebates and tax credits), standard offer incentives must be balanced in order to stimulate market growth and achieve state policy objectives, while not allowing PV developers, financiers or installers to capture excess profit. Administrative rate setting may also require lengthy regulatory proceedings that may make it challenging for incentive levels to keep pace with rapidly changing market conditions. This can be mitigated, however, through the use of automatic (e.g. volume-based) adjustment mechanisms and/or through the ability of regulators to act in a streamlined fashion to make incentive changes. There are tradeoffs, however, between the ease with which regulators can intervene and the stability and transparency of the market.

In addition to the potential reduction in overall project financing costs, standard offer incentive programs are also likely to have a lower cost of acquiring financing. A long-term contract with a credit worthy off-taker at a price know in advance would likely be an incentive structure that could be easily understood by lenders, resulting in lower labor expenditures to obtain financing. Standard offers may effectuate programmatic (rather than project-by-project) financing, with a greater degree of standardization leading to lower overall financing costs. The simplified structure of a standard offer incentive program might also be easier to market to potential system owners, leading to reduced customer acquisition costs.

Finally, of all the policy options considered in this Report, administrative costs to apply for and receive the incentive are likely to be the lowest for the standard offer incentive structure. Any standard offer program would likely also not require brokers or other intermediaries to monetize the incentives, resulting in a lower overall policy cost.

4.1.4 Competitive Procurement

Interview respondents generally did not favor the competitive procurement policy. Several installers felt that this policy option greatly favored larger developers with the ability to devote resources to developing multiple projects and take the risk that some projects would not receive incentives. While the risk of not being selected would present barriers for project developers, interviewees generally felt that, after contracts were awarded, this policy would likely be very similar to the standard offer policy with respect to the assumed parameters for permanent financing. Debt to equity ratios are expected to increase, and costs of capital are expected to decrease compared to either of the market-based SREC approaches, given the certainty provided by a long-term contract with a utility offtaker. Having such a contract would likely allow project developers to better access bank debt, potentially lowering overall required solar incentives.

One theoretical benefit of competitive procurement incentive mechanisms is that they combine a competitive market-based incentive pricing mechanism (the auction) with a guaranteed, long-term incentive contract. This combination of strategies could, in theory, produce a low-cost policy by both allowing access to cheaper capital and ensuring that incentives are only awarded to the most competitive projects. Despite these theoretical benefits, competitive procurement-based incentives have faced significant contract failure rates, with developers in some programs frequently failing to meet project development milestones, eventually resulting in abandoned contracts.[8]

Customer acquisition costs for the competitive procurement policy were modeled as significantly increased for large system sizes, as developers would likely need to sell multiple projects in order to have a single project win a solicitation. Developers and installers report significant challenges in aligning projects hosts under this approach, as the sale process is ultimately conditioned on a winning bid, a frustration to the host which represents a barrier to doing business. Given the complexity of this incentive policy, it is unlikely that it would be appropriate for residential-scale systems; however if residential developers were able to bid in a portfolio of prospective projects, this approach could result in lowered overall customer acquisition costs for a large-scale residential developer.

In addition to likely higher customer acquisition costs, the competitive procurement policy was expected to result in higher administrative costs related to incentive applications. As with the customer acquisition category, project developers would likely need to complete several bids in order to be awarded a single project. Finally, costs related to arranging financing are expected to be lower for this policy option than for the SREC policy options, as project developers would have long-term incentive contracts in hand when approaching permanent financing partners. This soft cost would likely not be as low as in the standard offer case as the competitive procurement policy could require some effort to work financiers in advance of the solicitation process.

4.2 Other potential policy variations

While the four policy designs described in this Report represent a range of viable options for balancing market development and ratepayer cost, potential variations on these themes also exist and may provide additional benefits to solar market participants, consumers, or both. Two examples of such variations are provided below.

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[8] Wiser, R., O'Connell, R., Bolinger, M., Grace, R., & Pletka, R. (2006). Building a "margin of safety" into renewable energy procurements: A review of experience with contract failure. Sacramento, CA: California Energy Commission.

4.2.1 Incentive Duration

For all policy options, increasing the duration of the contract (or other incentive) from 10 years (as in the current policy) to 15 or 20 years will have a material impact on both financing options and overall project and ratepayer cost. Creating revenue certainty for a longer period of time is likely to increase the term of the loan offered by banks and increase the amount of money that the bank is willing to lend to a specified project (as a percentage of the project's total cost). Both of these changes will exert downward pressure on the project's levelized cost of energy and required incentive payment because cheaper debt will comprise a larger portion of the capital structure than equity and will be amortized over a longer period of time. Renewable energy facilities that do not rely on fuel are ideally situated to capture these benefits for ratepayers.

4.2.2 Bundled Energy and SREC Contracts

While the standard offer policy evaluated as part of this report assumed long-term contracts for SRECs separate from sales of electricity via net metering credits or wholesale sales, it should be noted that policies – including standard offers – can also be structured to pay for both electricity and SRECs bundled under a single contract. Market electricity revenues are difficult to hedge at their full expected value, particularly over the term of a PV project's life. As a result, developers may have to either build a margin of uncertainty into their financial pro-formas to account for the uncertainty of future wholesale or retail electricity sales (or net metering), or enter a long-term sale agreement for energy at a discount to the expected market value. Standard offer programs that provide incentives for both the value of delivered energy as well as a solar price premium may be an attractive policy option, particularly as net metering policies in Massachusetts have legislative limits that are expected to be reached during the period of this analysis.

5 Key Assumptions

In general, market participants were eager to participate in the interview survey and provide feedback on their experience with the current market structure. While interviewees provided a large amount of qualitative insights into the key survey questions, the interview process resulted in a much more limited set of quantitative information that could be used to inform the key financial modeling parameters. The following section highlights feedback from interviewees on each of the proposed policy options. Based on this feedback, a complete set of financial modeling parameters was developed and used to evaluate potential differences in required incentives.

5.1 Effects of Policy Options on Capital Costs and Availability

Interviewees had a range of opinions on the cost of financing capital and capital structures being deployed under the current incentive program. With a few caveats, interviewees expected the cost of capital to be similar for the standard offer, competitive procurement, and SREC market with price floor policy options. While opinions varied, developers, installers and financiers also noted that certain types of capital may not be available (i.e. bank debt or tax equity) under the current SREC program.

The existing SREC program was perceived to be far more risky than any of the alternatives when considered from the financiers' perspective. This means that fundamentally different capital structures and market participants would be

expected to participate compared to other incentive program designs. This viewpoint is consistent with literature on the topic, which has found that less certain revenue streams lead to higher costs of capital and higher policy costs.[9]

Responses to questions on the availability and cost of capital in the current SREC program without a firm floor are detailed below. Depending on the stakeholder's strategy in the Massachusetts market, interviewees focused on either non-recourse project finance[10] or on financing models under which debt would be secured using the project owner's balance sheet. Comments are divided below between those two project funding methods.

Comments on Project Finance
- Generally, developers and financiers noted challenges with obtaining bank debt for project finance transactions under the current SREC market structure.
- One developer reported that bank debt was available, but that banks would only underwrite cash flow derived from net metering credit arrangements (which may include direct savings to the project host or contractual payments by the host customer to a third-party developer.
- One developer that has been able to access bank debt for Massachusetts projects noted that policy regimes in other states allow them to incorporate twice as much bank debt in a project capital stack.
- A major national tax equity provider reported that they were unwilling to participate in the current Massachusetts market given perceived regulatory risks.

Comments on Corporate Finance

- A few developers reported having had success in educating local lenders about the program and obtaining debt for projects.
- Several active large system developers were able to obtain debt financing based on the balance sheets of their corporate parent company – rather than on projected project revenue.
- Traditional home equity loans are a viable and low-cost option for homeowners that can obtain financing, however these projects are not evaluated, and debt is not priced, based on project cash flow.
- Commercial owners that are interested in pursuing direct ownership may be able to work with local lenders to obtain financing, however, as with residential home equity financing, lenders are unlikely to evaluate project cash flows in loan pricing

Comments regarding financing costs for the SREC program with a firm price floor, standard offer and competitive procurement included:

- Interviewees felt that, in general, a contract either through a standard offer or a competitive procurement would be bankable and would be able to command lower costs of debt and equity than the current program. An SREC market with a guaranteed price floor was expected to have a similar effect – although possibly to a lesser degree given the perceived continuance of regulatory risk.
- One financier noted that the greatest effect on capital structure and cost of financing would be the ability to access longer-tenor debt and the effect of these policies on debt interest rates would be less pronounced.

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[9] DB Climate Change Advisors. (2009). Paying for renewable energy: TLC at the right price - Achieving scale through efficient policy design. New York, NY: The Deutsche Bank Group; Baratoff, M. C., Black, I., Burgess, B., Felt, J. E., Garratt, M., & Guenther, C. (2007). Renewable power, policy, and the cost of capital: Improving capital market efficiency to support renewable power generation projects. Ann Arbor, MI: University of Michigan, Erb Institute for Global Sustainable Enterprise. Prepared for UNEP/BASE Sustainable Energy Finance Initiative.

[10] PV projects structured under traditional project finance models provide no recourse the project LLC's parent company.

- More than one developer felt that the SREC program with firm price floor could have more regulatory risk than either the standard offer or competitive procurement policy options, potentially resulting in a cost of capital higher than the two other designs.
- A developer argued that an SREC market with a firm floor would lower financing costs but would not lower ratepayer costs as much as the other firm contract policy options because it leaves significant upside potential for SREC sellers

5.2 Financing Modeling Assumptions

The following financing parameters were used to estimate the required incentive. First and foremost, this Task 2 analysis uses as a starting point all of the modeling assumptions employed in the Base Cost Case analysis from Task 1. If a modeling input is not specifically defined in this section, the reader should assume that the input remains unchanged from Task 1. The market segments analyzed in this Report are also the same as in Task 1, and are summarized in Table 1 below.

Table 1: Project Categories by Market Segment, Defined by Size and Installation Type

Market Segment	Installation Type/ Land Classification	Project Size Range (kW)	Representative Size for Modeling Purposes (kW)
Residential	Roof	< 15	5
Commercial	Roof/Ground	15 – 500	250
Large Scale Ground-Mounted	Ground (Greenfield)	500 – 6,000	1,500
	Landfill	500 – 6,000	1,500

The incentives required for each of the categories defined in Table 1 were tested under private third-party and host ownership models for each policy design option. The non-residential categories were also tested under a public ownership option, in which the project was assumed to be financed through a 20-year municipal general obligation bond.

The need for and magnitude of potential incentives was evaluated under the three potential program design options described in Section 4 and compared to the solar carve-out SREC with soft floor approach described and evaluated in the Task 1 Report. Table 2 through Table 4, below, show the financing assumptions employed in this analysis under each potential program design and ownership option. For all three ownership options, the financing assumptions for Standard Offer are the same as for Competitive Procurement. Customer acquisition costs, transaction costs and other soft costs are assumed to vary between these options, however, and are explained in Section 5.3. The financing assumptions from Task 1 are also included for comparison to alternative policy approaches.

Table 2: Financing Assumptions for Each Program Design under Third-Party Ownership

	SREC w/ Soft Floor			SREC w/ Firm Floor			Standard Offer & Competitive Procurement		
	Roof	Roof or Ground	Ground	Roof	Roof or Ground	Ground	Roof	Roof or Ground	Ground
	<15	15 - 500	500+	<15	15 - 500	500+	<15	15 - 500	500+
Debt									
% Debt	30%	30%	30%	40%	40%	40%	50%	50%	50%
Debt Term	5	5	5	7	7	7	10	10	10
Int. Rate	6%	6%	6%	5.5%	5.5%	5.5%	5%	5%	5%
Equity									
With ITC	15%	15%	15%	13.3%	13.3%	13.3%	12.3%	12.3%	12.3%
Post-ITC[11]	12%	12%	12%	10%	10%	10%	9%	9%	9%

Third-party financing assumptions are based on stakeholder interviews and other research conducted in conjunction with this Report. As demonstrated in Table 2, the amount of debt available to a project is expected to increase as revenue certainty increases and lenders are able to size loans based on both net metering credits and SRECs. Of potentially greater importance, loan tenors are also expected to extend when incentives are guaranteed for longer periods of time. The longer amortization schedule, if available, creates a meaningful reduction in the project's LCOE and the 10-year levelized incentive requirement. Interest rates are assumed to decrease slightly as SREC price risk is reduced, but are not expected to play as significant a role in cost reduction as the increase in leverage and term. Finally, the third-party ownership structure is unique in its consideration of the impact of tax equity investors and the Investment Tax Credit (ITC) on the cost of equity. During the period in which the ITC is in place (through December 31, 2016), projects are modeled assuming 66% of equity investment from a tax equity investor and 34% from the project sponsor (developer). After the ITC expires, the pool of available capital is expected to increase, and competition is assumed to drive down the cost of equity. As policy design increases revenue certainty, the cost of equity (both with and without the ITC) is reduced further.

Table 3: Financing Assumptions for Each Program Design under Host Ownership

	SREC w/ Soft Floor			SREC w/ Firm Floor			Standard Offer & Competitive Procurement		
	Roof	Roof or Ground	Ground	Roof	Roof or Ground	Ground	Roof	Roof or Ground	Ground
	<15	15 - 500	500+	<15	15 - 500	500+	<15	15 - 500	500+
Debt									
% Debt	40%	40%	40%	40%	40%	40%	50%	50%	50%
Debt Term	15	15	15	15	15	15	15	15	15
Int. Rate	4%	6%	6%	4%	5.5%	5.5%	4%	5%	5%
Equity									
Target IRR	4%	12%	12%	4%	10%	10%	4%	8%	8%

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[11] This assumes that a sunset of the ITC eventually results in access to a larger pool of less expensive investment capital.

In the host ownership case, the amount of debt available is assumed to be based on cash flows available for debt service and the expected loan term. In this case, a creditworthy host is assumed to be able to combine the 10-year SREC incentive and long-term net metering benefit with its corporate credit to secure a 15-year loan. Interest rates are expected to decline as the perception of revenue certainty increases. With respect to equity, a corporate discount rate is estimated, and is also assumed to decline as revenue certainty increases. Roof-mounted host-owned projects describe installations owned by homeowners. In this case, the cost of both equity and debt are based on long-term end user borrowing rates.

Table 4: Financing Assumptions for Each Program Design under <u>Public Ownership</u>

	SREC w/ Soft Floor			SREC w/ Firm Floor			Standard Offer & Competitive Procurement		
	Roof	Roof or Ground	Ground	Roof	Roof or Ground	Ground	Roof	Roof or Ground	Ground
	<15	15 - 500	500+	<15	15 - 500	500+	<15	15 - 500	500+
Debt									
% Debt	N/A	100%	100%	N/A	100%	100%	N/A	100%	100%
Debt Term	N/A	20	20	N/A	20	20	N/A	20	20
Int. Rate	N/A	4%	4%	N/A	4%	4%	N/A	4%	4%
Equity									
	N/A	4%	4%	N/A	4%	4%	N/A	4%	4%

In the public ownership case, the financing parameters are not varied by policy design option. This modeling choice is based on the assumption that the availability of bond financing will be project- and borrower-specific, and that while the incentives and certainty offered by different policy designs is likely to impact whether or not financing is <u>available</u> to a publicly owned project, it is not likely to influence the cost, duration or other terms of such a loan.

5.3 Effects of Policy Options on Soft Costs

Interviewees were also asked to comment on the perceived effect of different policy options on certain 'soft' costs. In general, these comments related to two categories of transaction costs: customer acquisition costs and costs to obtain financing. While interviewees noted that these costs would differ under different policy options--and were generally in agreement on how a particular policy might affect a cost category--interviewees were generally unable to provide quantitative estimates of how policy changes would affect these costs. Comments from the interviews are discussed below.

5.3.1 Customer acquisition costs:
- One residential installer focused on selling direct-ownership systems noted that explaining the current SREC program to potential customers was challenging and added to the complexity of selling systems under the direct ownership model when compared to third-party ownership.
- Multiple interviewees felt that competitive procurement substantially increased customer acquisition cost as multiple projects would need to go through the sales process in order to yield a single project. This was also perceived as a barrier to market entry for certain types of customers.

5.3.2 Financing transaction costs:

- One finance expert suggested that up to four lenders might be need to approached in order to find one willing to finance a Massachusetts solar deal under the current SREC market structure.
- Another noted that the current policy requires significant lender education, raising transaction costs for this policy option over other, less complex policy options

5.4 Transaction Cost Modeling Assumptions

Data for average customer acquisition and financing transaction costs are not available for the Massachusetts market. However, a national study of these and other soft cost has been conducted by NREL that estimated average soft cost as a percentage of installed system costs.[12] Table 5 below shows the estimated customer acquisition costs and financing transaction costs, as a percentage of total installed cost, found through this national survey. The table also shows estimated labor costs of incentive applications for each system size class.

Table 5. Average Cost of Transaction Cost Category as a Percentage of Installed Cost

	Customer Acquisition	Financing Labor	Incentive Application Labor
Residential	10%	0.3%	0.4%
<250kW	3%	0.3%	0.1%
>250kW	1%	0.2%	0.02%

These national average percentages were applied to the system installed costs projection for each system size used in the Task 1 analysis in order to derive an estimate $/Watt cost value for each soft cost category. Based on stakeholder feedback and assumptions developed by the authors, a multiplier was developed for each of the policy options and soft cost categories. This policy costs multiplier was applied to the base policy system soft cost to derive expected system costs under the alternative policy regimes. For instance, stakeholders reported that customer acquisition cost would likely rise under a competitive procurement, as some developers would need to enter multiple systems it an auction in order to have a single system awarded incentives. Given this higher costs, it was estimated that customer acquisition costs could rise by a factor of three for commercial scale system under a competitive procurement policy. Table 6 below shows the policy cost multipliers that were used for this analysis.

For customer acquisition costs in the SREC with Soft Floor, SREC with Firm Floor and Standard Offer cases, it was assumed that the time and effort required to sell a PV system would decline as the complexity and revenue risk associated with the incentive program was reduced. PV developers would need to spend less time educating consumers about the SREC market in order to make a sale as risk and complexity were reduced. For the Competitive Procurement case, it was assumed that for large systems, a developer would need to sell three systems in order to build a single project as projects that had been fully sold would not be guaranteed an SREC contact. For the residential Competitive Procurement case, it was assumed that residential developers would participate in this type of program using a portfolio approach that would allow them to bid in a tranche of systems at a single SREC price. This could lead to lowered

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[12] Ardani, K., Barbose, G., Margolis, R., Wiser, R., Feldman, D., Ong, S., (2012) Benchmarking Non-Hardware Balance of System (Soft) Costs for U.S. Photovoltaic Systems Using a Data-Driven Analysis from PV Installer Survey Results. Golden, CO; National Renewable Energy Laboratory.

customer acquisition costs due to the aggregated nature of the procurement and the benefits of selling a known long-term contract price to potential system owners.

For the financing labor soft cost category, it was assumed that developers would be required to put more effort into educating potential financiers of the market nuances of the SREC with Soft Floor than of other policies. It was assumed that adding a firm price floor would lower this effort as financier without in-depth understanding of the policy could simply lend on the basis of the firm floor price. The Standard Offer policy case had the lowest financing labor costs as this policy would require limited financier education and would likely be perceived as more attractive to debt providers. The competitive procurement was modeled to have a moderate increase in labor financing costs over the Standard Offer as the uncertainty of winning a competitive procurement would require more effort to find and educate lenders.

Incentive application labor was assumed to be equal for both the SREC with Soft Floor and SREC with Firm Floor cases. Monetizing a standard offer was assumed to be a simpler process requiring less effort than either of the SREC market-based mechanisms. Finally, the requirement of submitting multiple bids in order to win a single project raised the expected effort required under the competitive procurement case.

Table 6. Policy cost factors used for sensitivity analysis

	Customer Acquisition	Financing Labor	Incentive Application Labor
SREC w/ Soft Floor			
<15 kW	1	1	1
15-500	1	1	1
500-6000	1	1	1
SREC w/ Firm Floor			
<15 kW	0.8	0.7	1
15-500	0.8	0.7	1
500-6000	0.8	0.7	1
Standard Offer			
<15 kW	0.7	0.5	0.75
15-500	0.7	0.5	0.75
500-6000	0.7	0.5	0.75
Competitive Procurement			
<15 kW*	.75	1	3
15-500	3	0.7	3
500-6000	3	0.7	3

* Residential customer acquisition costs for the competitive procurement could vary widely based on whether the developer was submitting a portfolio of projects or a single project

For illustrative purposes, Table 7 below shows representative costs for each of the policy cases for the 15-500 kW rooftop installation class after applying the policy costs multipliers. Installed costs for other market segments were adjusted in a similar manner using the factors in Table 6. The first row figures are the same as those uses in Task 1. These costs were used as inputs into the CREST model sensitivity analysis.

