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Education:

Tufts University
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MA candidate in the Urban and Environmental Policy and Planning Department

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Willamette University
Salem, OR BA Spring 2005

Majors: Environmental Science; and Politics

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Manchester Community College
Manchester, CT AS Spring 2003

Major: General Studies

Connecticut School of Broadcasting
Farmington, CT Graduated Spring 1998

Professional Experience:

Vote Solar
Boston, MA October 2013 – Present

Manager of distributed solar generation policy research, development, and implementation for Vote Solar. Engage in related state, regional, and national regulatory processes.

Massachusetts Department of Public Utilities
Boston, MA June 2008 – October 2013

Senior economist for the Electric Power Division of the Massachusetts Department of Public Utilities ("DPU"). Primary focus at the DPU was all issues related to distributed generation, and renewable energy, including net metering, interconnection, and long-term contracts for renewable energy.

Massachusetts Technology Collaborative- Renewable Energy Trust
Westborough, MA January 2007 – December 2007

Policy intern for Fran Cummings. Assisted Mr. Cummings in policy development and implementation for the Massachusetts Renewable Energy Trust.

Tufts Institute of the Environment (TIE)
Medford, MA October 2005 - April 2006

Research Assistant for Professor Ann Rappaport.

Oregon Department of Energy
Salem, OR January 2005 – May 2005

Renewables Intern for Carl DeWitt. The primary focus of the research was to evaluate renewable portfolio standards from around the United States, and develop best practices for possible implementation in Oregon.

Connecticut General Assembly
Hartford, CT January 2001 – May 2001

Intern for Senator Martin Looney.

Testimony

Investigation by the Department of Public Utilities on its own motion as to the propriety of the rates and charges proposed by Massachusetts Electric Company and Nantucket Electric Company in their petition for approval of an increase in base distribution rates for electric service
Massachusetts Docket D.P.U. 15-155

In the Matter of the Application of Southern Maryland Electric Cooperative, Inc. for Authority to Revise Its Rates and Charges for Electricity Service and Certain Rate Design Charges
Maryland Case No.: 9396

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Maryland Case No.: 9361

Presentations

Distribution Network Policy Matters
Northeast Energy and Commerce Assc. March 2016

Appropriate Valuation Factors for Small DER
MD PSC (PC 40) October 2015

Electricity 101
Northeast Sustainable Energy Assc. March 2015

Evaluating the Benefits and Costs of Solar PV
MADRI Working Group May 2014

Interconnection and Net Metering in Massachusetts
Innovations in Clean Energy September 2012

Net Metering in Massachusetts & Community Solar
ASES Solar 2010 May 2010

Net Metering in Massachusetts
EUEC February 2010

Utility Ownership of Solar Generation in a Deregulated Market
EUEC February 2010

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A REGULATOR'S GUIDEBOOK: Calculating the Benefits and Costs of Distributed Solar Generation

Interstate Renewable Energy Council, Inc.

IREC

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Executive Summary

As distributed solar generation ("DSG") system prices continue to fall and this energy resource becomes more accessible thanks to financing options and regulatory programs, regulators, utilities and other stakeholders are increasingly interested in investigating DSG benefits and costs. Understandably, regulators seek to understand whether policies, such as net energy metering ("NEM"), put in place to encourage adoption of DSG are appropriate and cost-effective. This paper first offers lessons learned from the 16 regional and utility-specific DSG studies summarized in a recent review by the Rocky Mountain Institute ("RMI"),[1] and then proposes a standardized valuation methodology for public utility commissions to consider implementing in future studies.

As RMI's meta-study shows, recent DSG studies have varied widely due to differences in study assumptions, key parameters, and methodologies. A stark example came to light in early 2013 in Arizona, where two DSG benefit and cost studies were released in consecutive order by that State's largest utility and then by the solar industry. The utility-funded study showed a net solar value of less than four cents per kilowatt-hour ("kWh"), while the industry-funded study found a value in excess of 21 cents per kWh. A standard methodology would be helpful as legislators, regulators and the public attempt to determine whether to curtail or expand DSG policies.

Valuations vary by utility, but the authors contend that valuation methodologies should not. The authors suggest standardized approaches for the various benefits and costs, and explain how to calculate them regardless of the structure of the program or rate in which this valuation is used. Whether considering net NEM, value of solar tariffs, fixed-rate feed-in tariffs, or incentive programs, parties will always want to determine the value provided by DSG. The authors seek to fill that need, without endorsing any particular DSG policy in this paper.

Major Conclusions

Three conclusions stand out based on their potential to impact valuations:

- DSG primarily offsets combined-cycle natural gas facilities, which should be reflected in avoided energy costs.
- DSG installations are predictable and should be included in utility forecasts of capacity needs, so DSG should be credited with a capacity value upon interconnection.
- The societal benefits of DSG policies, such as job growth, health benefits and environmental benefits, should be included in valuations, as these were typically among the reasons for policy enactment in the first place.

[1] *A Review of Solar PV Benefit & Cost Studies* (RMI), July 2013 ("RMI 2013 Study"), *available at* http://www.rmi.org/elab_empower.

I. Introduction

There is an acute need for a standardized approach to distributed solar generation ("DSG") benefit and cost studies. In the first half of 2013, a steady flow of reports, news stories, workshops and conference panels have discussed whether to reform or repeal net energy metering ("NEM"), which is the bill credit arrangement that allows solar customers to receive full credit on their energy bills for any power they deliver to the grid.[2] The calls for change are founded on the claim that NEM customers who "zero out" their utility bill must not be paying their fair share for the utility infrastructure that they are using, and that those costs must have shifted to other, non-solar customers. Only a thorough benefit and cost analysis can provide regulators with an answer to whether this claim is valid in a given utility service area. As the simplicity and certainty of NEM have made it the vehicle for nearly all of the 400,000+ customer-sited solar arrays installed in the United States,[3] changes to such a successful policy should only be made based on careful analysis. This is especially so in light of a body of studies finding that solar customers may actually be subsidizing utilities and other customers.

The topic of NEM impacts on utility economics and on rates for non-solar customers seems to have risen to the top of utility priorities with the publication of an industry trade group report in January 2013 calling NEM "the largest near-term threat to the utility model."[4] Extrapolating from the current NEM penetration of just over 0.1% of U.S. energy generation to very high market penetration assumptions (e.g., if "everyone goes solar"), some have speculated that unchecked NEM growth will lead to a "utility death spiral." One Wall Street rating agency questioned the value of utility stocks in light of the continued success of NEM programs, claiming that it was "a scheme similar to net metering that led to the destabilization of the power markets in Spain in late 2008."[5]

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[2] NEM allows utility customers with renewable energy generators to offset part or all of their electric load, both at the time of generation and through kWh credits for any excess generation. This enables customers with solar arrays to take credit at night for excess energy generated during the day, for instance. Forty-three states have implemented NEM (*see* www.freeingthegrid.org for details on state NEM policies).

[3] Larry Sherwood, *U.S. Solar Market Trends 2012* (Interstate Renewable Energy Council), at p. 5 (316,000 photovoltaic installations connected to the grid at year-end 2012, with 95,000 in 2012 alone), July 2013, *available at* http://www.irecusa.org/wp-content/uploads/2013/07/Solar-Report-Final-July-2013-1.pdf. Forecasts for 2013 installations surpass 2012. *See, e.g., U.S. Solar Market Insight Report Q1 2013*, Greentech Media, Executive Summary, at p. 14, June 2013, *available at* http://www.greentechmedia.com/research/ussmi.

[4] Peter Kind, *Disruptive Challenges: Financial Implications and Strategic Responses to a Changing Retail Electric Business* (Edison Electric Institute), at p. 4, Jan. 2013.

[5] *Solar Panels Cast Shadow on U.S. Utility Rate Design* (FitchRatings), July 17, 2013, *available at* http://www.fitchratings.com/gws/en/fitchwire/fitchwirearticle/Solar-Panels-Cast?pr_id=796776. The piece was wrong on its facts. The Spanish model used a feed-in tariff ("FIT") based on solar energy costs and set at over US $0.60/kWh, leading to a massive build-out in a single year when solar prices dipped below the FIT rates. See *Spain's Solar Market Crash Offers a Cautionary Tale About Feed-In Tariffs*, N.Y. Times, Aug. 18, 2009, *available at* http://www.nytimes.com/gwire/2009/08/18/18greenwire-spains-solar-market-crash-offers-a-cautionary-88308.html?pagewanted=all (for up to 44 eurocent incentives, and using 0.711 average euro to U.S. dollar exchange rate in 2008, per IRS tables).

Numerous trade and industry publications have joined the chorus, with little indication that the rhetoric will abate anytime soon.[6]

DSG benefit and cost studies are important beyond the context of NEM. To address concerns about the cost-effectiveness of NEM, Austin Energy implemented the first Value of Solar Tariff ("VOST") in 2012, which is now under consideration in other jurisdictions. Under the Austin Energy approach, all of the customer's energy needs are provided by the utility, just as they would be if the customer did not have DSG, and the utility credits the residential solar customer for the value of all of the energy produced by the customer's solar array.[7] Though intended to offer a new approach to address the valuation issue, Austin Energy's VOST did little to quell the larger debate; indeed, this new policy highlights the fact that valuation is the key issue for any solar policy—NEM, VOST or otherwise.

Austin Energy's VOST rate, as initially calculated, was about three cents higher than retail rates, giving customers an even greater return than the NEM policy that the VOST replaced. However, as with NEM, discussions about "value of solar" rates have now turned to how to calculate the benefits of customer-generated energy. Claiming the use of their own VOST approach, City Public Service, the municipal utility serving San Antonio, Texas (just 80 miles from Austin) used an undisclosed, annualized value approach to conclude that the value of customer-sited energy from solar arrays was roughly half of the retail rate. A competing study for San Antonio, sponsored by Solar San Antonio and using publicly available data, showed twice that value.[8] As with NEM, the VOST approach is still subject to significant variation in valuation methodologies.