Table 7. 15-500 kW System Size Class Installed Costs by Policy Type

	2013	2014	2015	2016	2017	2018	2019	2020
SREC w/ Soft Floor	$4.13	$3.87	$3.63	$3.42	$3.24	$3.07	$2.92	$2.78
SREC w/ Firm Floor	$4.09	$3.84	$3.60	$3.40	$3.21	$3.04	$2.89	$2.76
Standard Offer	$4.08	$3.82	$3.59	$3.38	$3.20	$3.03	$2.88	$2.75
Competitive Procurement	$4.36	$4.09	$3.84	$3.62	$3.42	$3.24	$3.09	$2.94

6 Results

6.1 Impact of policy options on required incentive

This analysis utilizes the financing and soft cost adjustments described in Section 5 to evaluate the expected 10-year levelized incentive requirement for each market segment, in each of the four modeled utility service territories, in three ownership scenarios, under three alternative policy designs. As described in Section 2.1, the CREST model output has been modified to provide a 10-year levelized incentive requirement rather than a 25-year levelized cost of energy.

Figure 1 through Figure 4 provide an illustration of the modeling projections for private third-party owned projects in the Massachusetts Electric (National Grid) service territory. The 10-year levelized incentive requirements (in $/MWh) for each of the four policy designs (including the SREC with soft floor) are compared on a single graph. Each market segment has its own graph. Appendix B provides a complete set of results for all market segments, utility service territories and ownership structures.

Figure 1: Incentive Requirement: Mass Electric (National Grid), Roof Mounted < 15 kW Residential, 3rd-Party Private Ownership
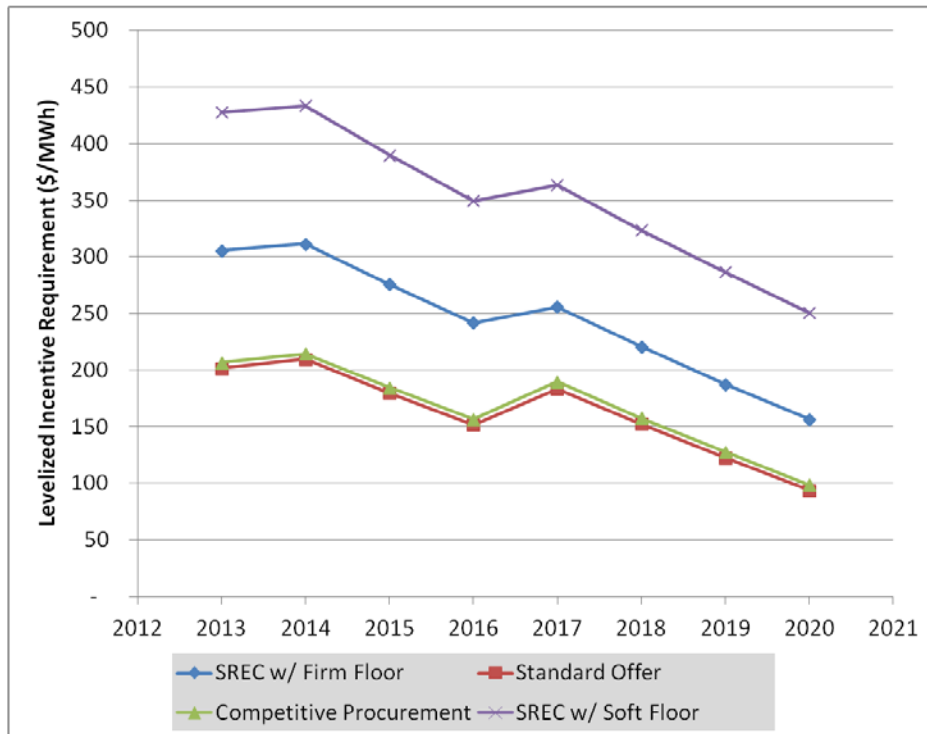
Figure 2: Incentive Requirement: Mass Electric (National Grid), Roof Mounted 15-500 kW, 3rd-Party Private Ownership
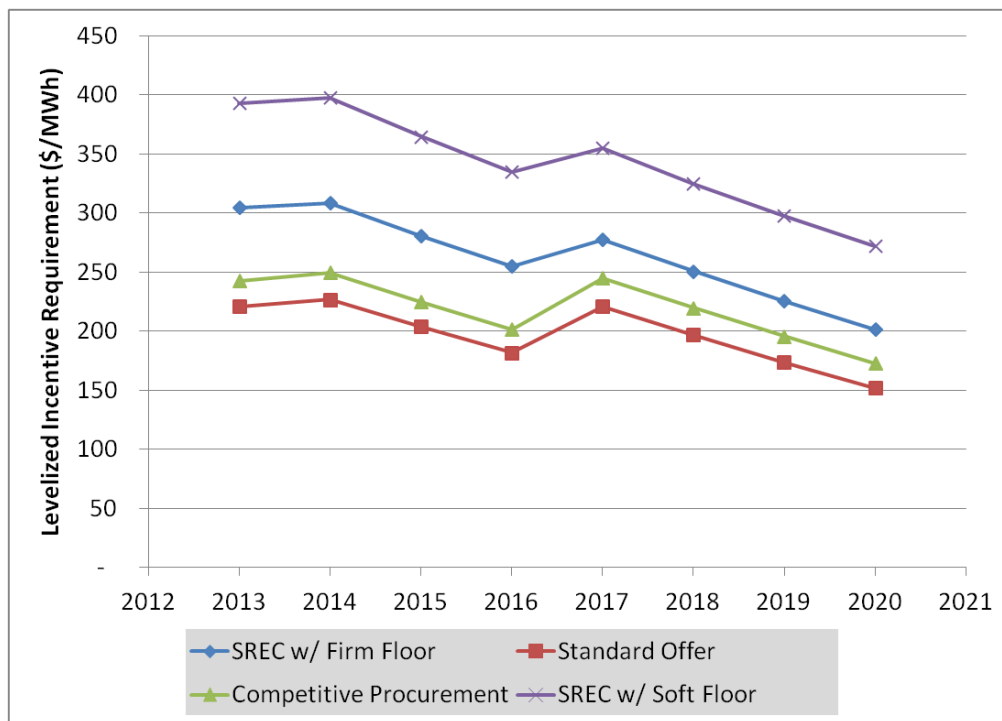
Figure 3: Incentive Requirement: Mass Electric (National Grid), Ground Mounted 500+ kW, 3rd-Party Private Ownership
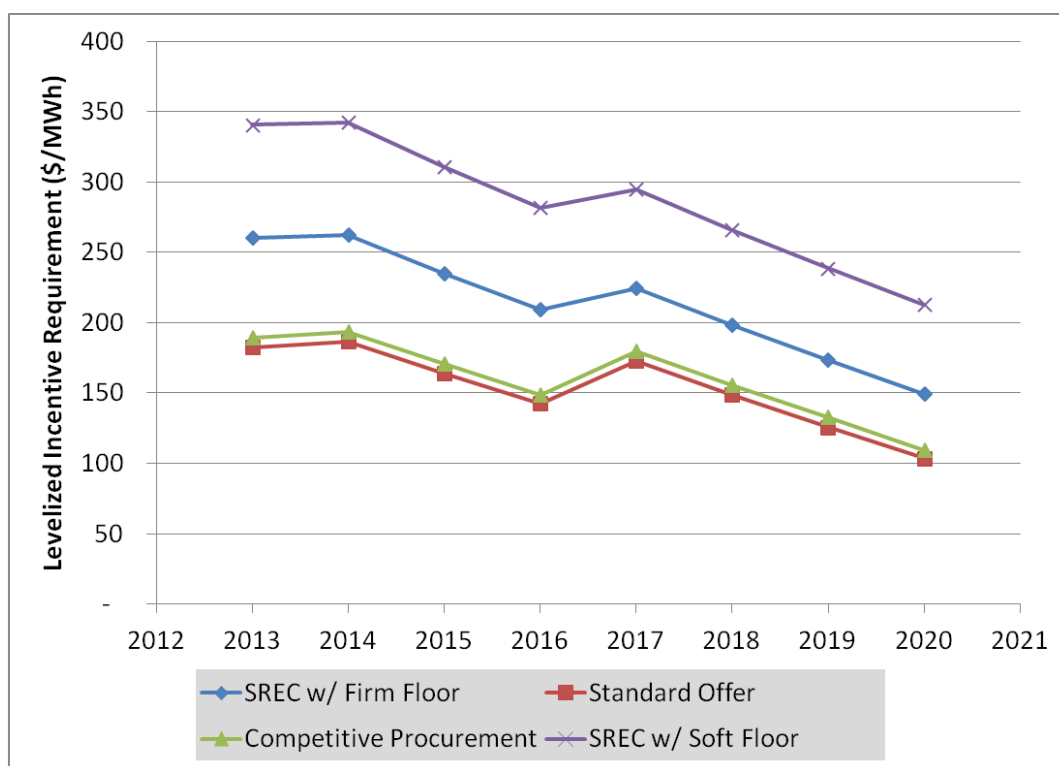
Differences in incentive levels between the policies are driven by a combination of assumed impacts on both financing costs and certain transaction cost. As might be expected, the more reliable the revenue stream, all else equal, the lower the incentive required. A firm floor added to the SREC policy reduced risk, financing costs and transaction costs, and therefore would be expected to yield lower incentive requirements. Further advantages in financing cost and transactions costs are expected to apply to the standard offer and competitive procurement options, although the greater transaction costs associated with competitive procurement are expected to yield slightly higher incentive requirements than the standard offer.

6.2   Limitations of 10-Year Levelized Incentive Analysis

The results of this analysis should be evaluated alongside several important caveats. For instance, while the directional differences between required incentives under different policy conditions are consistent with expected outcomes, there is limited literature to confirm the magnitude of these results. Stakeholders who are actively participating in multiple state solar markets with policies that are similar to some of those modeled in this report were unable to consistently provide quantitative estimates of differences between policy options for many of the detailed financing costs required for this modeling. Given this, and the effect of decreasing overall SREC incentive levels relative to total project cash flow discussed in Section 6.3 below, the results presented could overstate the differences between total incentive required across policy types.

Similarly, the authors found no empirical data in the literature to indicate the magnitude of soft cost savings available under each policy approach. The qualitative and directions impacts are logical, but ultimately the authors used best judgment in developing specific assumptions to illustrate the potential differences, but the figures used could be either

too high or too low. This is an area of potential future study particularly as soft costs become an increasingly large percentage of PV system costs as panel prices continue to decline.

Finally, there is substantial diversity among costs of financing capital and capital structure available to different market participants. The costs and structures used herein are intended to be representative and illustrative; however, the financing costs for individual developers and investors are likely to vary. The results found in this analysis are an effort to best approximate an average PV system in the Massachusetts market and many developers using different financing structures may have different required incentive levels.

6.3 Diminishing Financing Advantages Associated with SREC Revenue Uncertainty as Importance of SREC Revenues Decreases

Revenue sources for solar PV systems consist of SREC payments, Class I REC revenue, federal tax incentives, in addition to the applicable combination of wholesale electricity sales revenue, retail electricity sales revenues under PPAs, avoided retail electricity expenditures, and/or net metering sales. SREC payments are only part of the picture. As the Task 1 analysis has shown, forecasts of declining PV costs and increasing net metering credit values lead to a forecasted decline in the required SREC price under the current policy regime. Similarly, these dynamics also result in a decline in the overall percentage of total project revenue coming from SREC sales. In several of the cases evaluated for Task 1, total required revenue from SREC sales are reduced to zero, with cash flows from non-SREC revenue streams sufficient to meet investor return requirements. The analysis results described in Section 6.1, which assumes static financing cost differentials between different policy regimes, shows some modeled cases in which policies with greater SREC certainty require no SREC revenue to meet investor returns while the same systems installed under a policy with greater SREC uncertainty still require some non-zero SREC price. This result is logically inconsistent. If a system can be installed without the benefit of SREC revenues, then the financiers of that system should be indifferent to the perceived risks between varying SREC policies as no SREC revenue is needed to finance the system. This inconsistency is most pronounced for the residential host-ownership cases reviewed above. Effectively, the approach described in Section 5.2, which uses static financing cost differentials between policies, breaks down as required SREC revenues begin to approach zero.

As noted in this section, PV system owners and other financiers will evaluate and price the risks associated with a particular policy regime leading to differences in financing costs, required SREC incentives and overall policy costs to ratepayers. Under conditions where revenues from SREC sales comprise a substantial proportion of overall system cash flows, differences in policy options will likely lead to more pronounced differences in financing costs (i.e. cost of equity and debt, debt/equity split, debt tenor, etc.) between policy options. On the other hand, under conditions where SREC revenues constitute a relatively small portion of overall system revenues, system owners and other financiers may become indifferent to SREC policy options as the risk associated with any particular policy may have a de minimis effect on the overall risk associated with the project as a whole. As the required revenue from state-based SREC polices approaches zero, project financing costs would increasingly reflect the risks associated with revenues from net metering, federal tax benefits and other cash flows and less the perceived risks associated with any particular SREC policy option. Under these conditions, the financing costs associated with all policies will likely converge, with all policy options commanding similar capital costs.

Table 8 below illustrates the percentage of total revenue derived from SREC payments as modeled in Task 1 under the Base Cost with host ownership and no net metering cap scenario for the WMECO territory.[13] Of note the total required SREC revenue as a percentage of total system revenue in the residential case is significantly below that of the other three system sizes. As shown in the table, SREC revenues make up only 10 percent of all system revenues for residential systems in 2020. Under these conditions, with SREC revenues only a small fraction of total system cash flow, residential PV system financiers may be indifferent to the cash flow from SRECs and would be unlikely to command differential financing costs based on differences in SREC policy types.

Conversely, in cases such as the large rooftop and ground mounted systems, where SREC revenues are a substantial portion of overall system revenue over the life of the analysis, financiers are likely to price the risks associated with different SREC policy structures into the cost of financing.

Table 8. SREC revenue as a percentage of total system revenue for the WMECO host-ownership base cost case.

		2013	2014	2015	2016	2017	2018	2019	2020
Roof	< 15	42%	34%	28%	21%	27%	21%	15%	7%
Roof/Ground	15 - 500	65%	65%	62%	60%	66%	64%	61%	58%
Ground	500+	57%	57%	54%	51%	58%	55%	51%	47%
Landfill	500+	61%	61%	58%	55%	62%	59%	56%	52%

Figure 5 illustrates how this example affects the comparative policy analysis modeling performed as part of this task. As the figure illustrates, modeling of static differential financing costs between different SREC policy options leads to inconsistent results in the residential case where required SREC revenues are a small portion of total system revenues. As the residential graph shows, SREC revenues are required under the soft-floor policy case but not under other policy scenarios, a fundamentally illogical result. As the other graphs in the figure show, when SREC revenues are a substantial proportion of total system revenues, static differences in modeled financing costs lead to SREC revenue requirements that make sense across all policy cases.

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[13] Note that this calculation has been simplified for this example: it does not *explicitly* include system revenues from federal tax benefits (the denominator - levelized revenue requirement - is determined post-tax). Inclusion of such benefits explicitly in the calculation would have the effect of reducing the percentage of total system revenue derived from SREC.

Figure 5. Comparison of Analysis Results for WMECO for Each Market Segment under Different Policy Options
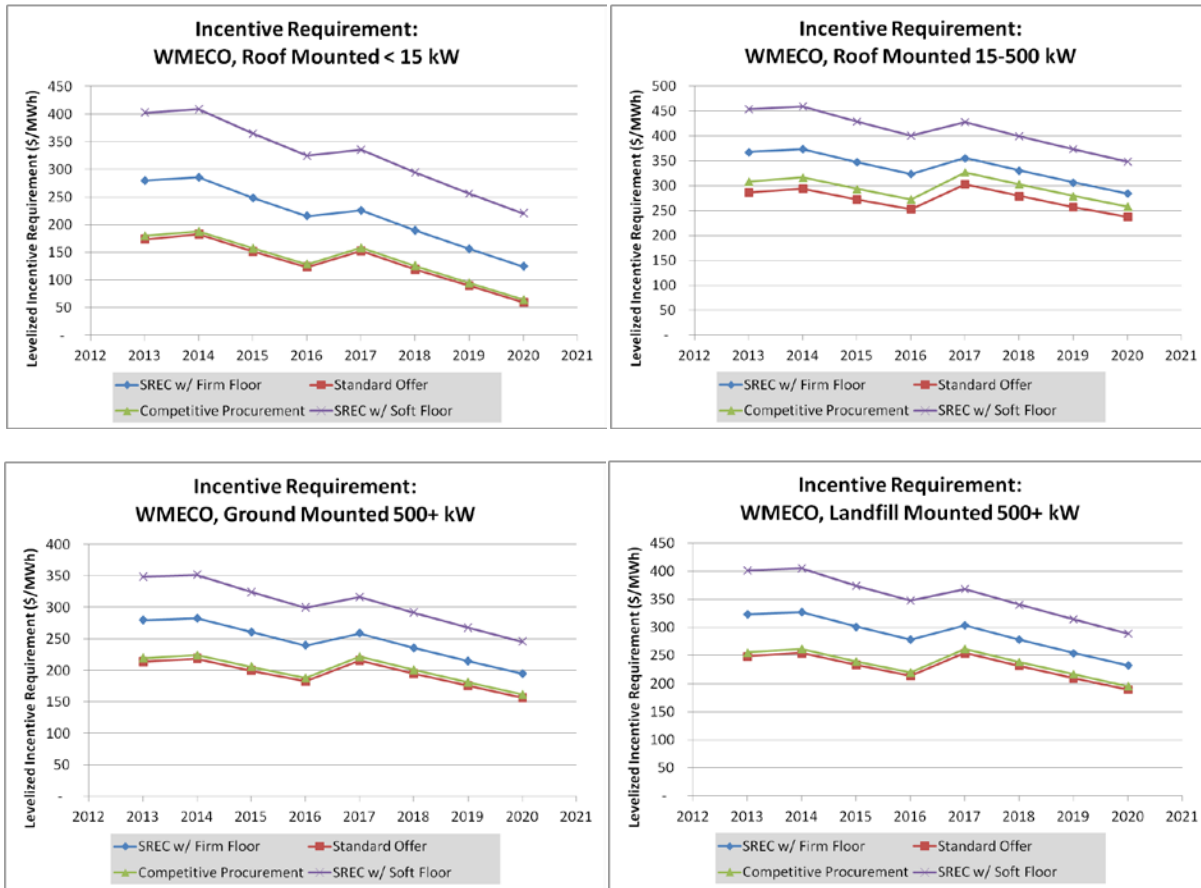
From this perspective, it would be appropriate to modify the analysis assumptions described in Section 5.2 to account for the diminishing financing cost advantage of policies with more predictable and reliable SREC revenue streams as the importance of SREC revenues decreases. Doing so would result in many cases in which the policy incentive would shrink but not disappear (or not disappear nearly as quickly), as was the case using static financing cost differentials between each policy.

However, given that the required SREC incentive (beyond mainstream RPS Class I eligibility) is expected to be reduced to zero at different times for different utility territories under different system size classes and ownership structures, modeling the effect of converging capital costs is a dynamic exercise that is beyond the scope of this analysis. Further research on investor attitudes towards declining SREC payments would need to be conducted to determine at what price levels PV system owners become indifferent to perceived incentive policy risks. In-depth research on this topic may be of interest to state policy makers as the Massachusetts solar market matures in the coming years.

6.4 Derivation of SREC Factor

Additional insight on the potential impact of alternative policy approaches on incentive parameters can be demonstrated through use of equations modeling the relationship between the 10-year levelized incentive necessary to achieve an assumed target rate of return ("10YRLRR"), and the parameters of a SREC policy. As discussed in the Task 1 report, since policy structure and policy objectives influence incentive design, the incentive-setting process is not based solely on an estimate of the 10YRLRR. Rather, DOER would set the incentive parameters: if an SREC market structure,

DOER would establish the ACP and price floor, as well as the SREC Factor for each installation type. If a SREC standard offer, DOER would establish the SREC payment level. Establishing these incentive parameters requires that DOER make:

- Decisions, i.e. how aggressive or conservative the incentive should be relative to the range of 10-year incentive requirements calculated for each market segment based on potential future cost trajectories, ownership options and financing costs); and
- Assumptions regarding how market participants view the policy landscape - including the degree to which investors discount the SREC price floor (during times of surplus) and the ACP (during times of shortage), the proportion of the 10-year SREC period influenced by shortage or surplus, the time value of money, and the Class I REC revenue after the 10 year SREC period - in making their financial projections.

As introduced in the Task 1 Report, converting the projections of 10YRLRR to DOER's selected SREC Factor can be accomplished via the following transformative steps:

1. Select the applicable 10YRLRR results for a specific installation type of interest, or convert the 10YRLRR results to a desired 10-year levelized incentive based on the aggressive-conservative decision and other policy choices, such as the degree of differentiation between installation types.[14]
2. Establish a declining schedule of ACP and Auction Floor prices, and convert those schedules to a constant equivalent levelized schedule for each using an appropriate nominal discount rate.
3. Make assumptions for the following parameters and market expectations to solve for an installation-type specific average expected revenue per SREC generated, as follows:

Expected Avg. Revenue/SREC = **Equivalent Constant Auction Price * $(1-d_f)$ * Y_A + Equivalent Constant ACP Rate * $(1-d_{ACP})$ * Y_{ACP}**

where:

Equivalent Constant Auction Price =	Levelized value of declining Auction Floor Price schedule based on assumed discount rate ($/SREC)
Equivalent Constant ACP Price =	Levelized value of declining Alternative Compliance Payment schedule based on assumed discount rate ($/SREC)
d_{ACP} =	Assumed market discount to ACP in shortage years (%)
Y_{ACP} =	Assumed market percent of 10 SREC period years (randomly distributed) with market expected to be short (relying on ACPs)
d_f =	Assumed market discount to soft floor (%)
Y_A =	Assumed market percent of 10 SREC period years (randomly distributed) with adequate supply (with SREC sellers relying on auction revenue)

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[14] As an example, if DOER does not wish to differentiate incentives between utility territories or ownership types, it would select a position within the range of these results.

4. Determine the SREC Factor needed to provide the desired 10YRLRR for the selected installation type (from step 1) by dividing by the value for Expected Avg. Revenue/MWh (from step 3) , as follows:

SREC Factor (SREC/MWh) =   10YRLRR ($/MWh) / Expected Avg. Revenue per SREC ($/SREC) Here, we illustrate the impact of policy design on incentive using these equations and assumptions for a sample installation size/type/ownership case, a large (500 kW+) ground-mounted PV installation owned by 3rd-party investors interconnected in the Mass Electric (National Grid) territory, with no net metering cap, for year 2015. The SREC Factor , the number of SRECs conveyed to a system owner per MWh produced for the first 10 years of production, is calculated under each policy.

SREC Factor with Soft Floor

For this example, we assume the following:

d_f =   10% (consistent with ~ 2 year payment lag when the market relies on the auction, a compound time value of money to the investor)

d_{ACP} =   5%

Y_A =   70% (i.e. 7 out of 10 years relying on the auction)

Y_{ACP} =   30% (i.e. 3 out of 10 years with market expected to be short

For the calculation of the SREC Factor, the following assumptions are made:

Auction floor price schedule =   Starting at $350/MWh in 2014 and declining 6% per year

ACP schedule =   Starting at $465/MWh in 2014 and declining 6% per year

Discount rate for calculating constant equivalent values for Auction/ACP Schedules = 10%

The 10YRLRR result for the SREC policy with soft floor for the Base Cost case is $260.50/MWh. We assume for this illustration that the incentive level is set to be in the middle of the range (the installed cost mean), neither aggressive nor conservative, and matching the needs of projects located in the specified service territory.

The calculated SREC Factor result for this illustration is as follows:

SREC Factor = 0.974 SRECs/MWh

SREC Factor with Firm Floor

In this case, with the floor firm, if we assume the 10YRLRR is the same ($261/MWh), we would make the following change:

d_f =   0% (consistent with a firm floor that can be monetized in the year of generation)

The results for this illustration are as follows:

SREC Factor = 0.911 SRECs/MWh

As would be expected, firming up the floor allows the SREC Factor to be set at a lower level, allowing for fewer SRECs to be granted per MWh while still meeting investor requirements.

However, as described in Section 4 of this report, with a firm floor, the cost of capital would be expected to be lower, and some categories of soft costs reduced. This translates into a lower 10YRLRR of $192.5/MWh. Plugging this value into the equations yields results of

SREC Factor = 0.673 SRECs/MWh

The same caveats as noted in Section 6 apply: the magnitude of these reductions is based on estimates, although the direction is reliable. Nonetheless, it can be seen that firming the auction floor can product substantial reductions in the incentive required.

Appendix A

Survey Questions

1. What role does your company play in the solar industry? (i.e. developer, investor, etc.)

2. What has been the nature of your participation (level of experience) in the <u>Massachusetts</u> SREC carve-out market to date?

3. What market segment(s) do you focus on?
   a. Residential (please specify 3rd-party ownership, direct ownership, or both)
   b. Medium C&I/roof
   c. utility/ground mounted scale
   d. other

4. Please summarize your company's experience financing solar projects.

5. How do you expect that most of your solar projects in Massachusetts will be financed?
   a. Project financed?
   b. Balance sheet financing?
   c. Other? (describe)

6. If you are involved in other state solar markets (like NJ, or NY), was there a difference in cost of capital or capital structure between those markets and Massachusetts?

7. Let's discuss project capital structure, and the cost of debt and equity. We would like to understand how these assumptions might change based on policy design:

	SREC/no floor	SREC/Floor	Standard Offer	Competitive Procurement
Perm. Financing, Debt: %, Term, Interest rate, Target avg. DSCR, Source				
Perm. Financing, Tax Equity: %, AT Target IRR, & Source				
Perm. Financing, Sponsor/Cash Equity: %, AT Target IRR, & Source				
WACC: *As a fall-back*, ask about differences in WACC, by policy?				
Construction Finance: %, Int. Rate & Source, AT Target IRR, & Source… would there be any distinction expected among policies?				
How would transaction costs differ between policies? What types of (soft) costs - customer acquisition costs, administrative overhead, financing, anything else suggested by interviewee - are incurred, increased, minimized or avoided?				
Which policy option do you favor and why?				

8. **(only ask if interviewee plays in residential sector)**
   a. Consider a residential PV project:
      i. owned by the homeowner and financed through a local community bank, *versus*
      ii. the same project owned, installed and maintained by a 3rd-party with nationally-based investors and with a lease or power purchase agreement with the homeowner.

      How would you expect the target return on equity, cost of debt, d/e ratio, and/or transaction & overhead costs to differ between the two?

   b. *DOER is considering a variation on the SREC market model for the residential sector which would involve forward-minting of SRECs. Would you be willing to respond to a brief online survey which further explains the policy, and solicits your reaction to program parameters and opinion on impact on financing or other cost drivers?*

9. **(only ask if interviewee plays in C&I sector)**
   a. Consider a medium scale (e.g. 500 kW) fully net metered PV project owned by:
      i. a group of small, local investors through a "community solar garden" financial model, *versus*
      ii. the same project owned, installed and maintained by a 3rd-party with nationally based investors.

      How would you expect the target return on equity, cost of debt, d/e ratio, and/or transaction & overhead costs to differ between the two?

   b. What do you think the impact of applicable SEC regulation would have on the community solar garden model? Are you aware of community financing schemes that have managed to satisfy SEC issues in a commercially-viable manner?

10. **(only ask if developer plays in the +500 ground mount sector)**
    a. Does siting projects on landfill sites impact overall system installed costs and if so, by how much on a percentage basis?

11. **Do you have suggestions regarding others to interview?**

Appendix B

Task 2 Results

3rd Party Private Ownership

Figure 6: Incentive Requirement: Mass Electric (National Grid), Roof Mounted < 15 kW Residential
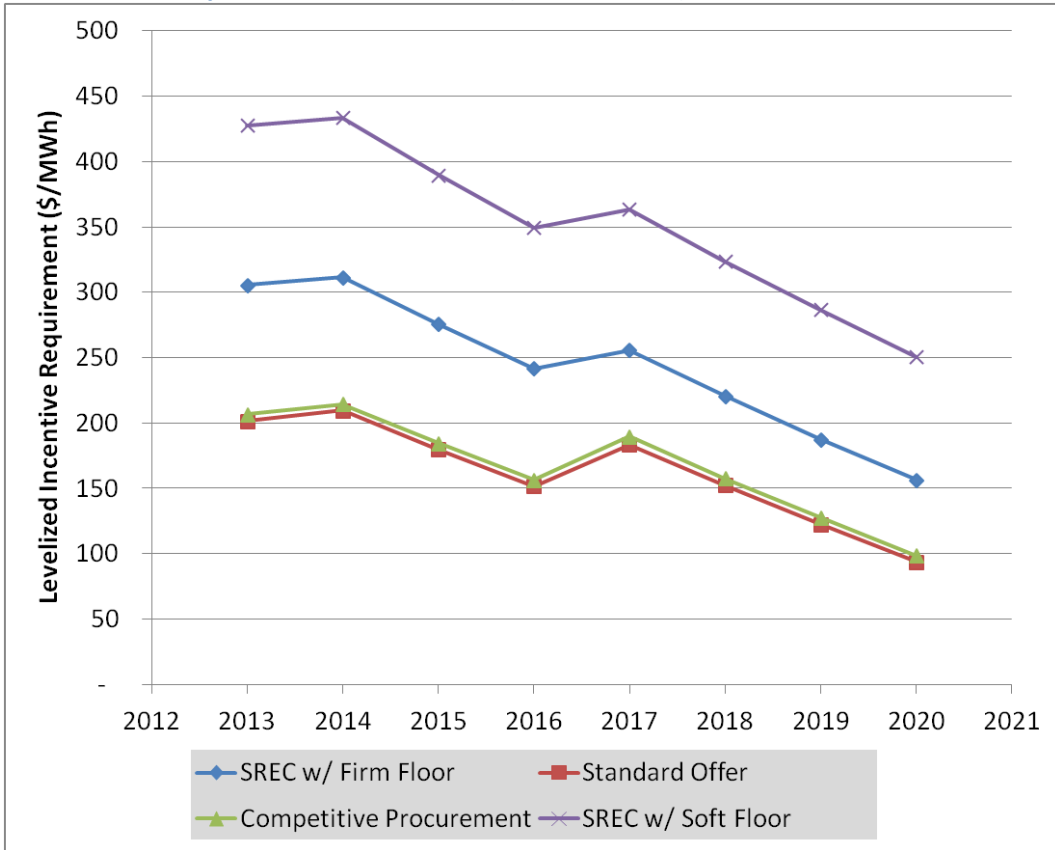
Figure 7: Incentive Requirement: Mass Electric (National Grid), Roof Mounted 15-500 kW

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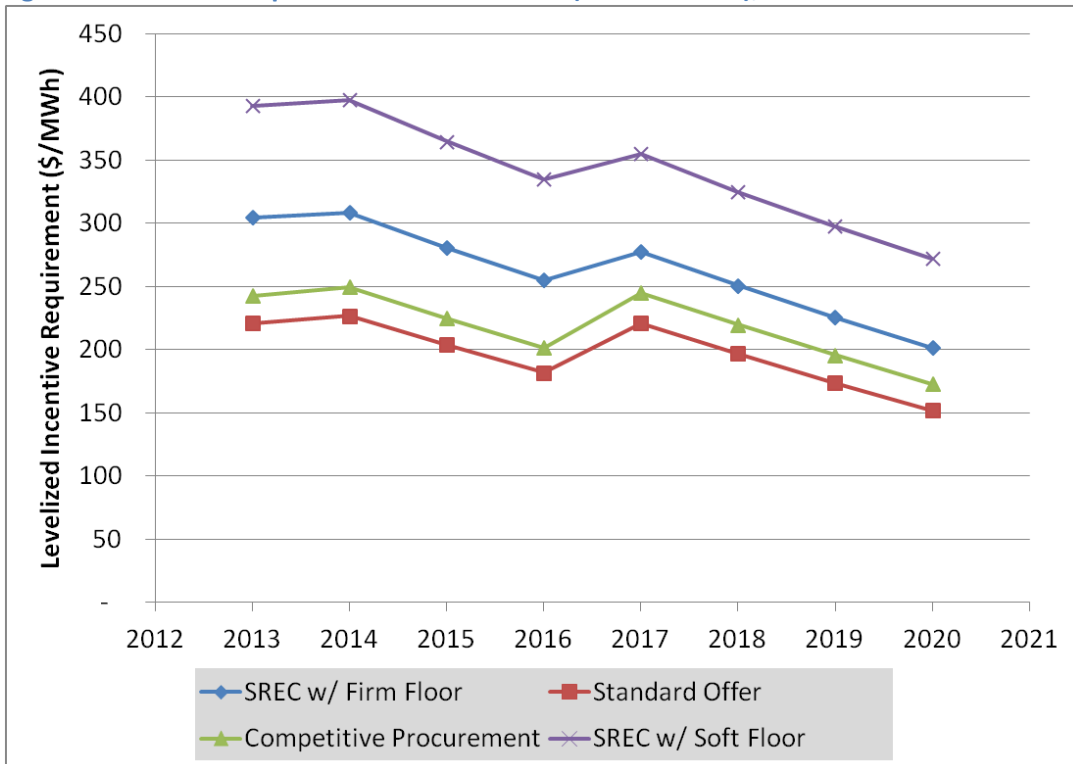
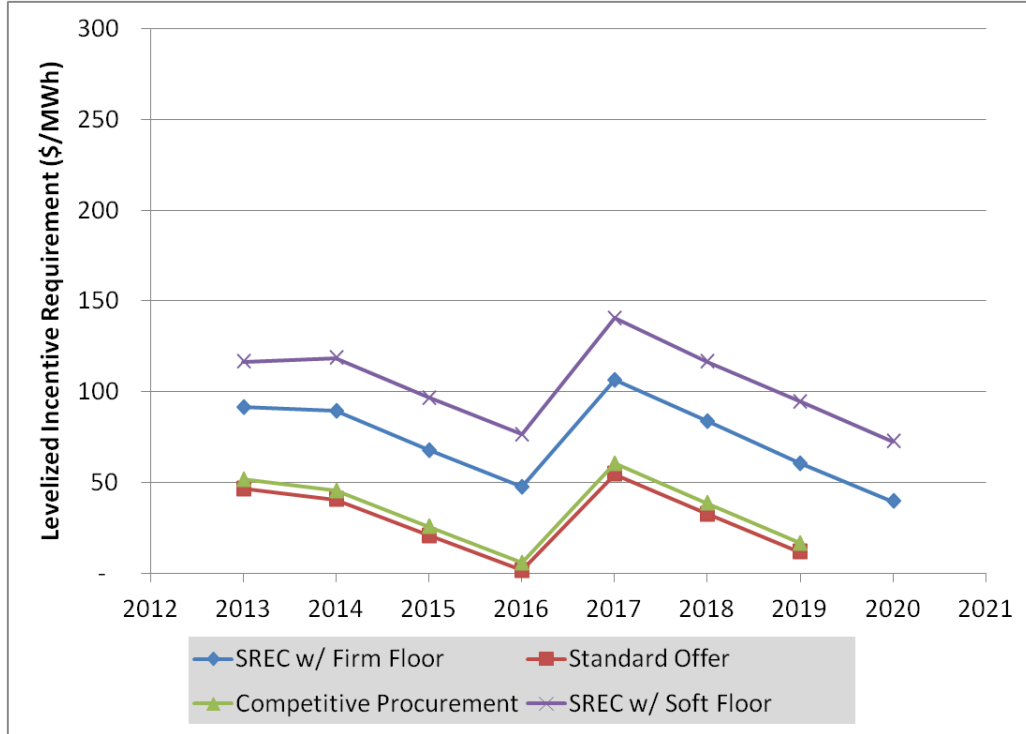**Figure 8: Incentive Requirement: Mass Electric (National Grid), Ground Mounted 500+ kW**
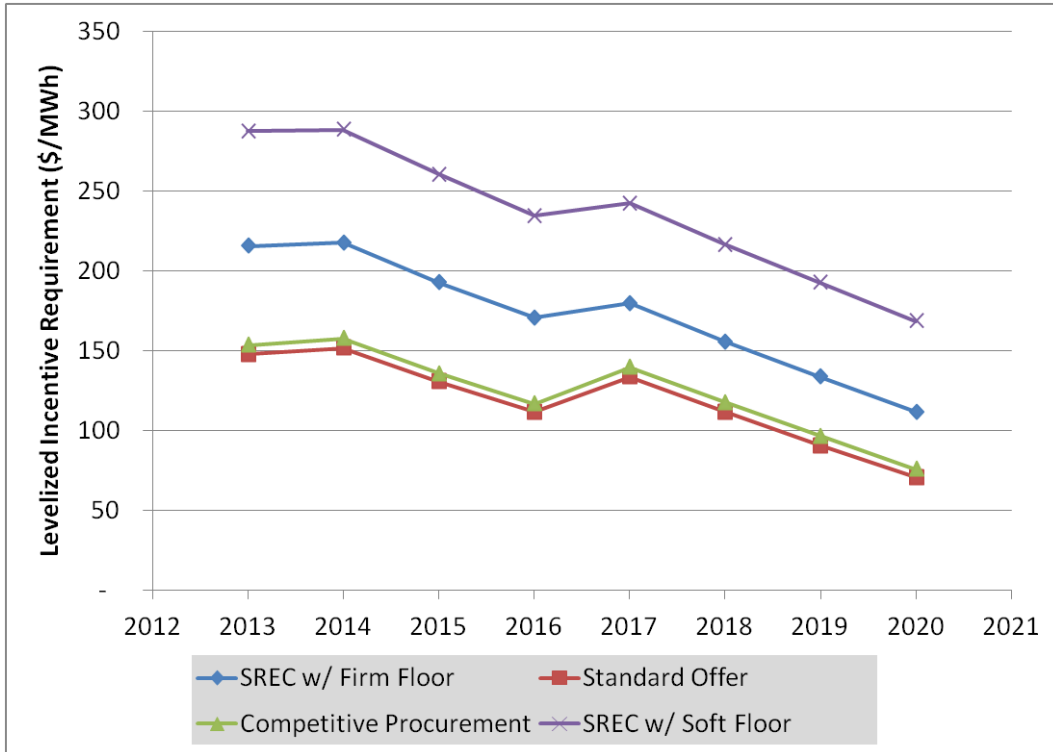
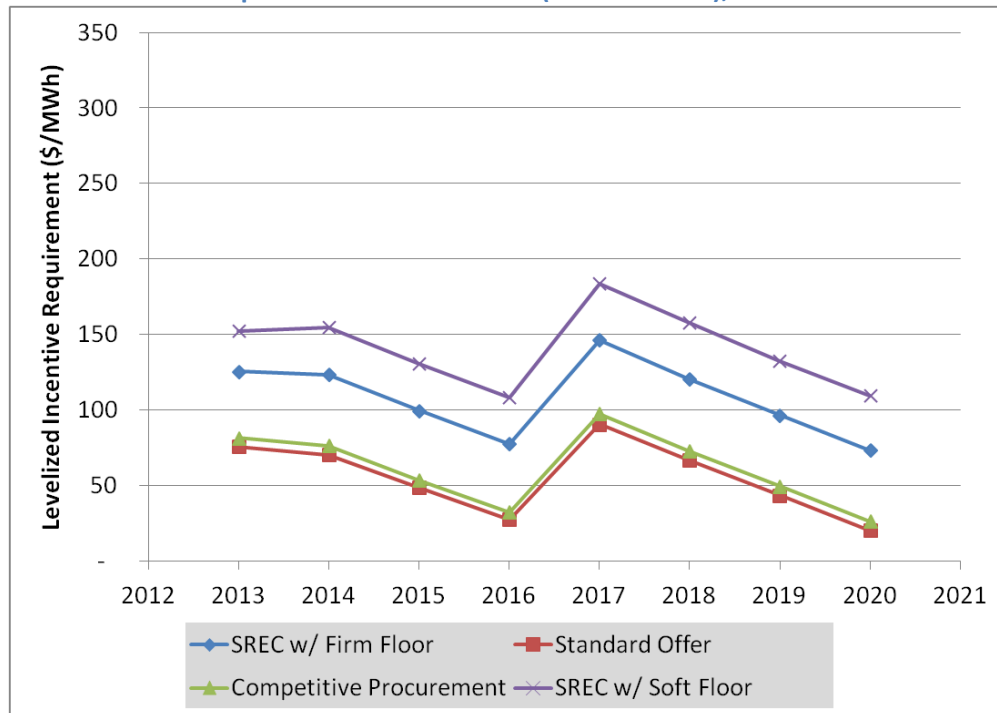**Figure 9: Incentive Requirement: Mass Electric (National Grid), Landfill Mounted 500+ kW**