In early 2013, competing studies looking at DSG values for Arizona Public Service ("APS") kept the debate over valuation raging. APS funded a study that concluded DSG value was only 3.56 cents per kilowatt-hour ("kWh"), based on the present value of a kWh from DSG in the year 2025. Subsequently, APS filed an application to either change the rate schedule available to NEM customers or switch to a Feed-In Tariff ("FiT"), with both approaches relying on valuation in the range of 4 to 5.5 cents per kWh. At the same time, a solar industry-sponsored study found a 21 to 24 cent range for the value of each kWh of DSG, far exceeding costs, which it found to be in the range of 14 to 16 cents per kWh.[9] The lack of a consistent study approach drives the disparity in results.

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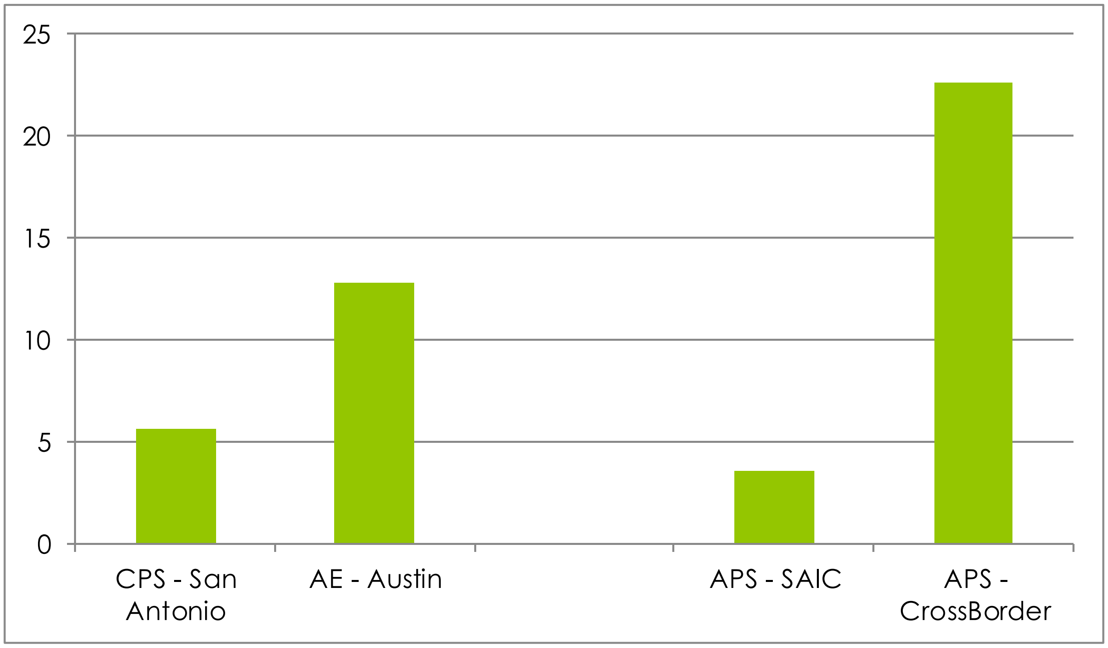
[6] *See* David Roberts, *Solar panels could destroy U.S. utilities, according to U.S. utilities*, Grist, April 2013, *available at* http://grist.org/climate-energy/solar-panels-could-destroy-u-s-utilities-according-to-u-s-utilities/; Herman Trabish, *Solar's Net Metering Under Attack*, GreenTech Media, May 2012, *available at* http://www.greentechmedia.com/articles/read/solars-net-metering-under-attack.
[7] *See* Austin Energy's Residential Solar Tariff, *available at* www.austinenergy.com/About%20Us/Rates/pdfs/Residential/ResidentialSolar.pdf (last accessed September 9, 2013).
[8] *See* N. Jones and B. Norris, *The Value of Distributed Solar Electric Generation to San Antonio*, March 2013 ("San Antonio Study"), *available at* www.solarsanantonio.org/wp-content/uploads/2013/04/Value-of-Solar-at-San-Antonio-03-13-2013.pdf.
[9] Arizona Corporation Commission Docket No. E-01345A-13-0248 regarding NEM valuation opened with APS's application in July, 2013, and is available at http://edocket.azcc.gov/. The May 2013 APS study prepared by SAIC is available at http://www.solarfuturearizona.com/2013SolarValueStudy.pdf. The May 2013 solar industry-sponsored study prepared by Crossborder Energy is available at http://www.solarfuturearizona.com/TheBenefitsandCostsofSolarDistributedGenerationforAPS.pdf.

Figure 1 displays the 150% difference between the Austin Energy and San Antonio City Public Service DSG valuations, alongside the 6X difference in values found in the two APS studies.

Figure 1: Disparate DSG Valuations in Texas Studies (cents/kWh).



The figure above shows that Austin Energy's latest valuation of 12.8 cents per kWh is 150% greater the 5.1 cent valuation by City Public Service in San Antonio, just 80 miles away. Even more dramatic is the difference in DSG values for APS, with 3.56 cents by the utility consultant and a range of 21.5 to 23.7 cents by the solar industry consultant.