4
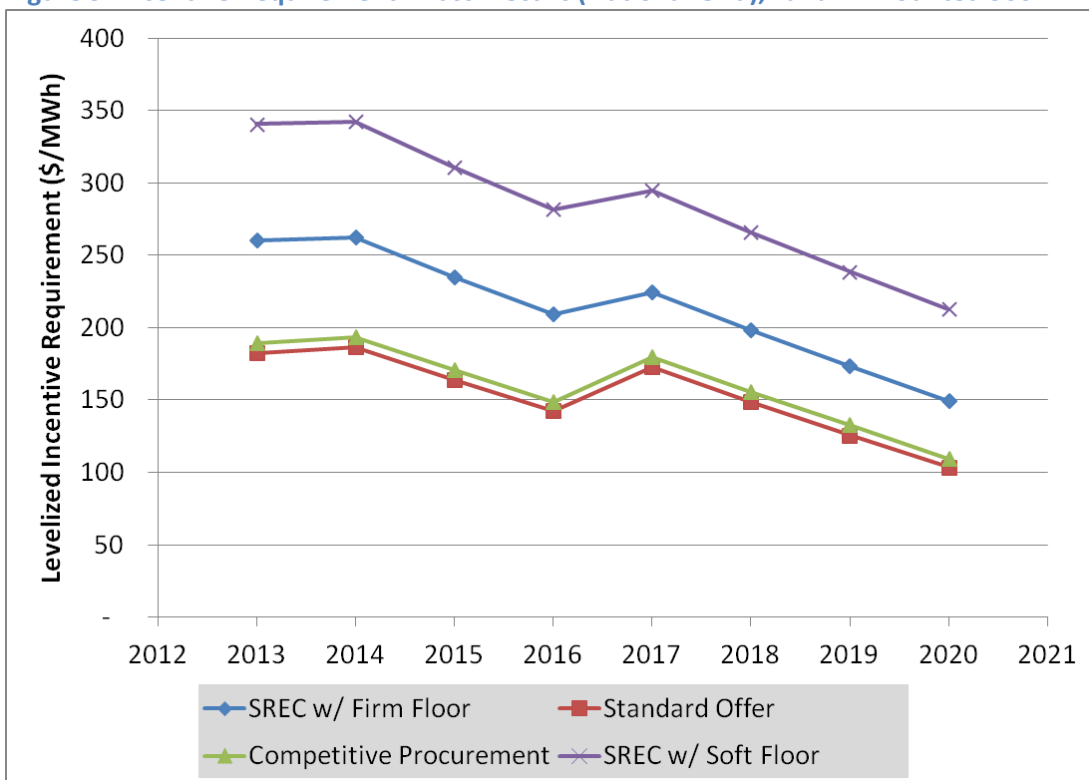
Figure 10: Incentive Requirement: WMECO, Roof Mounted < 15 kW Residential
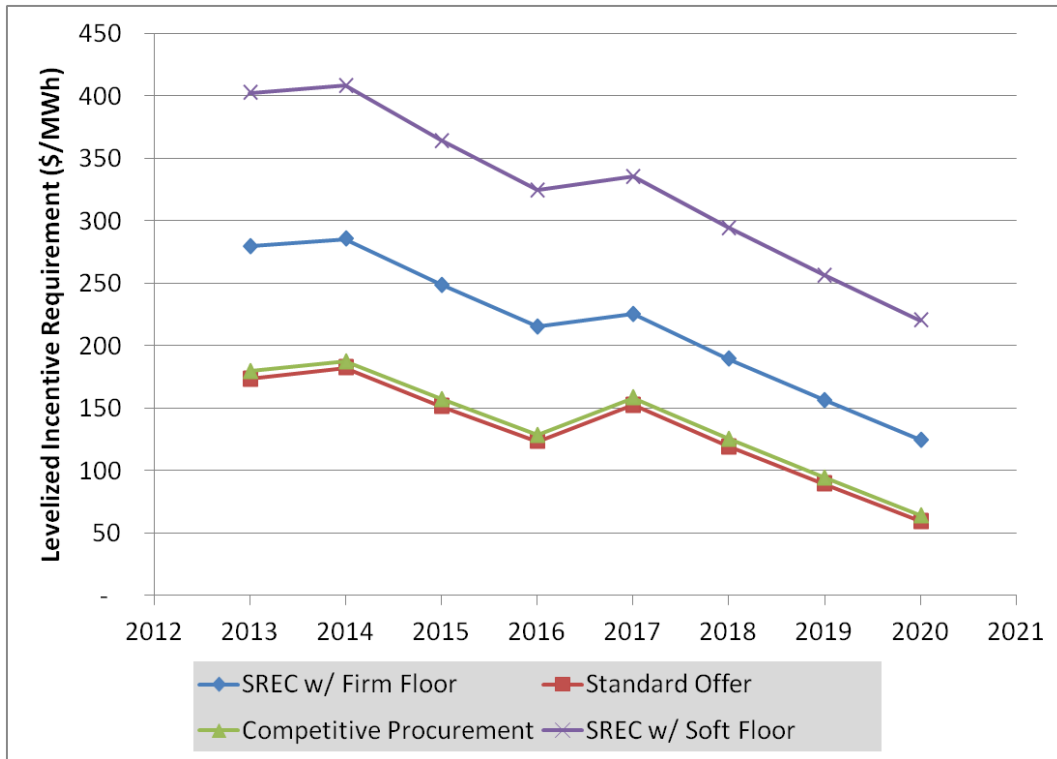
Figure 11: Incentive Requirement: WMECO, Roof Mounted 15-500 kW
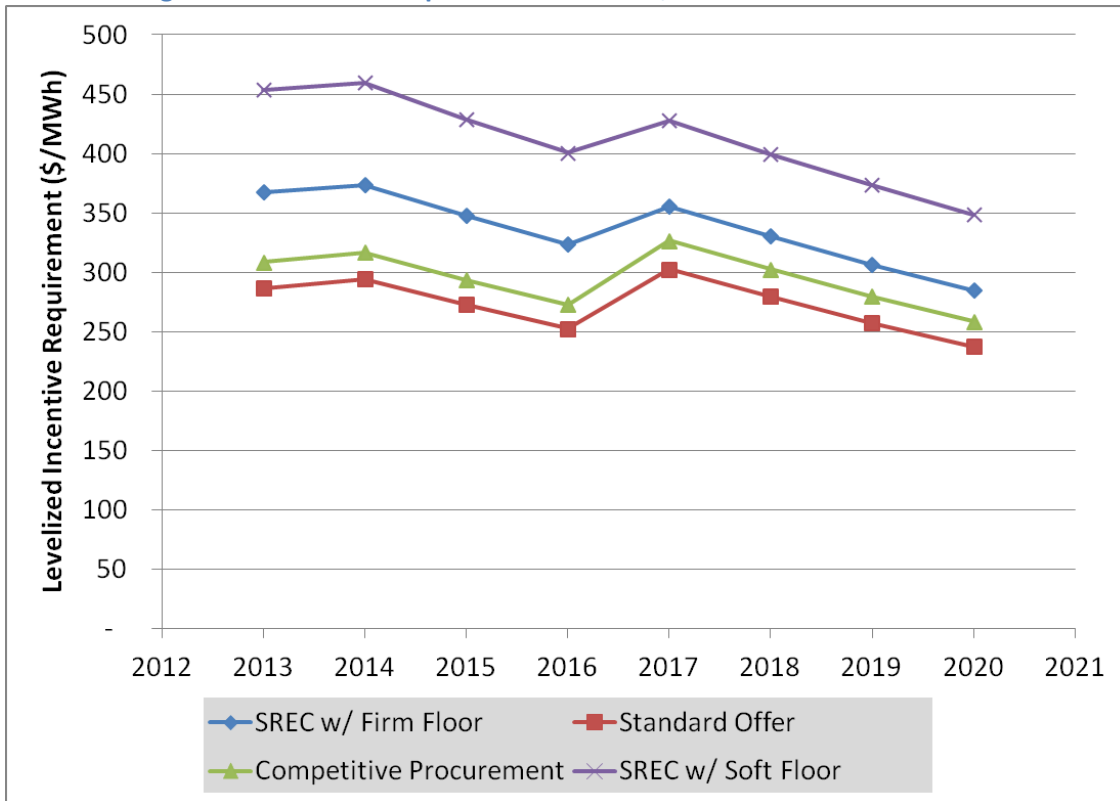
Figure 12: Incentive Requirement: WMECO, Ground Mounted 500+ kW
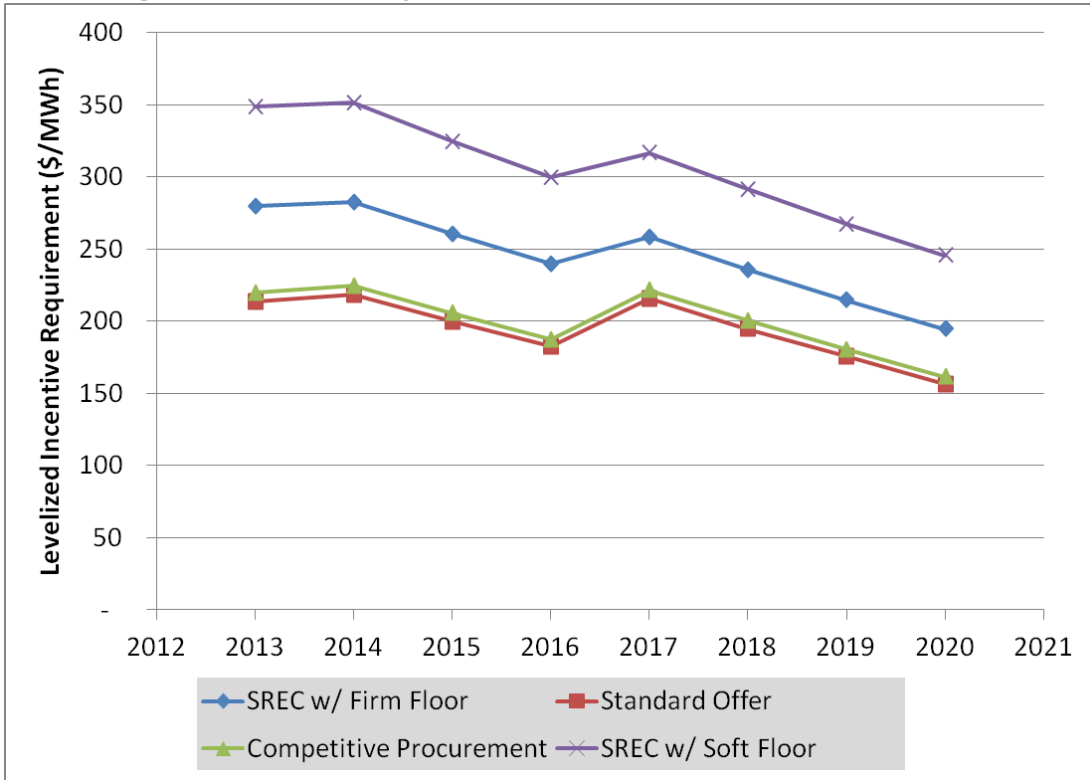
Figure 13: Incentive Requirement: WMECO, Landfill Mounted 500+ kW
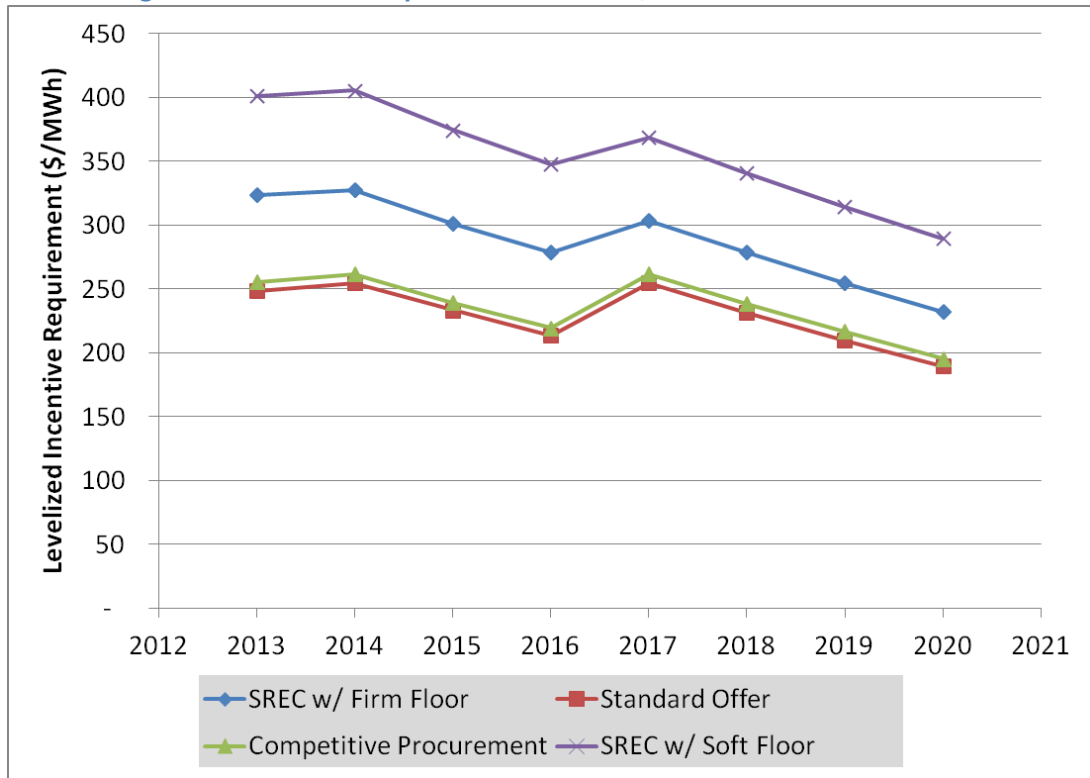
Figure 14: Incentive Requirement: Boston Edison (NSTAR), Roof Mounted < 15 kW Residential
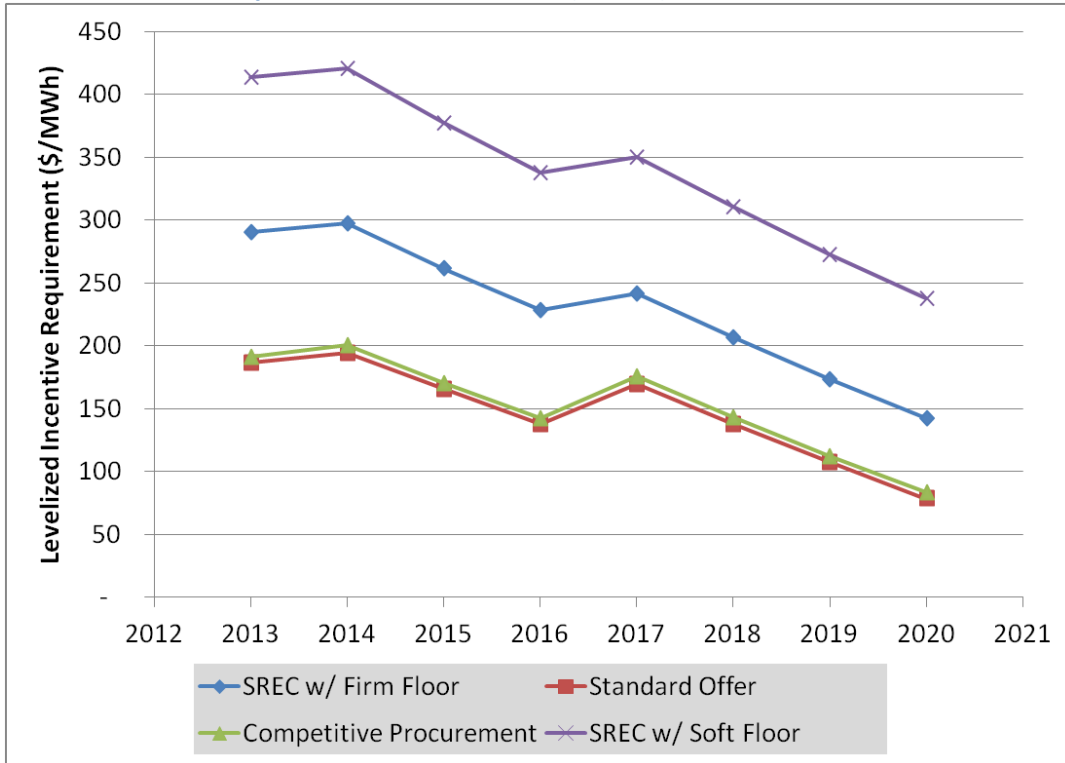
Figure 15: Incentive Requirement: Boston Edison (NSTAR), Roof Mounted 15-500 kW
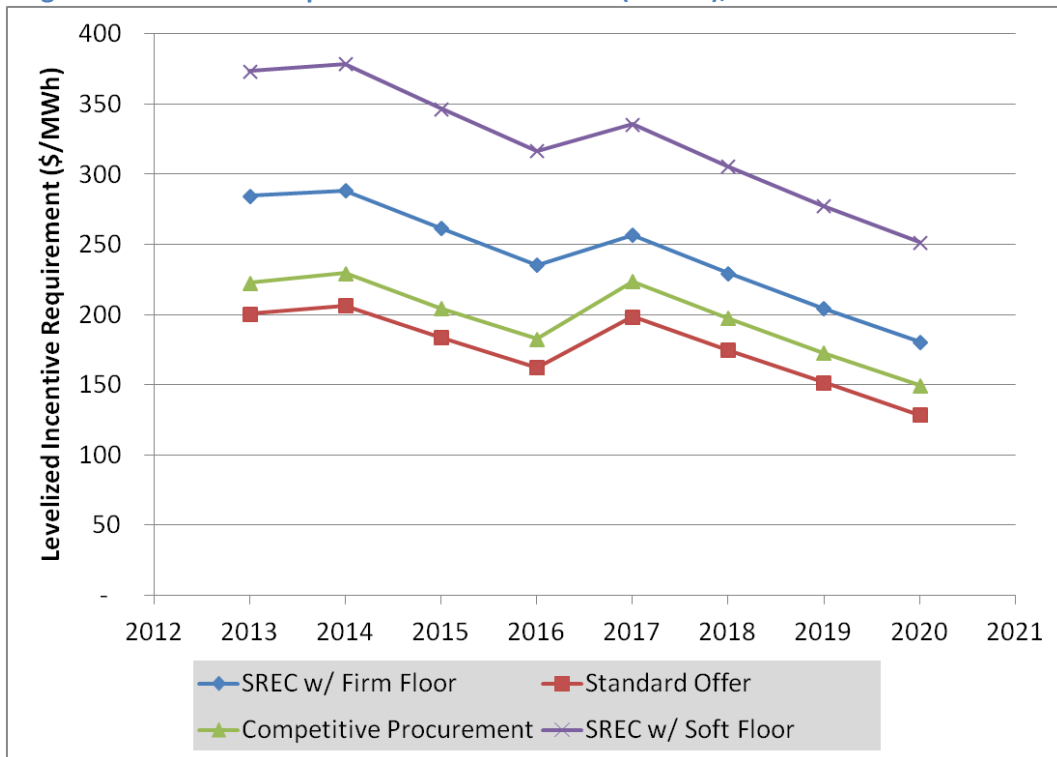
Figure 16: Incentive Requirement: Boston Edison (NSTAR), Ground Mounted 500+ kW
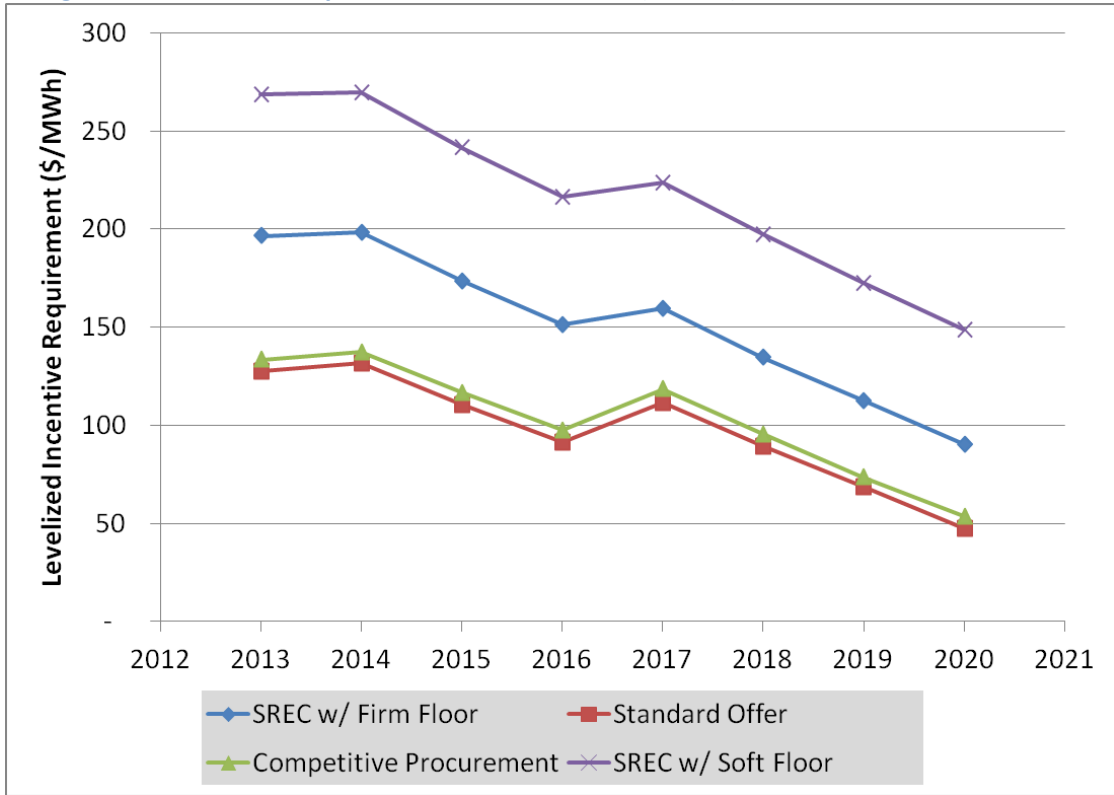
Figure 17: Incentive Requirement: Boston Edison (NSTAR), Landfill Mounted 500+ kW
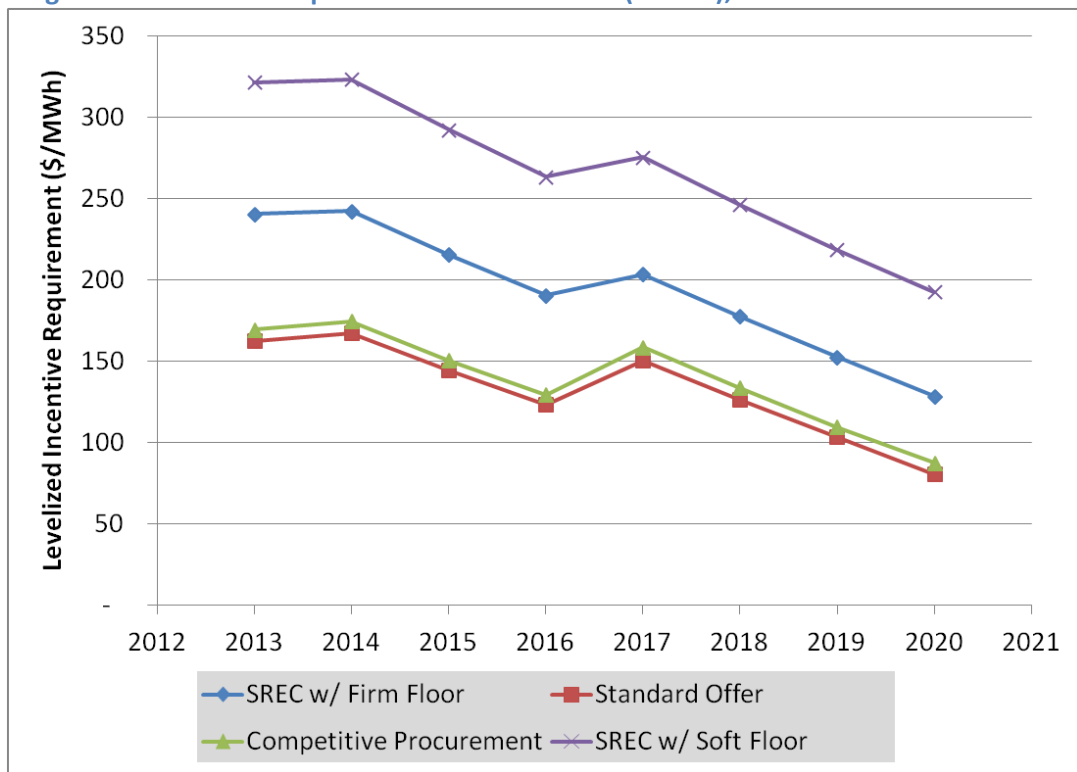
Figure 18: Incentive Requirement: Commonwealth Electric (NSTAR), Roof Mounted < 15 kW Residential
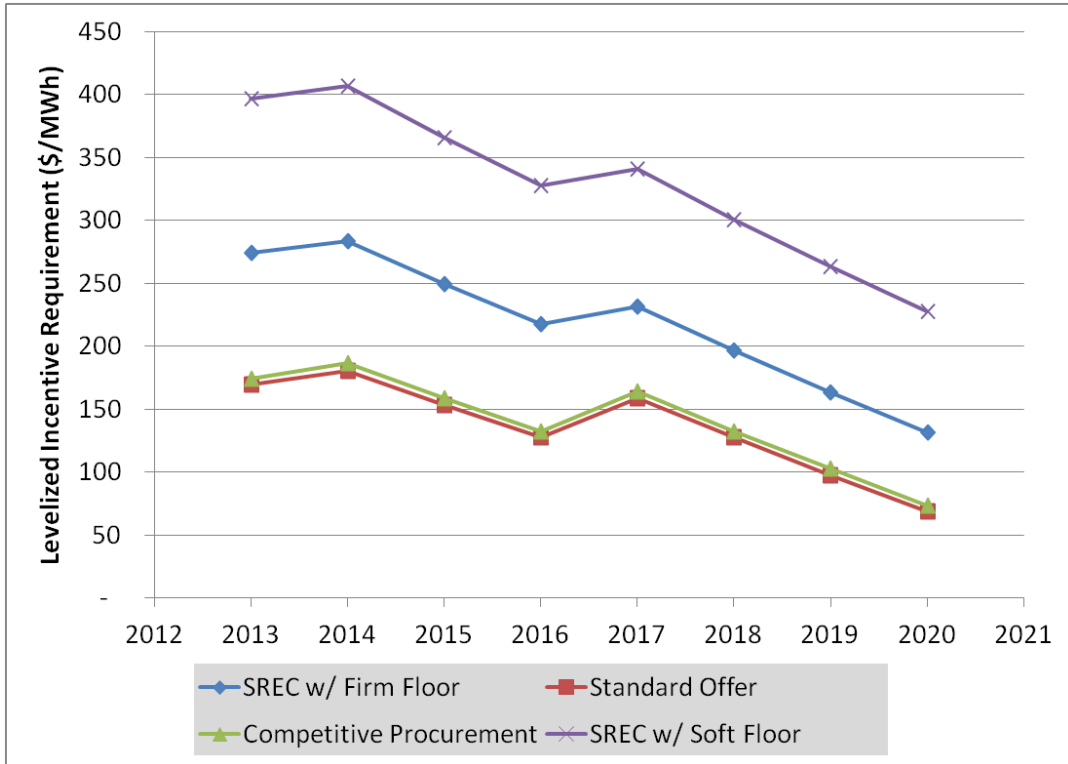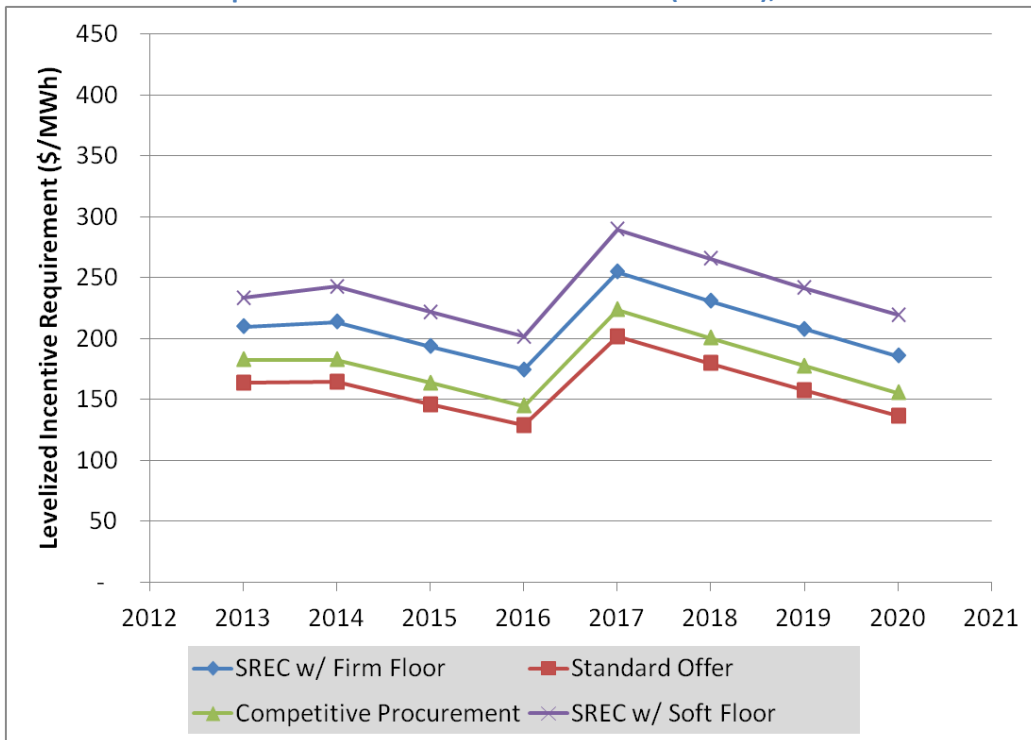
Figure 19: Incentive Requirement: Commonwealth Electric (NSTAR), Roof Mounted 15-500 kW
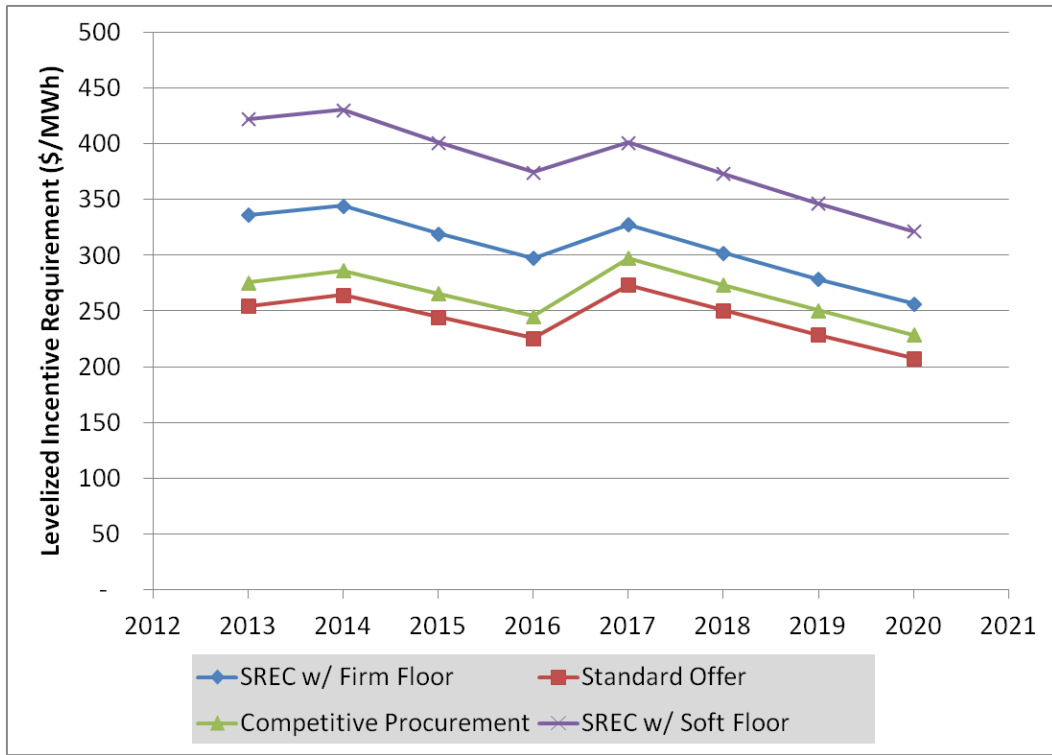
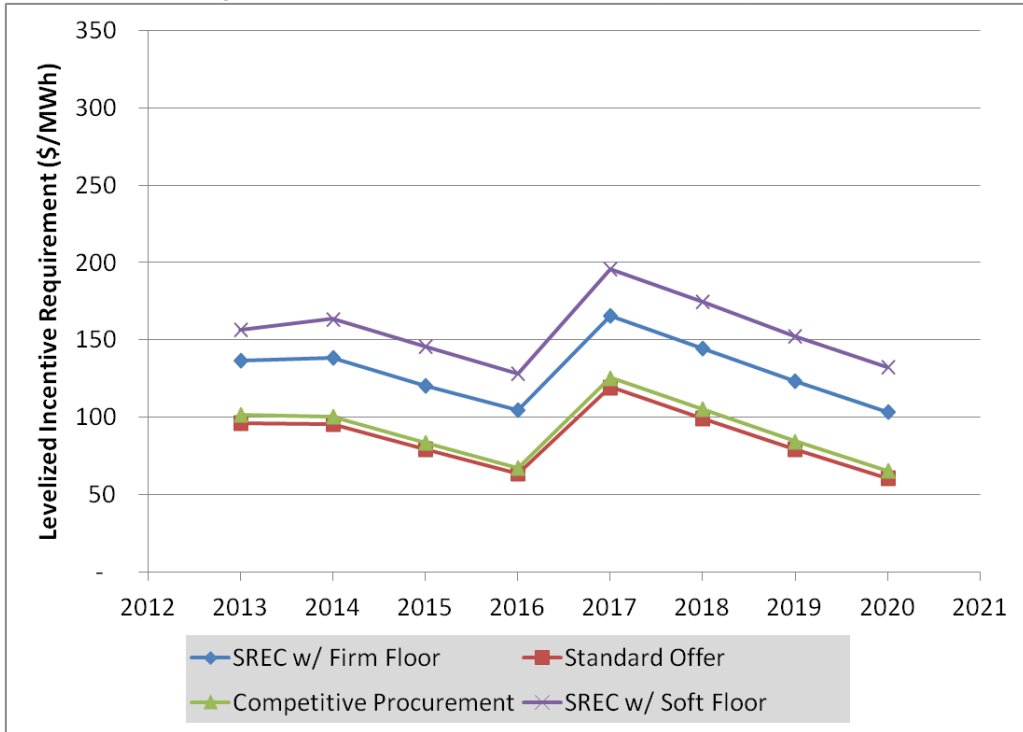**Figure 20: Incentive Requirement: Commonwealth Electric (NSTAR), Ground Mounted 500+ kW**
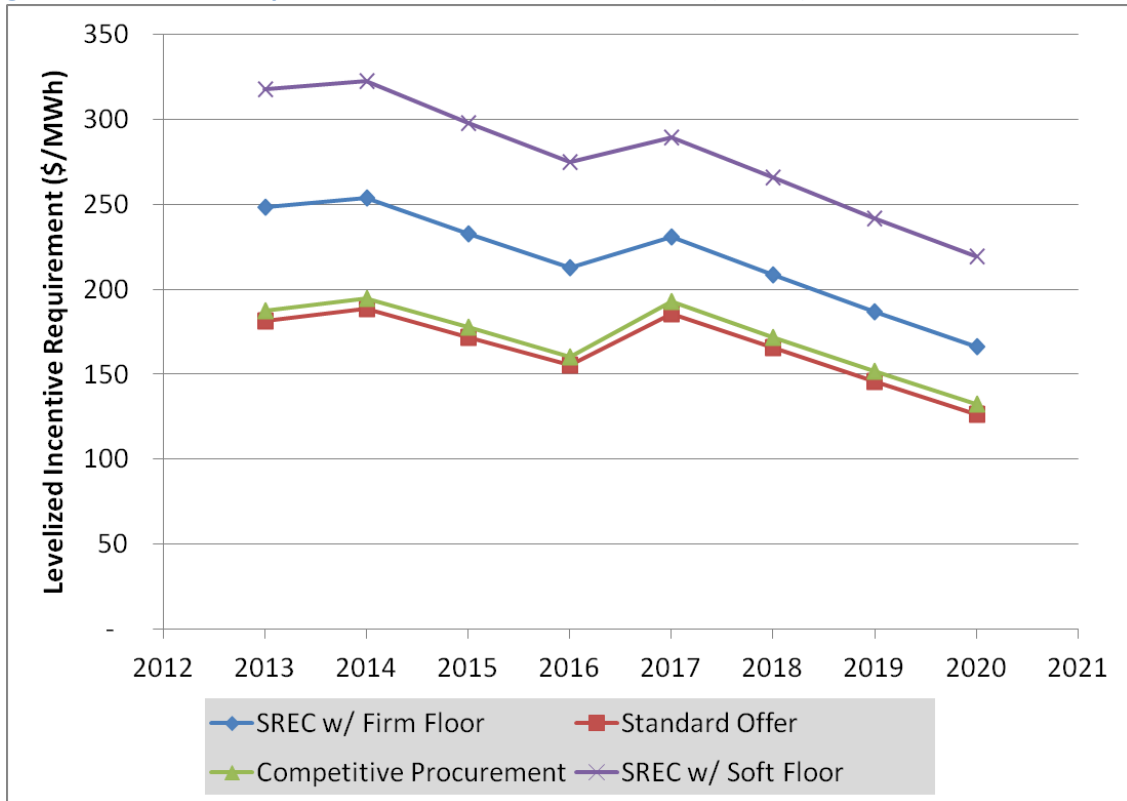
Figure 21: Incentive Requirement: Commonwealth Electric (NSTAR), Landfill Mounted 500+ kW
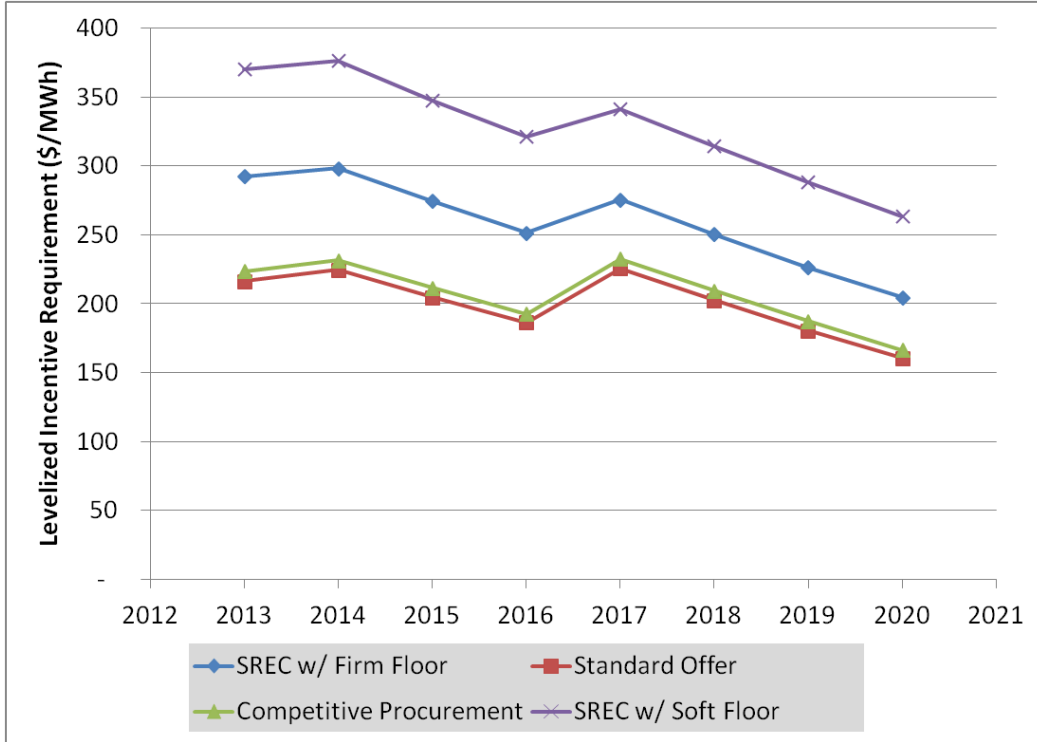
Host Ownership