Overview of a proposed standardized approach. This paper explains how to calculate the benefits and costs of DSG, regardless of the structure of the program or rate in which this valuation is used. Whether considering NEM, VOST, FiTs or incentive programs, parties will always want to understand DSG value. Indeed, accuracy in resource and energy valuation is the cornerstone of sound utility ratemaking and a critical element of economic efficiency. Fortunately, at least 16 studies of individual utilities or regions have been performed over the past several years, providing a backdrop for the types of benefits and costs to consider. While the variation in the purposes, assumptions and approaches in these studies has been wide, the body of published work is sufficient to draw some conclusions about best practices via a meta-analysis.

Rocky Mountain Institute ("RMI"), a Colorado-based not-for-profit research organization, looked at these 16 studies and summarized the range of valuations for each benefit and cost category in *A Review of Solar PV Benefit and Cost Studies* ("RMI 2013 Study"), providing a very useful tool for regulators determining whether a new study has considered all of the relevant benefits and costs. As well, an IREC-led report in early 2012 summarized these key benefits and costs and provided a generalized, high-level approach for their inclusion in any study ("Solar ABCs Report").[10] Together, the Solar ABCs Report and the RMI 2013 Study provide a detailed summation of efforts to date to assess the net benefits and costs of DSG.

This paper discusses various studies, but does not attempt to replicate RMI's thorough meta-analysis. Rather, this paper proposes *how* each benefit should be calculated and *why*. To assist state utility commissions and other regulators as they consider DSG valuation studies and the fate of NEM, VOST, or other programs or rate designs, we offer a set of recommended best practices regulators can use to ensure that a DSG benefit and cost study accurately measures the net impact of DSG.[11]

This paper synthesizes the prevalent and preferred methods of quantifying the categories of benefits and costs of DSG. One point of agreement is that DSG-related energy benefits are well accepted and are typically employed in cost-effectiveness testing, as well as in avoided cost calculations. Additional benefits and costs, related to capacity, transmission and distribution ("T&D") costs, line losses, ancillary services, fuel price impacts, market price impacts, environmental compliance costs, and administrative expenses are less uniformly treated in regulation and in the literature, and are addressed here in an effort to establish more commonality in approach. The quantification of societal benefits (beyond utility compliance costs) is also addressed. While typically not quantified in cost-effectiveness tests, these benefits—especially as related to evaluation of the risk associated with alternate resources—also merit more uniform treatment.

Organizationally, this paper covers the types of studies undertaken in relation to DSG valuation and overarching issues in DSG valuation studies, followed by the benefits and costs considered in various studies, the rationale for them, and the authors' recommendations on how to approach them.

> *The premise of this paper is that while calculated values will differ from one utility to the next, the approach used to calculate the benefits and costs of distributed solar generation should be uniform.*

II. DSG Benefit and Cost Studies

A history of DSG benefit and cost studies. There have been an increasing number of studies conducted and published over the past 10-15 years addressing the value of DSG and other distributed energy resources. The first comprehensive effort to

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[10] J. Keyes and J. Wiedman, *A Generalized Approach to Assessing the Rate Impacts of Net Energy Metering* (Solar America Board of Codes and Standards), January 2012 ("SolarABCs Report"), *available at* www.solarabcs.org/about/publications/reports/rateimpact.

[11] In addition, the Interstate Renewable Energy Council. Inc. ("IREC") is proactively working with state utility commissions to ask these questions before studies are undertaken, with the expectation that having clarified the assumptions, commissioners will be more confident in the results.

characterize the value of distributed energy resources was *Small Is Profitable: The Hidden Economic Benefits of Making Electrical Resources the Right Size*, published by RMI in 2002. Drawing from hundreds of sources, pilot project reports, and studies, *Small Is Profitable* set the stage for more specific technology-based studies, including the NEM cost-benefit studies and solar valuation studies that followed. Studies specific to DSG systems have appeared with increasing frequency since the Vote Solar Initiative published Ed Smeloff's *Quantifying the Benefits of Solar Power for California* in 2005 and Clean Power Research ("CPR") published its evaluation of *The Value of Solar to Austin Energy and the City of Austin* in 2006.

The reasons behind the appearance of these studies are several. DSG represents an increasingly affordable, interconnected form of distributed generation, creating the potential for significant penetration of small-scale generation into grids generally built around a central station model. In addition, economic and policy pressure on rebates and other mechanisms to foster DSG penetration has increased interest in improving understanding of the DSG value proposition. Utilities, policymakers, regulators, advocates, and service and hardware providers share a common interest in understanding what benefits and costs might be associated with such increased deployment of DSG, and whether net benefits outweigh net costs under a variety of deployment and analysis scenarios.

Many recent DSG valuation studies have been cost-effectiveness analyses of NEM policies for a given utility or group of utilities. NEM has proven to be one of the major drivers of distributed generation in the United States; 43 states and the District of Columbia feature some form of NEM.[12] The success of NEM as a policy to drive distributed generation market growth has caused several states to examine the impact that the policy has on other non-participating ratepayers. Efforts are currently underway in California, Arizona, Hawaii, Colorado, Nevada, North Carolina and Georgia to quantify the benefits and costs of the policy in order to inform the appropriate level of support for distributed energy generation, particularly rooftop solar photovoltaic ("PV") generation. Other states may follow soon, even those with relatively few DSG installations; for example, the Louisiana Public Service Commission indicated that it would launch a cost-benefit analysis for net-metered systems.