Figure 22: Incentive Requirement: Mass Electric (National Grid), Roof Mounted < 15 kW Residential
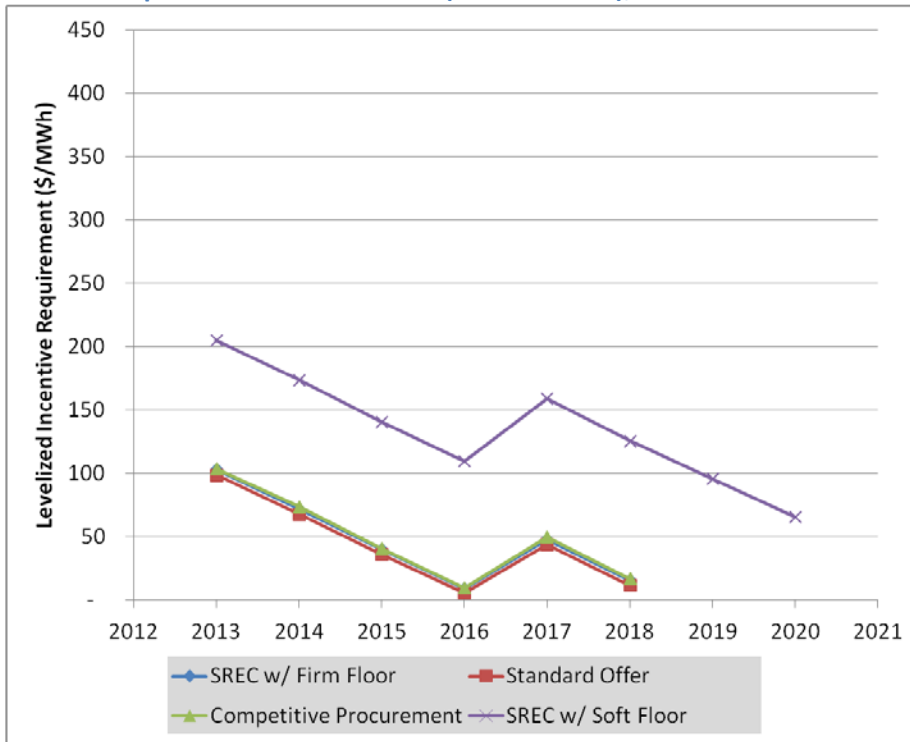
Figure 23: Incentive Requirement: Mass Electric (National Grid), Roof Mounted 15-500 kW
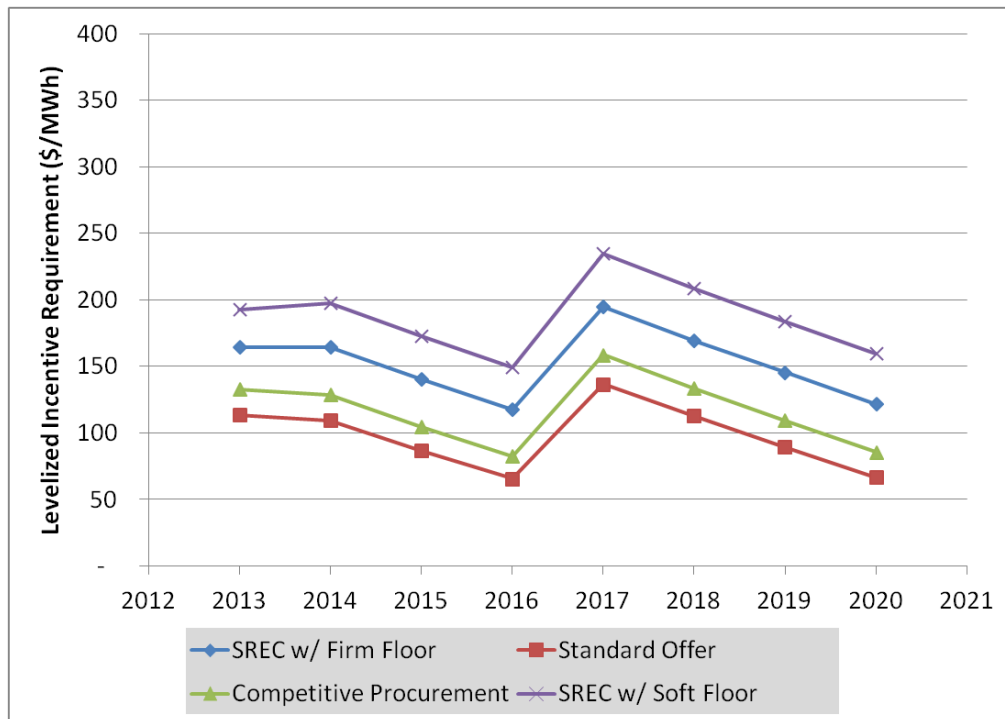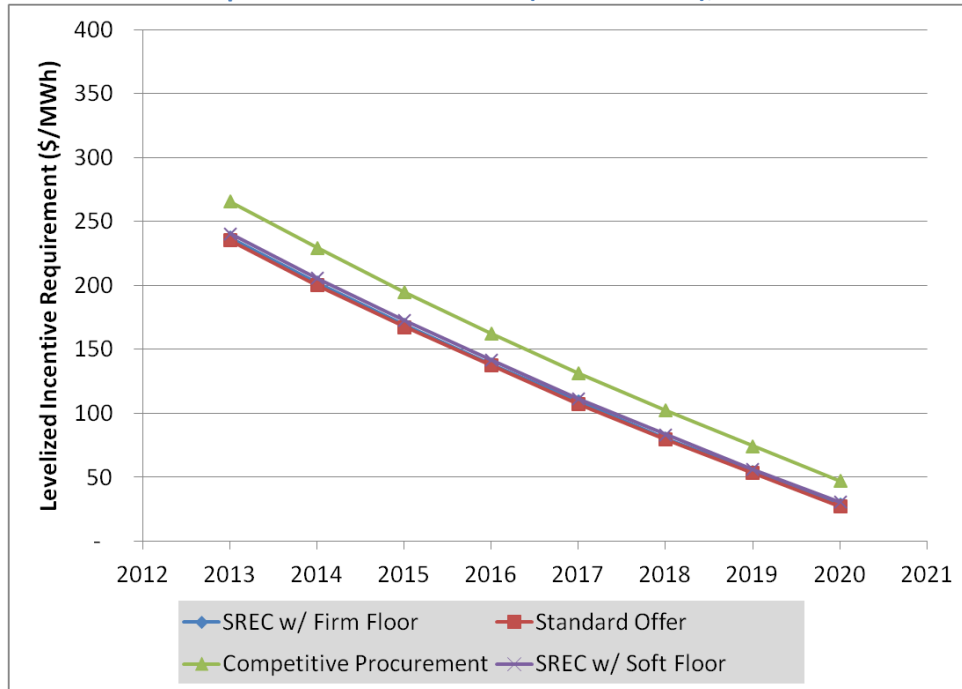
Figure 24: Incentive Requirement: Mass Electric (National Grid), Ground Mounted 500+ kW
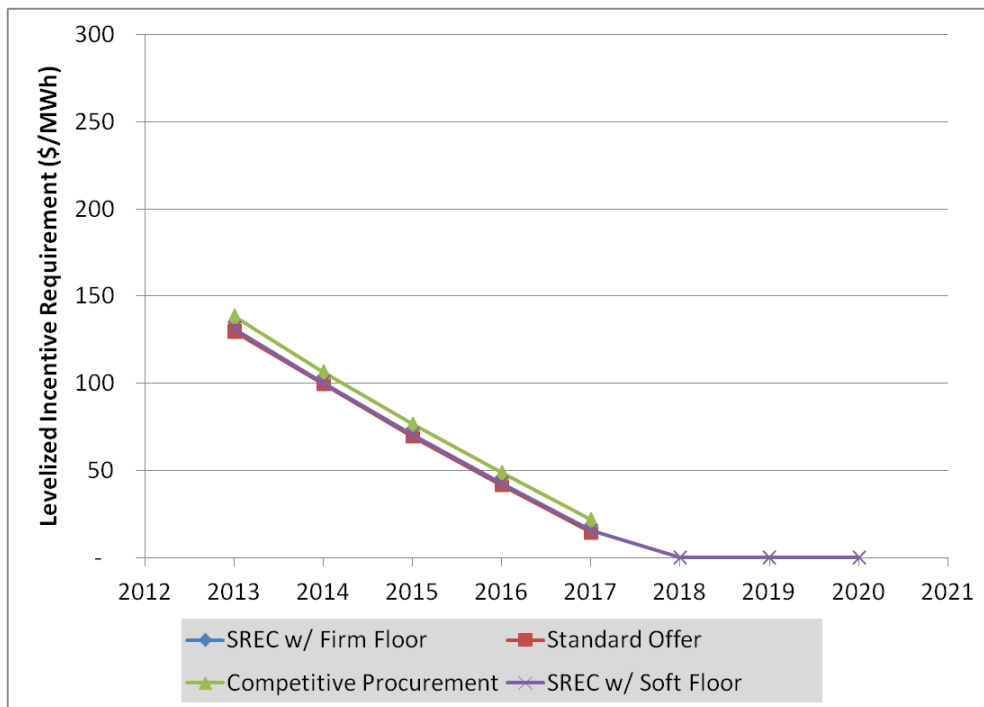