Another major use for DSG value analysis is in resource planning and other regulatory proceedings. In December 2012, Lawrence Berkeley National Laboratory ("LBNL") published a review of how several utilities account for solar resources in *An Evaluation of Solar Valuation Methods Used in Utility Planning and Procurement Processes.*[13] At this writing, Integrated Resource Plan ("IRP"), avoided cost, or renewable plan dockets are, or soon will be, underway at several utilities[14] where the value of DSG is directly at issue. In addition, the state of Minnesota has recently adopted legislation that establishes a

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[12] *See* Database of State Incentives for Renewables and Energy Efficiency ("DSIRE"): Summary Maps – Net Metering Policies, *available at* www.dsireusa.org (last accessed Aug. 18. 2013).

[13] Andrew Mills & Ryan Wiser, *An Evaluation of Solar Valuation Methods Used in Utility Planning and Procurement Processes* (Lawrence Berkeley National Laboratory), LBNL-5933E, December 2012 ("LBNL Utility Solar Study 2012"), *available at* http://emp.lbl.gov/publications/evaluation-solar-valuation-methods-used-utility-planning-and-procurement-processes.

[14] *See, e.g.,* Georgia Public Service Commission Docket No. 36989 (Georgia Power Rate Case); North Carolina Utilities Commission Docket No. E-100, Sub 136 (Biennial Avoided Cost); Colorado Public Utilities Commission Docket No. 13A-0836E (Public Service Company Compliance Plan).

Value of Solar rate for DSG.[15] The authors anticipate that additional valuation studies will result from one or more of these proceedings.

As of this writing, relatively few jurisdictions have conducted full cost-effectiveness studies for DSG and fewer still provide sufficient detail to guide development of a common methodology. CPR's Austin Energy study, updated in 2012, established an approach that has been applied in other regions, including a recent study on the value of DSG in Pennsylvania and New Jersey.[16] The California Public Utilities Commission ("CPUC") and APS commissioned comprehensive studies in 2009; both commissioned revised studies in 2013.[17] In January 2013, Vermont's Public Service Department[18] completed a cost-benefit analysis of NEM policy.

While not identical in structure, these works typify the recent reports and illustrate some commonalities in approaching the valuation of distributed energy. NEM-specific studies include the 2009 California Energy and Environmental Economics ("E3") Study, Crossborder Energy's 2013 updated look at that E3 study,[19] Crossborder Energy's 2013 analysis of DSG cost-effectiveness in Arizona,[20] and the Public Service Department's own analysis for Vermont.

As noted earlier, this paper complements IREC's recent publication, *A Generalized Approach to Assessing the Rate Impacts of Net Energy Metering*.[21] That paper reviews the DSG valuation studies that had been published to date and provides general approaches to calculating the widely recognized categories of benefits and costs that are relevant to the consideration of the cost-effectiveness of VOST, NEM, and other policy mechanisms impacting DSG. The intent of this examination is to dive deeper, find more common ground for discussion and foster greater consistency in how these values are determined across jurisdictions.

Also as noted earlier, this paper benefits from analysis recently published by RMI, entitled *A Review of Solar PV Benefit and cost Studies*.[22] That report reviews 16 studies in a meta-analysis that examines methodologies and assumptions in great detail. Figure 2 is from that study, and characterizes the differences and similarities in the studies. As

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[15] Minn. Stat. § 216B.164, subd. 10 (2013): Chapter 85--H.F. No. 729, Article 9, Distributed Generation, Section 10.

[16] Richard Perez, Thomas Hoff, and Benjamin Norris, *The Value of Distributed Solar Electric Generation to New Jersey and Pennsylvania,* 2012 ("CPR 2012 MSEIA Study"), *available at* http://communitypowernetwork.com/sites/default/files/MSEIA-Final-Benefits-of-Solar-Report-2012-11-01.pdf.

[17] APS studies: *Distributed Renewable Energy Operating Impacts and Valuation Study*, RW Beck, Jan. 2009, available at http://www.solarfuturearizona.com/SolarDEStudy.pdf; *2013 Updated Solar PV Value Report*, SAIC, May 2013, available at http://www.solarfuturearizona.com/2013SolarValueStudy.pdf.
CPUC studies conducted by Energy and Environment Economics ("E3"):
http://www.cpuc.ca.gov/PUC/energy/Solar/nem_cost_effectiveness_evaluation.htm.

[18] *Evaluation of Net Metering in Vermont Conducted Pursuant to Act 125 of 2012*, January 15, 2013 ("Vermont Study"), *available at* www.leg.state.vt.us/reports/2013ExternalReports/285580.pdf.

[19] Thomas Beach and Patrick McGuire, *Evaluating the Benefits and Costs of Net Energy Metering in California* (Vote Solar Initiative), 2013 ("Crossborder 2013 California Study"), *available at* http://www.seia.org/research-resources/evaluating-benefits-costs-net-energy-metering-california.

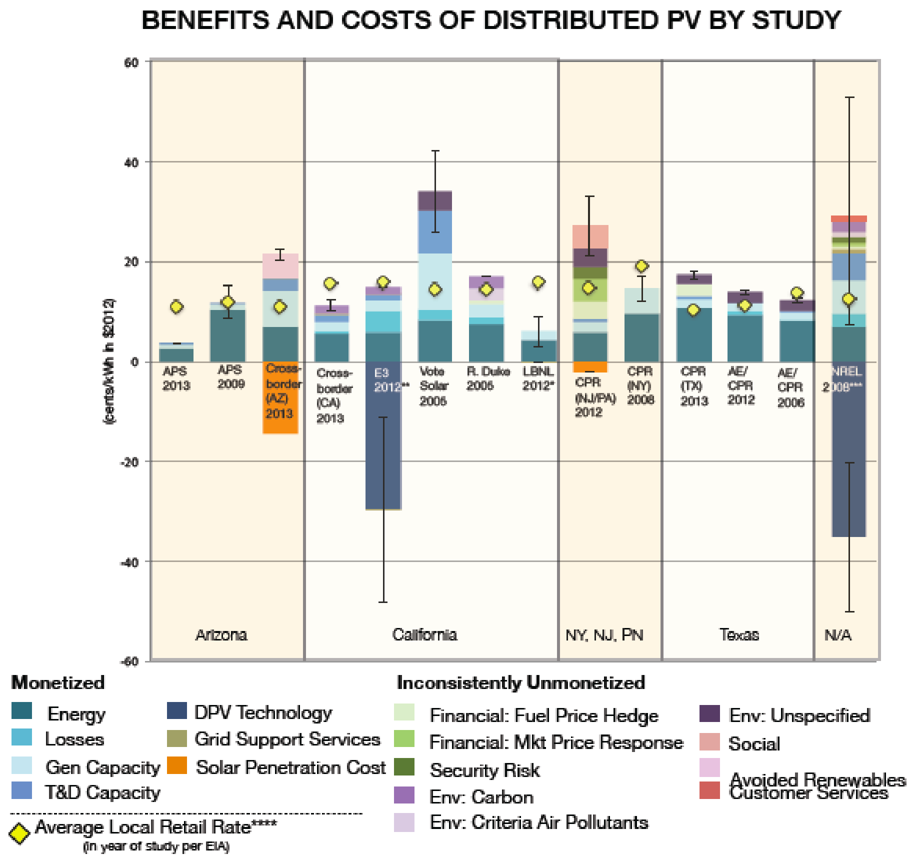
[20] Thomas Beach and Patrick McGuire, *The Benefits and Costs of Solar Distributed Generation for Arizona Public Service* (Vote Solar Initiative), at p.12, 2013 ("Crossborder 2013 Arizona Study"), *available at* http://www.solarfuturearizona.com/TheBenefitsandCostsofSolarDistributedGenerationforAPS.pdf.

[21] *See* SolarABCs Report, *supra*, footnote 10.

[22] *See* RMI 2013 Study, *supra*, footnote 1.

well as considering benefits and costs the RMI 2013 Study points out that the various studies differ significantly in the amount of DSG penetration considered, which can drastically impact values. Another important differentiator is whether the studies are based on high-level, often secondary, review of benefits and costs, or whether they rely on more granular and detailed modeling of impacts.[23]

Figure 2: Rocky Mountain Institute Summary of DSG Benefits and Costs



The RMI 2013 Study figure is reprinted here to make three important points. First and foremost, the calculated benefits often exceed residential retail rates, shown in the figure with diamonds, implying that NEM would not entail a subsidy flowing from non-solar to solar customers. Second, commercial customers almost always have unbundled rates and NEM has minimal impact on their demand charges because they still have demand after the sun sets. That means that DSG benefits compared to commercial customer energy rates would be strongly positive based on almost all of these studies. And third, costs are accounted for in varying ways: three studies show costs including lost retail rate payments, with large bars below the zero line indicating total costs, one shows costs other than retail rate payments (CPR NJ/PA), and the rest include costs as a deduction within the benefits calculation. As an overarching point,

[23] *Id.* at p. 21.

the RMI 2013 Study figure confirms that there is no single standard DSG valuation methodology today.

Types of Studies. Distributed solar valuation requires quantitative analysis of a wide range of data in an organized way. Fortunately, there are abundant existing approaches that can contribute to estimation of DSG value. This section briefly introduces the two major types of studies that underlie DSG valuation. The first category of studies is input and production cost models. These have general application in the utility industry in the comparison of resource alternatives. The second category, DSG-specific studies, includes three sub-types, depending on the purpose for which the study was conducted. In practice, most DSG-specific studies rely on inputs from input and production cost models.

A. Input and Production Cost Models

Utility planners and industry experts rely on a wide range of models and analytical tools for calculating costs associated with generation and systems. Power flow, dispatch, and planning models all provide input to the financial models used to evaluate DSG cost effectiveness and value. While detailed treatment of the utility models providing input to the DSG models is beyond the scope of this paper, they impact the DSG models and need to be understood. Often, these utility models are deemed proprietary, creating "black box" solutions regarding what generation is needed and when. Among the most critical decisions made at this juncture is whether the generation that will be offset by DSG is a relatively efficient natural gas combined-cycle combustion turbine ("CCGT")or a less efficient single cycle "peaker" plant running on natural gas, or some combination of the two.