Figure 25: Incentive Requirement: Mass Electric (National Grid), Landfill Mounted 500+ kW
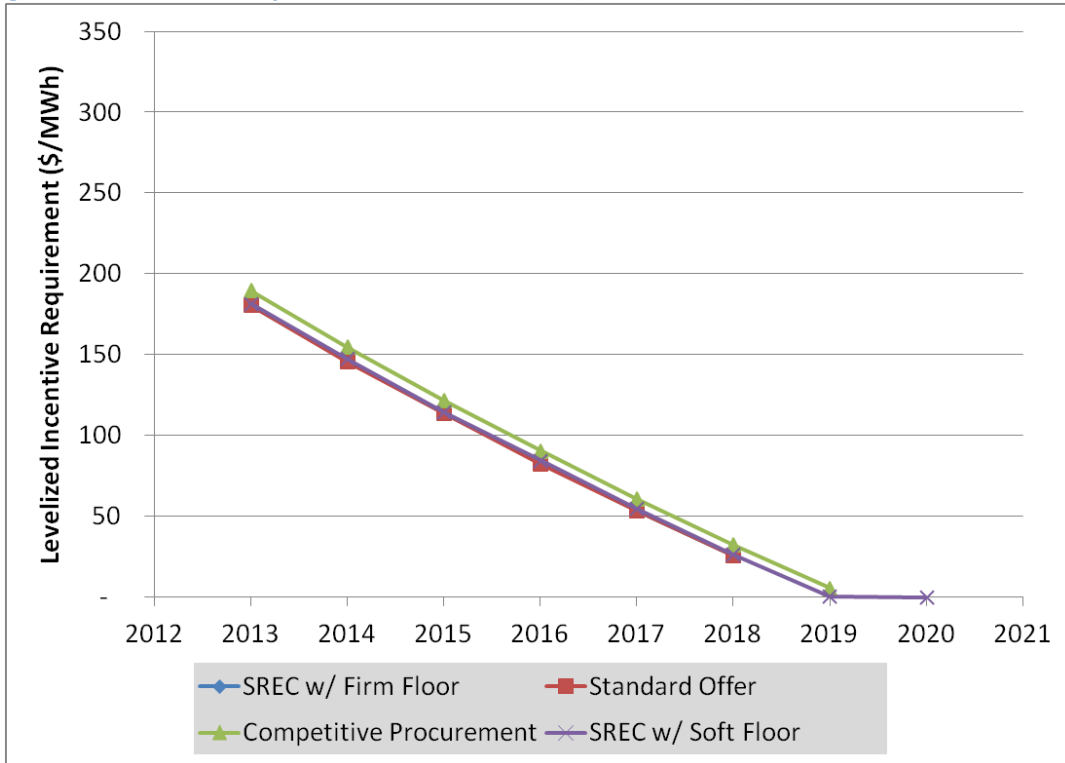
Figure 26: Incentive Requirement: WMECO, Roof Mounted < 15 kW Residential
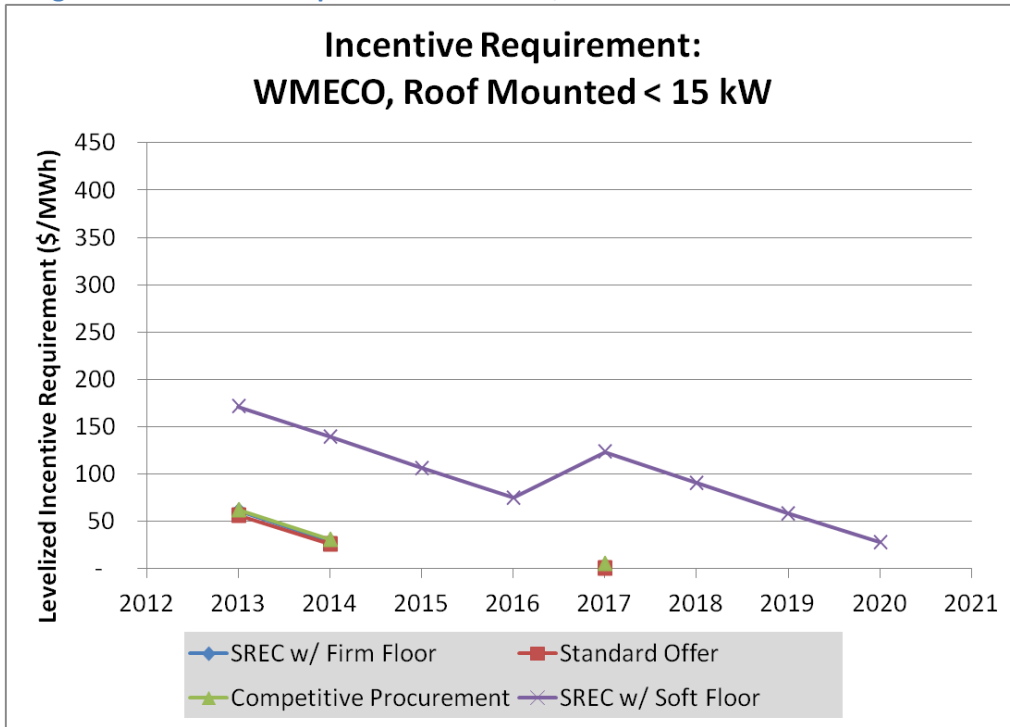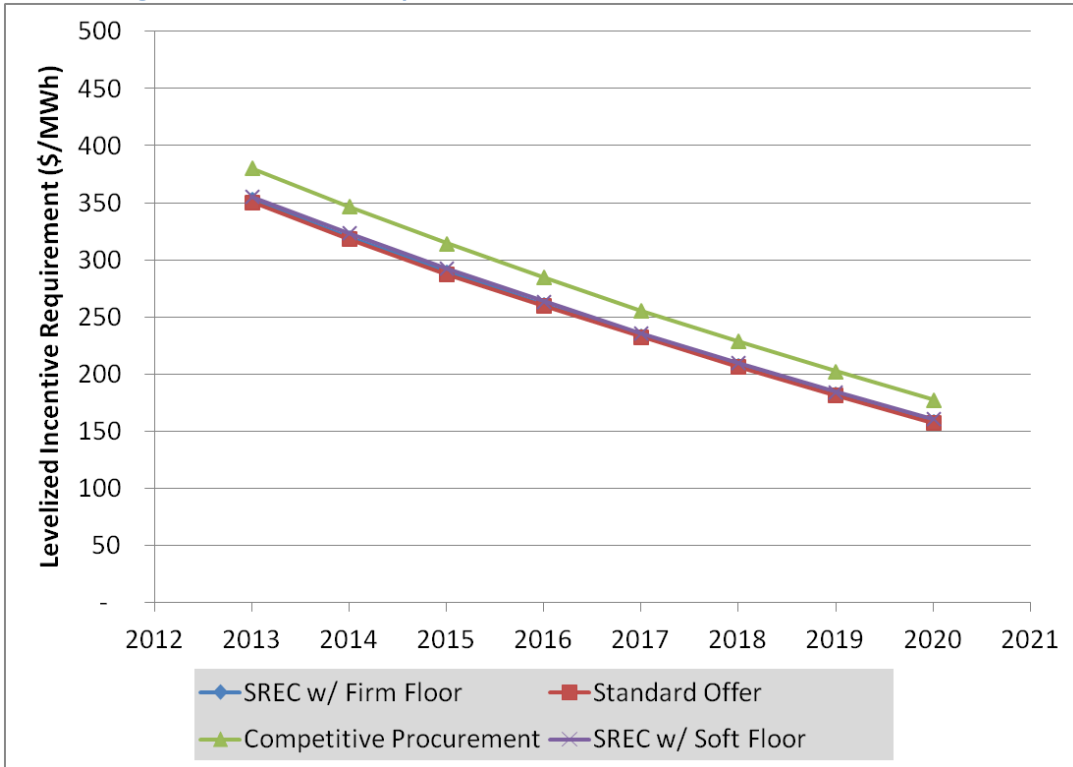

Figure 27: Incentive Requirement: WMECO, Roof Mounted 15-500 kW

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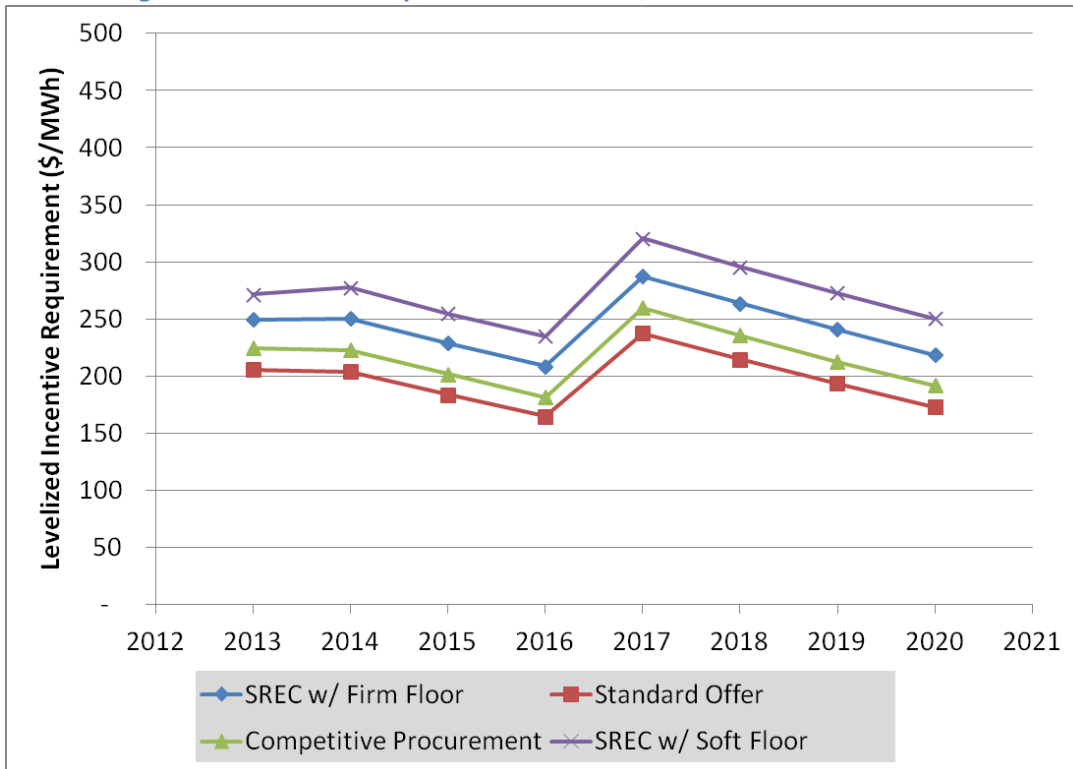
Figure 28: Incentive Requirement: WMECO, Ground Mounted 500+ kW
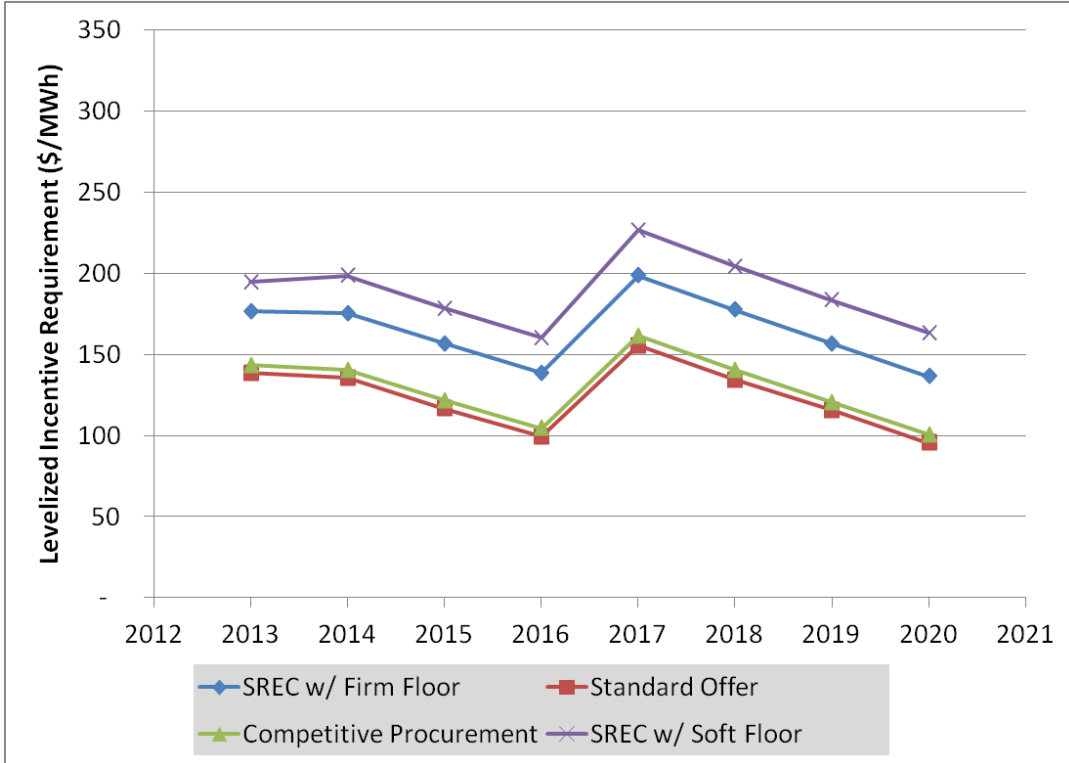
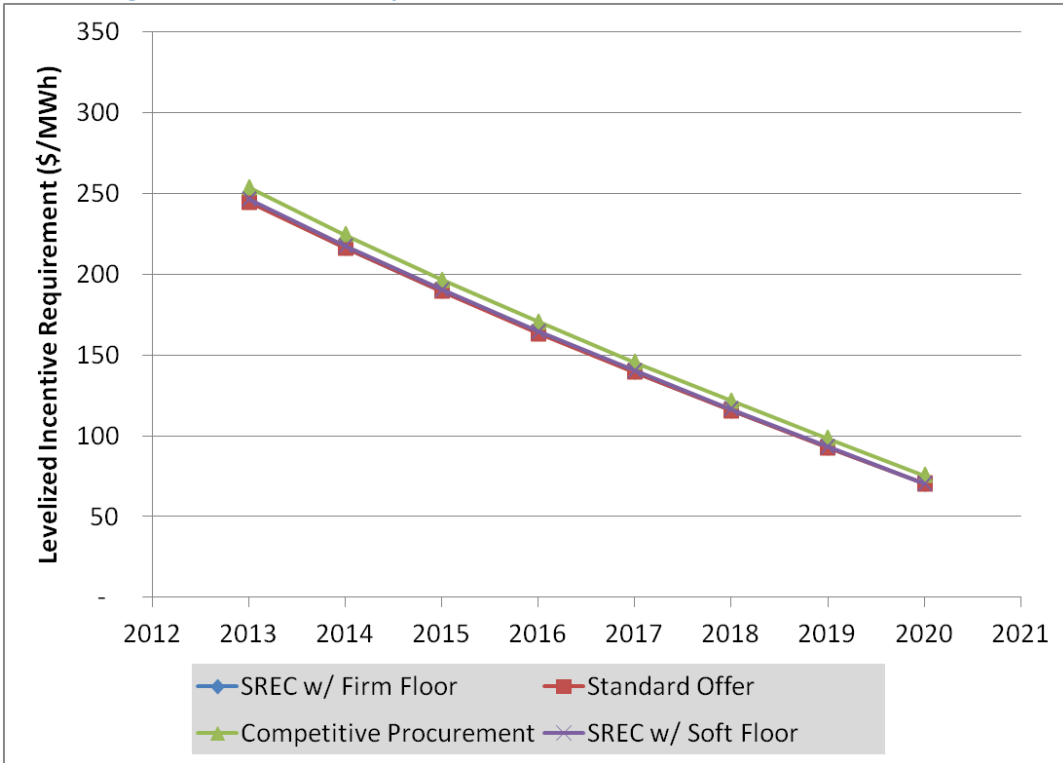**Figure 29: Incentive Requirement: WMECO, Landfill Mounted 500+ kW**
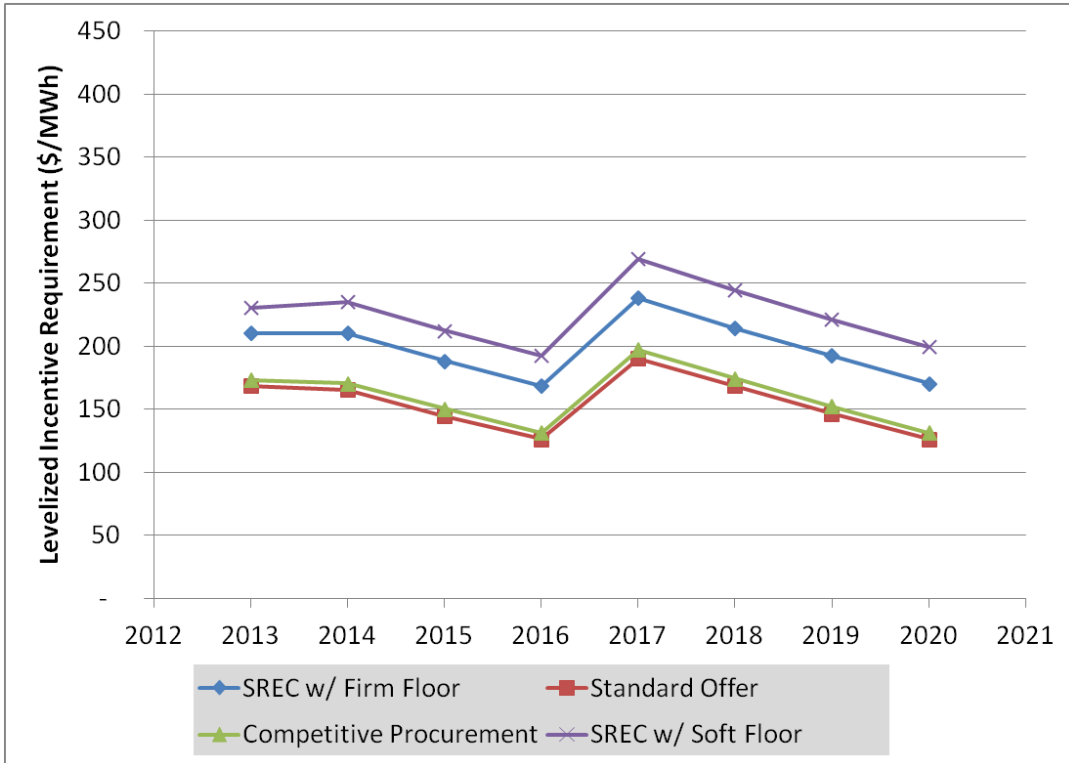
Figure 30: Incentive Requirement: Boston Edison (NSTAR), Roof Mounted < 15 kW Residential

Incentive Requirement:
Boston Edison (Nstar), Roof Mounted < 15 kW

Legend: SREC w/ Firm Floor, Standard Offer, Competitive Procurement, SREC w/ Soft Floor
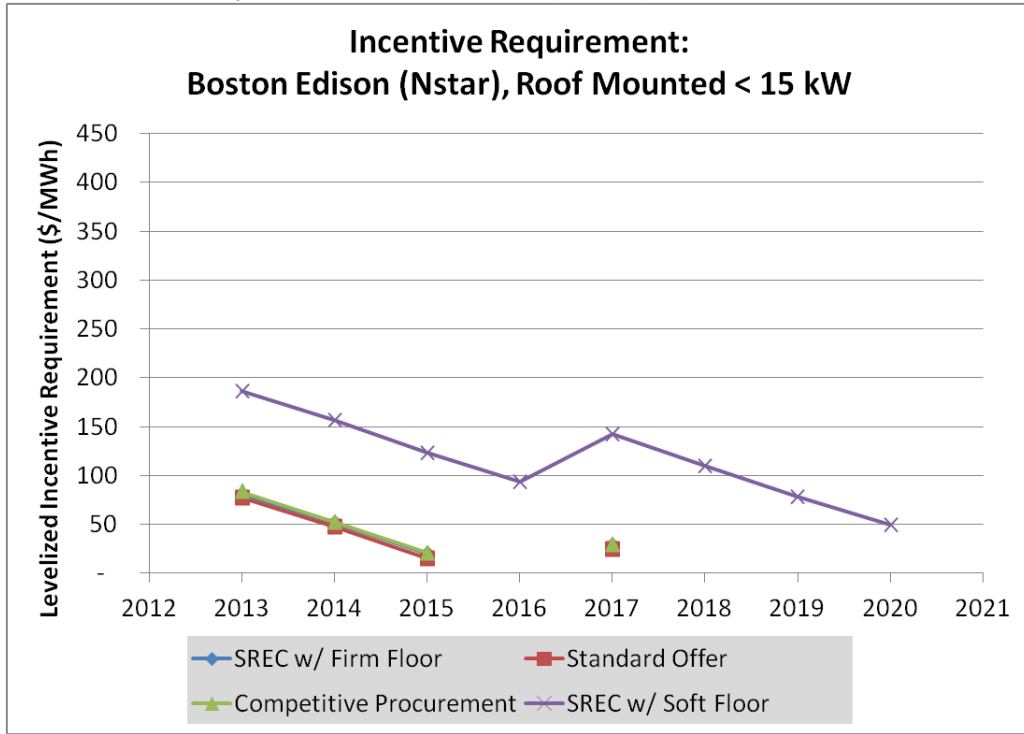
Figure 31: Incentive Requirement: Boston Edison (NSTAR), Roof Mounted 15-500 kW

Legend: SREC w/ Firm Floor, Standard Offer, Competitive Procurement, SREC w/ Soft Floor
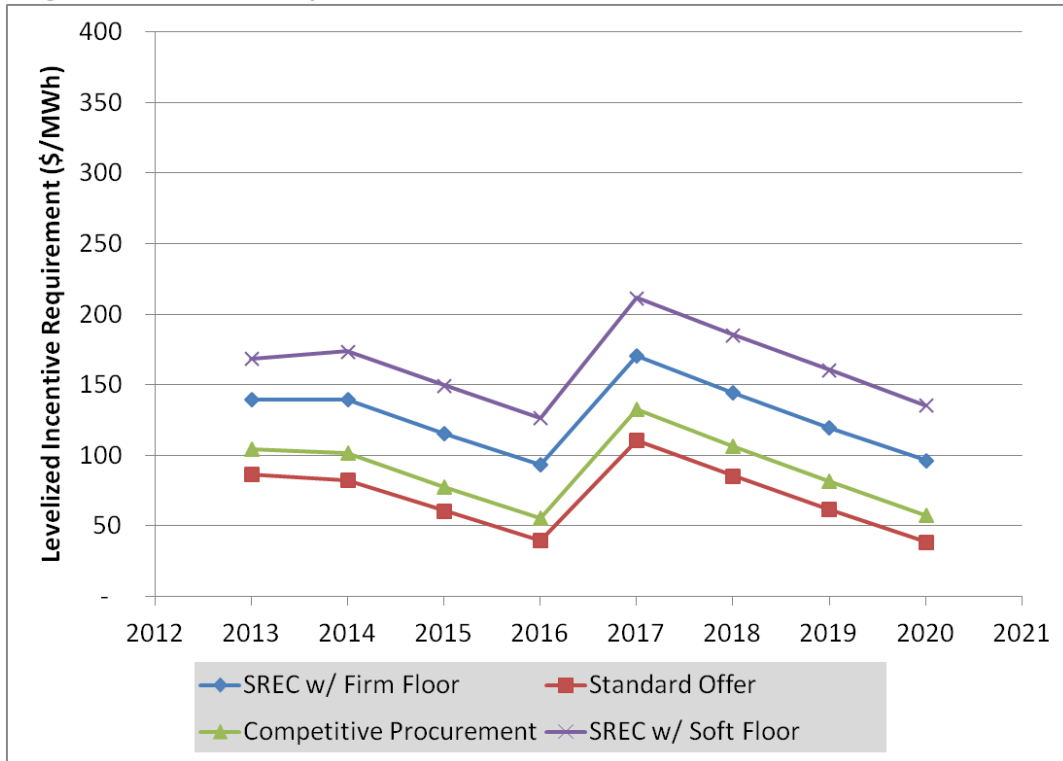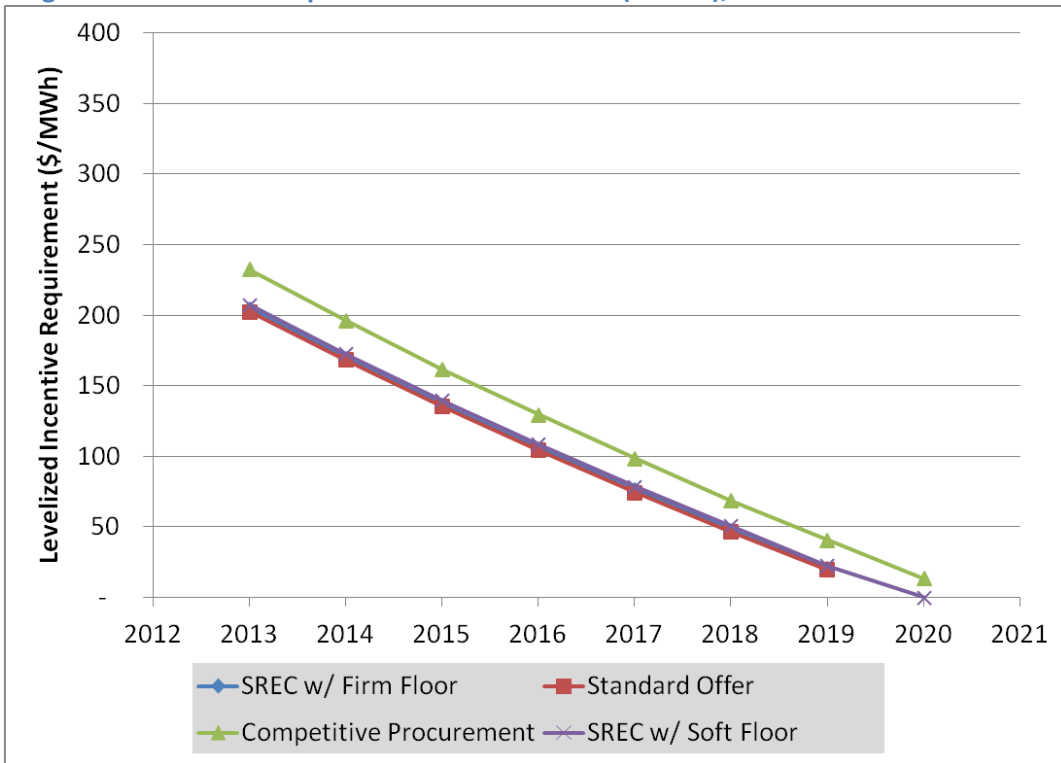
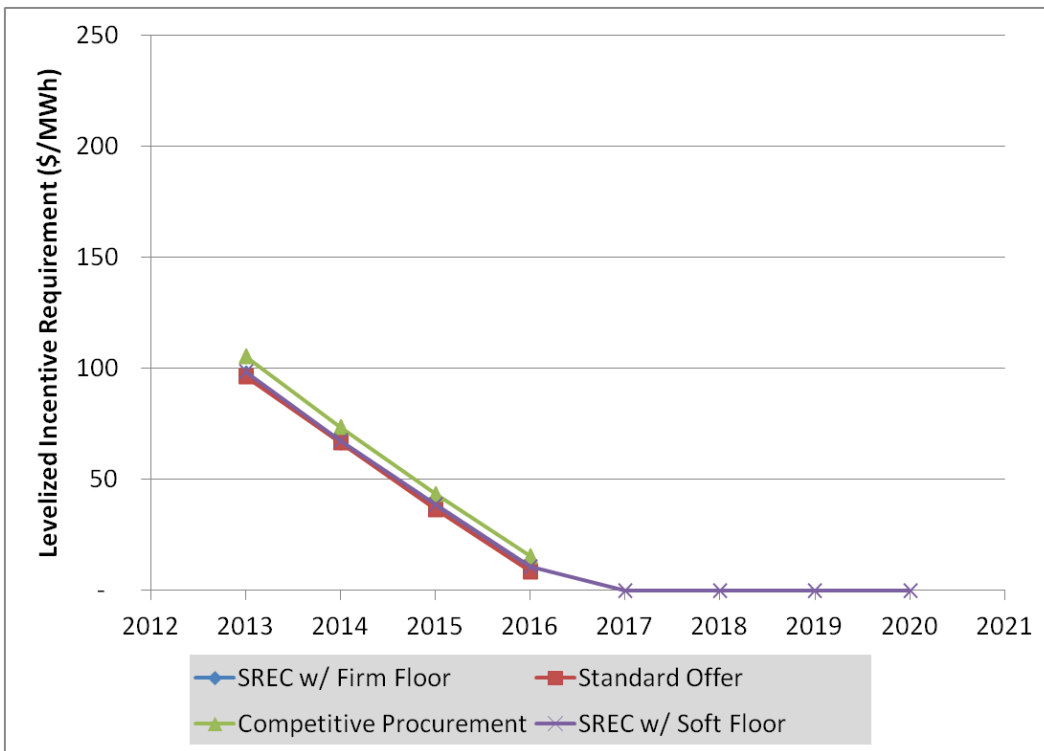**Figure 32: Incentive Requirement: Boston Edison (NSTAR), Ground Mounted 500+ kW**
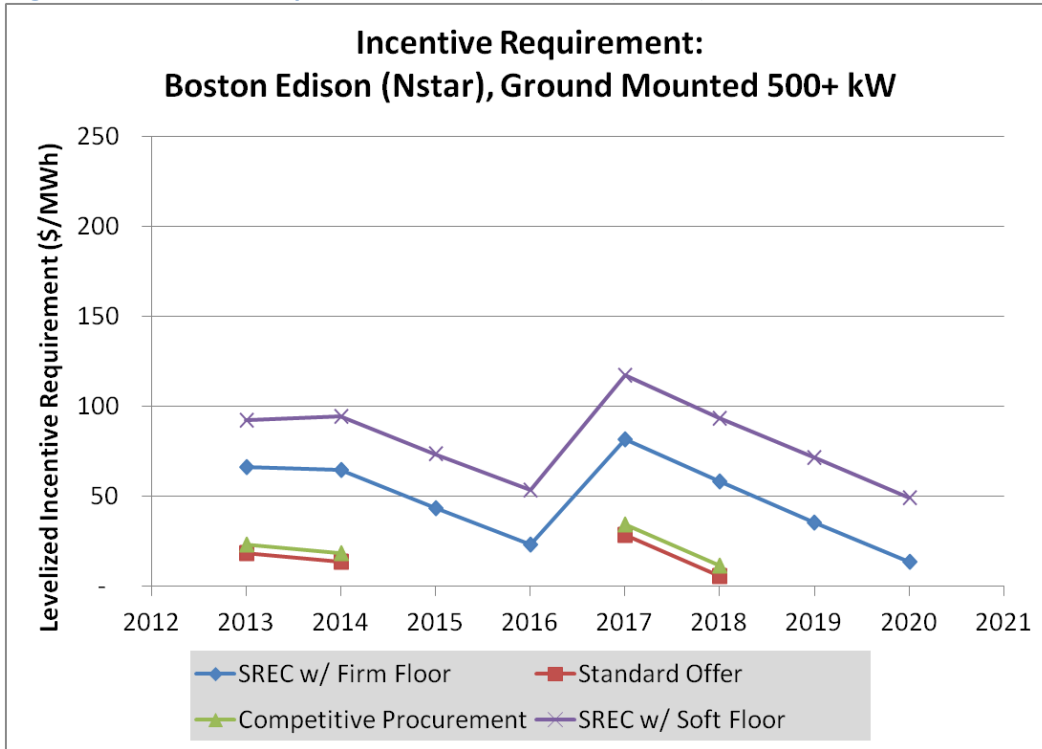
Figure 33: Incentive Requirement: Boston Edison (NSTAR), Landfill Mounted 500+ kW
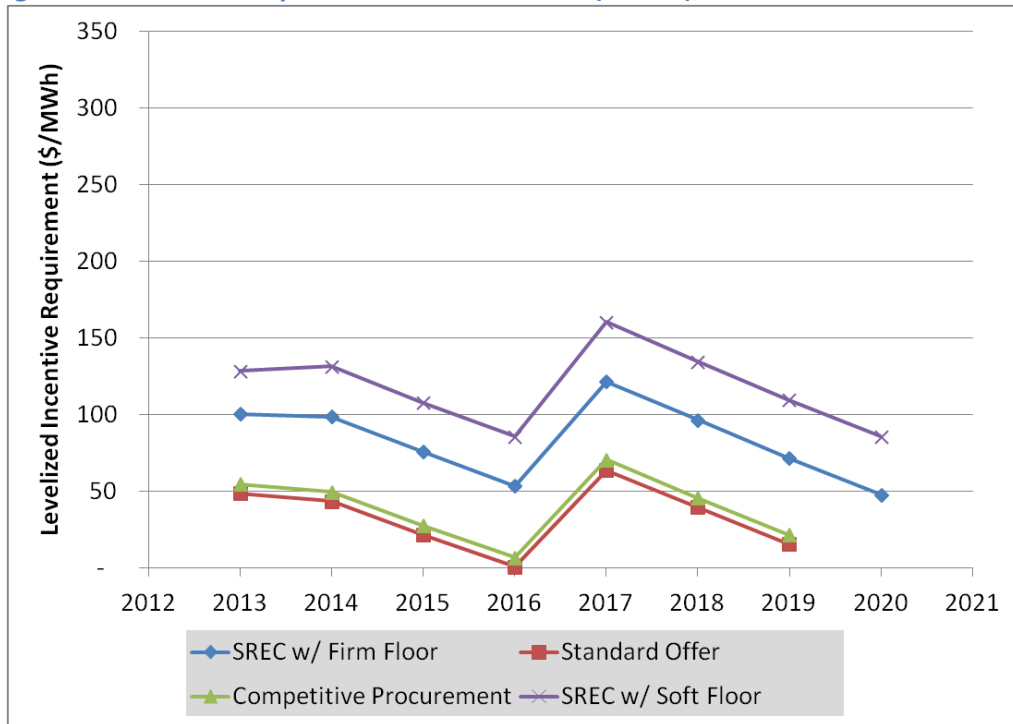
Figure 34: Incentive Requirement: Commonwealth Electric (NSTAR), Roof Mounted < 15 kW Residential
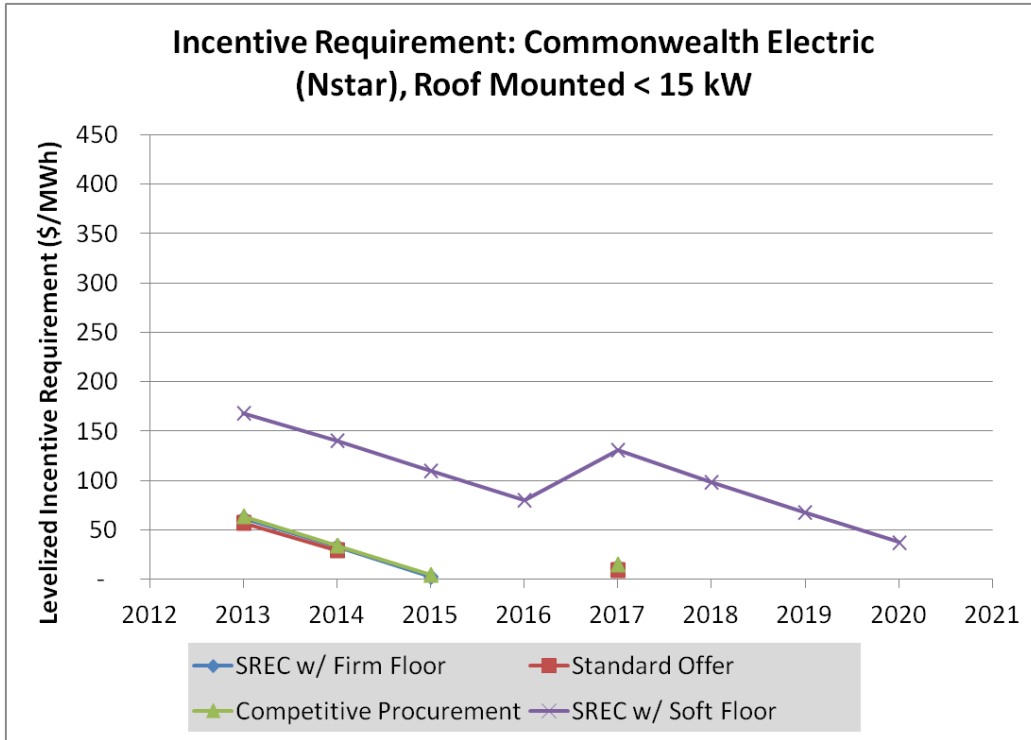
Figure 35: Incentive Requirement: Commonwealth Electric (NSTAR), Roof Mounted 15-500 kW