As most of the gas-fired energy delivered by utilities comes from CCGTs, and peakers will still be needed to handle changes in load, models should reflect that DSG is primarily offsetting CCGTs. However, the APS 2013 study is an example in which the input model results are confounding, and there is no way to review the black box solution. Oddly, APS found that baseload coal would be displaced for part of the year. We believe that such an example deserves more careful study; it is a nearly universal truth that coal plants are run as much as possible. While many coal plants have been shut down in the past decade, those that remain are typically only curtailed for maintenance. Regulators should consider whether input assumptions such as coal or nuclear displacement are reasonable, particularly if the results are based on proprietary, opaque modeling.

Capacity needs in planning models are typically forecasted several years in the future and, because of the legacy of the central station utility plant paradigm, in large increments of capacity. These so-called "lumpy" capacity investments generally overshoot capacity requirements in order to ensure resource adequacy in the face of multi-year development lead times. As a result, the opportunity for DSG to provide useful capacity is generally seen as too little and too early. For example, a typical utility resource plan might state that capacity is adequate until the year 2018, at which time the company forecasts a need for an additional 200 megawatts ("MW") of generation capacity. In such a situation, traditional resource planning and avoided cost estimates assign no capacity value to DSG installed on customer roofs before 2018, and none in

2018 unless the systems provide the equivalent to 200 MW of capacity. This ignores the benefit of DSG's modularity—the utility does not need 200 MW in 2018, at that point it only starts to need more than it already has available. DSG can provide for that capacity through incremental installations starting in 2018. Likewise, if the utility has projects under development prior to 2018, it could have deferred or avoided some of that need if it had accurately predicted and valued DSG installations.

Today, many input and production cost planning models include the opportunity to adjust assumptions about customer adoption of DSG (and energy efficiency), which assume that those resources are going to play a role in the utility's near term capacity requirements. With these adjustments, the in-service requirement date can possibly be deferred, generating both energy and capacity savings attributable to the distributed resources. Accordingly, models that do not address DSG installations are inadequate and could lead to costly overbuilding and, given planning and construction lead times associated with large plants, premature expenditure of development costs.

B. DSG-Specific Studies

DSG-specific studies often start with inputs from the models just described. These studies are themselves usually of three types:

Studies of studies. Like this white paper, these studies start with work conducted by one or more experts and organize the information and data in a form that addresses questions of interest. In some cases, the authors report the results and the source conditions for the data. In others, study authors attempt to adjust the results for different local conditions. The RMI 2013 Study on solar PV reports the results of 16 different studies spanning some eight years. These studies provide useful introductions to the emerging discipline and demonstrate the ways in which differences in assumptions, methodologies, and underlying data can impact outcomes. In addition, when adjusting for outlier conditions, the studies can demonstrate where there exists relatively strong coherence in approach and results.

Cost-Benefit Analysis studies. Cost-benefit studies focus on using avoided cost methodologies and cost-benefit test approaches to review large-scale DSG initiatives and programs. They seek to answer the question of whether total costs or total benefits are greater over a specified period of time. For these studies, forward-looking cost estimates for DSG interconnection, lost revenues, avoided RPS costs, and incentive programs are important inputs. The best-known examples of this study approach were conducted by E3, reviewing the California Solar Initiative and NEM programs, and those by Crossborder Energy, reviewing the E3 reports. Most of the studies reviewed by the RMI 2013 Study are of this sort. There are several cost-benefit analysis varietals, as described in the California Standard Practice Manual and summarized in the box below.

Value of Solar studies. Smeloff and CPR pioneered the "value of solar" genre of study. As the name implies, this study approach focuses on using avoided cost and financial analysis methods in discerning the future investment value of distributed solar to the utility, ratepayers, and society. Generally, these evaluations ignore utility lost revenues, instead focusing on valuation that can be used in designing and setting incentive levels, program limits, and other features of utility DSG programs. The studies stop short of rate or tariff design features, and as a result, do not typically address lost revenue issues. Perhaps best known is the Austin Energy Value of Solar study conducted by CPR in 2006 and updated in 2012.[24]

With reference to the California Standard Practice Manual study descriptions summarized in the prior box, the type of test that the authors suggest in this paper is a blend of the Ratepayer Impact Measure ("RIM") and Societal Cost Test ("SCT") approaches. The RIM test addresses the impact on non-participating ratepayers in terms of how benefits and costs impact the utility and are passed along to those ratepayers. That necessarily does not account for the participating ratepayers' outlay for DSG systems, nor should it. The SCT approach looks at whether it is a good idea for society as a whole to pursue a policy, and includes participating ratepayers' investment in DSG systems. The authors contend that the participants' investment is outside of the scope of the appropriate investigation. The goal should be to determine whether non-participants have a net benefit from the installation of DSG systems. As the job creation, health and environmental benefits accrue to non-participants just as much as they accrue to participants, there is no apparent reason why societal benefits should not be included. In its consideration of benefits, this approach aligns with the VOST methodology which aims to include all benefits that can reasonably be quantified and assigned to utility operations.