Figure 36: Incentive Requirement: Commonwealth Electric (NSTAR), Ground Mounted 500+ kW

Figure 37: Incentive Requirement: Commonwealth Electric (NSTAR), Landfill Mounted 500+ kW
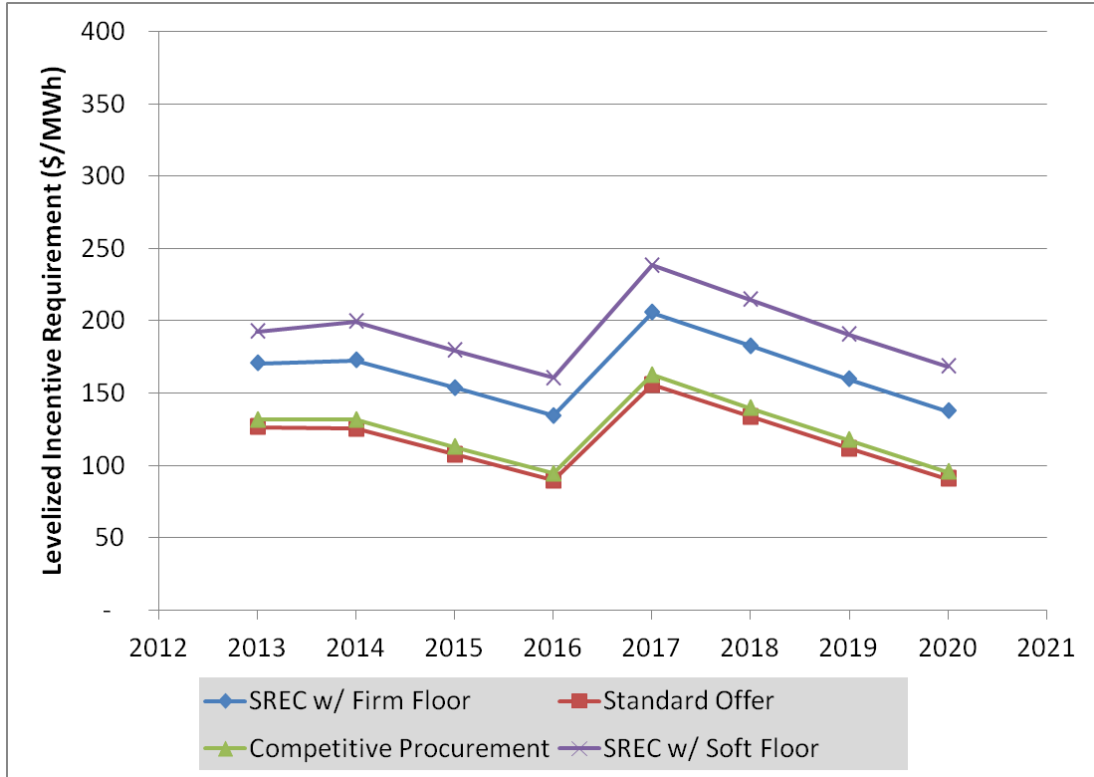
Public Ownership

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Figure 40: Incentive Requirement: Mass Electric (National Grid), Landfill Mounted 500+ kW

Figure 41: Incentive Requirement: WMECO, Roof Mounted 15-500 kW

Figure 42: Incentive Requirement: WMECO, Ground Mounted 500+ kW

Figure 43: Incentive Requirement: WMECO, Landfill Mounted 500+ kW
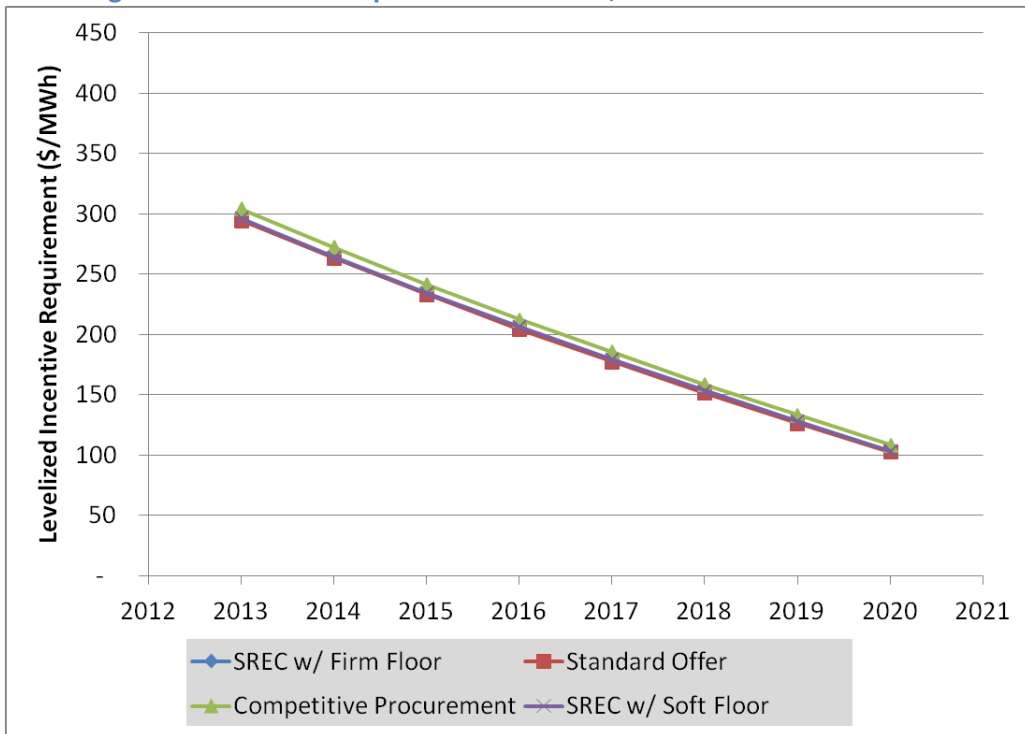
Figure 44: Incentive Requirement: Boston Edison (NSTAR), Roof Mounted 15-500 kW

Figure 45: Incentive Requirement: Boston Edison (NSTAR), Ground Mounted 500+ kW

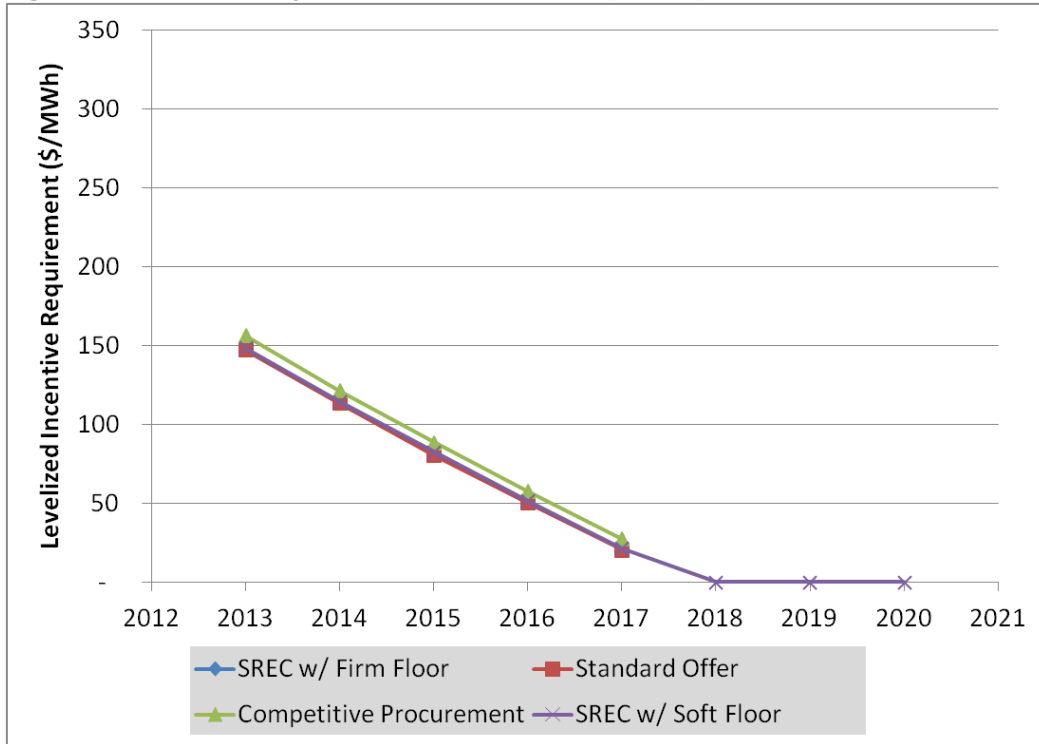**Figure 46: Incentive Requirement: Boston Edison (NSTAR), Landfill Mounted 500+ kW**

Figure 47: Incentive Requirement: Commonwealth Electric (NSTAR), Roof Mounted 15-500 kW
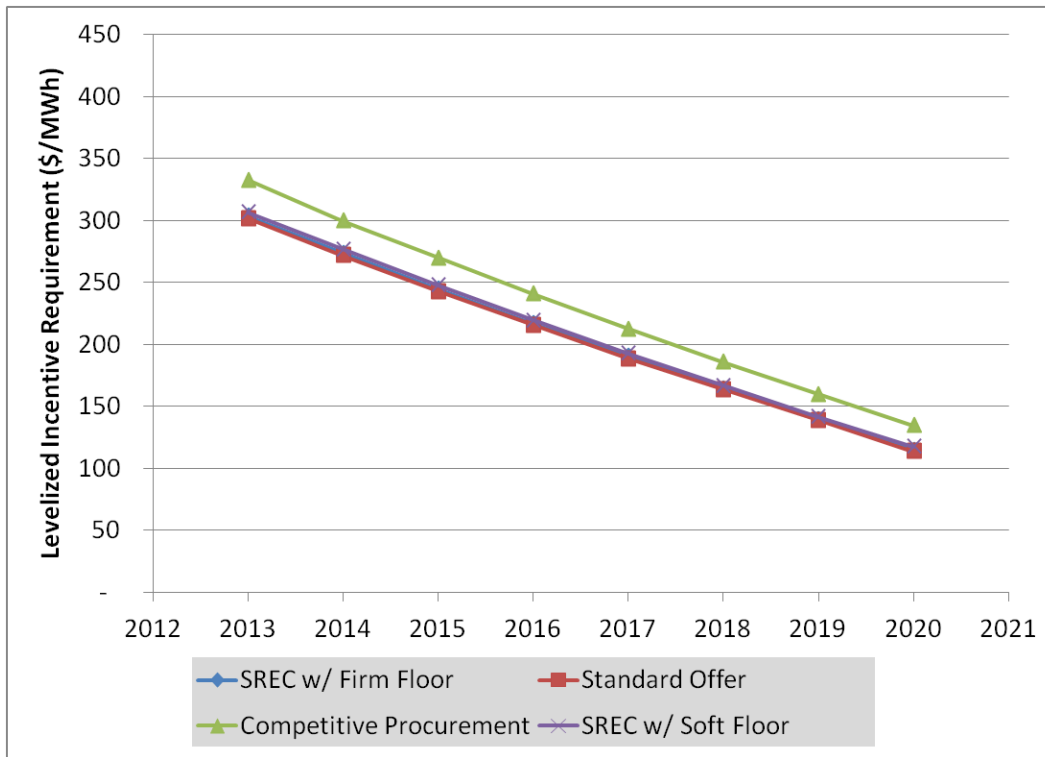

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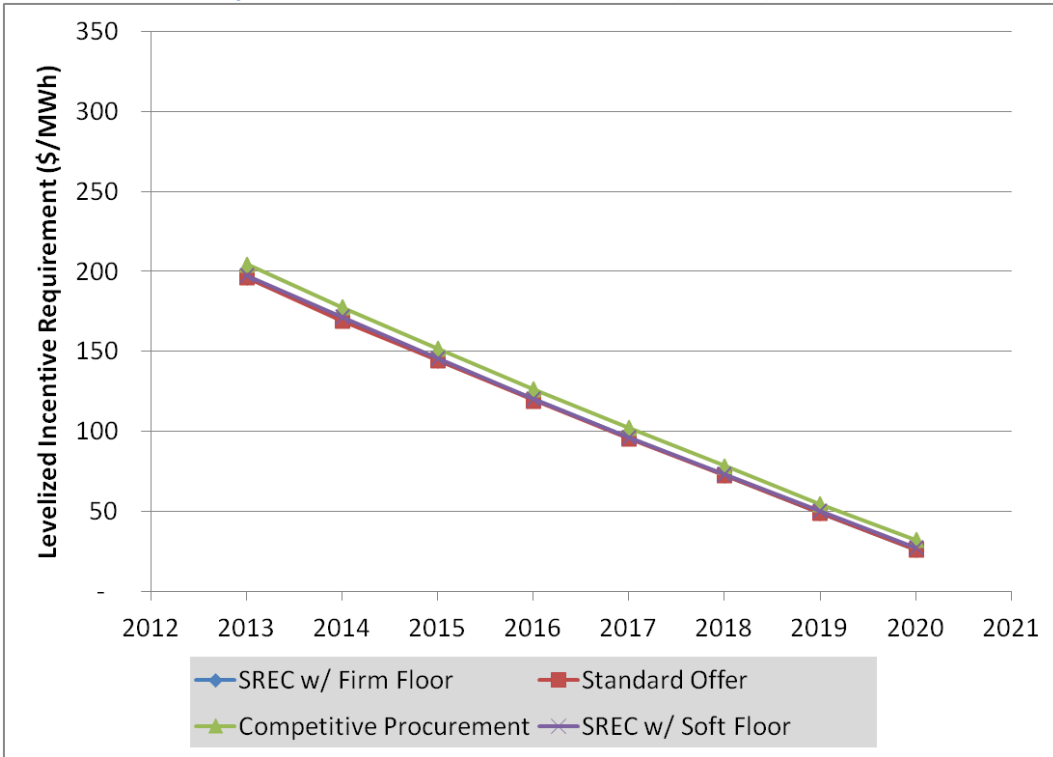**Figure 48: Incentive Requirement: Commonwealth Electric (NSTAR), Ground Mounted 500+ kW**

Figure 49: Incentive Requirement: Commonwealth Electric (NSTAR), Landfill Mounted 500+ kW