Utilities often object, stating that valuing societal benefits conflates customers with citizens, and note that utility rates must be based on costs directly impacting utilities. By this line of reasoning, job creation and health benefits may be the basis of legislative policies supportive of DSG, but should not be considered when developing DSG tariffs. We are reluctant to accept an artificial division between citizens and utility customers; the overlap is complete for most benefits and costs. Moreover, a major reason for establishing NEM, VOST or other DSG programs is primarily related to the same broad societal benefits that drive utility regulatory systems—economic efficiency, and rates and services in the public interest—so those benefits should be considered in any programmatic or policy analysis.

Recommendation: Use a blend of the Ratepayer Impact Measure ("RIM") and Societal Cost Test ("SCT") Cost-Benefit Tests

[24] Author K. Rábago, while at Austin Energy, helped establish the nations' first VOST. *See* K. Rábago, *The Value of Solar Rate: Designing an Improved Residential Solar Tariff*, Solar Industry, at p. 20, Feb. 2013, *available at* http://solarindustrymag.com/digitaleditions/Main.php?MagID=3&MagNo=59.

Cost-Benefit Tests

The California Standard Practice Manual is used for economic analysis of demand-side management ("DSM") programs in California. The cost-benefit tests in the Standard Practice Manual have also been used to evaluate DSG value, most notably in California, where the tests have been applied to a review of the cost effectiveness of the California Solar Initiative. The various tests differ in the perspective from which cost effectiveness is assessed.

- ***Participant Cost Test* ("PCT").** Measures benefits and costs to program participants.
- ***Ratepayer Impact Measure ("RIM") Test.*** Measures changes in electric service rates due to changes in utility revenues and costs resulting from the assessed program.
- ***Program Administrator Cost Test ("PACT").*** Measures the benefits and costs to the program administrator, without consideration of the effect on actual revenues. This test differs from the RIM test in that it considers only the revenue requirement, ignoring changes in revenue collection, typically called "lost revenues."
- ***Total Resources Cost Test ("TRC").*** Measures the total net economic effects of the program, including both participants' and program administrator's benefits and costs, without regard to who incurs the costs or receives the benefits. For a utility-specific program, the test can be thought of as measuring the overall economic welfare over the entire utility service territory.
- ***Societal Cost Test ("SCT").*** The SCT is similar to the TRC, but broadens the universe of affected individuals to society as a whole, rather than just those in the program administrator territory. The SCT is also a vehicle for consideration of non-monetized externalities, such as induced economic development effects, which are not considered in the TRC.

III. Key Structural Issues for DSG Benefit and Cost Studies

Underlying study assumptions and major study components. The evaluation of the cost-effectiveness of a given DSG policy, particularly NEM, is a complex undertaking with many potential moving parts. Before delving into the specific benefits and costs, it is important to recognize that the ultimate outcome of the analysis is highly dependent on the base financial and framework assumptions that go into the effort. Much of the work involves forecasting—estimating the future benefits and costs, performance, and cumulative impacts associated with increasing penetration of distributed generation into the electric grid. It is important to develop a common set of base assumptions that reflect the resource being studied and to be as transparent as possible about these assumptions when reporting the results of the analysis. At the outset of a study, it is important to define these structural parameters. Below we present key questions for regulators to explore at the onset of a study:

Q1: WHAT DISCOUNT RATE WILL BE USED?

The discount rate should reflect how society evaluates costs over time. Utilities use a discount rate based on the time value of money, using the rate of return available for investments with similarly low risk, now in the 6% to 9% range. However, society may prefer the use of a lower discount rate, closer to the rate of inflation. The difference is important. High discount rates improve the evaluation of resources with continuously escalating or high end-of-life costs. For instance, an 8% discount rate may favor a natural gas generator because much of the cost (the fuel, operation and maintenance) to run the generator is incurred over the life of the generator, while the cost of DSG is almost entirely at the front end. A low discount rate improves the valuation of resources with high initial costs and low or zero end-of-life costs. The same analysis based on a 3% inflation rate may favor DSG resources, as there are no fuel costs over time and the operations and maintenance ("O&M") costs are low because there are fewer or no moving parts. While the utility's discount rate is appropriate when considering utility procurement because those funds could be invested elsewhere at competitive rates, the utility is not procuring the DSG resources in the case of NEM, VOST or FiT arrangements. It is worth questioning whether the future benefits of DSG resources should be heavily discounted, based on the utility's cost of capital, when the customer (or a third party owning a system at the customer's site) is making the investment. As utility valuation techniques improve, is it reasonable to discount future benefits and costs by the inflation rate rather than the utility's cost of capital.

Recommendation: We recommend using a lower discount rate for DSG than a typical utility discount rate to account for differences in DSG economics.

Q2: WHAT IS BEING CONSIDERED – ALL GENERATION OR EXPORTS ONLY?

Under NEM, utility customers can take advantage of a federal law[25] allowing for on-site generation to offset consumption, with the opportunity to sell excess generation to the utility at the utility's avoided cost. Because the customer has a right to avoid any and all consumption from the utility, studies of NEM cost-effectiveness will often look only at the utility cost associated with exports to the grid. The assumption under NEM is effectively that at or below the total consumption level, the value of offset consumption is the retail rate. This valuation is supported by the concept behind cost-of-service rate regulation—that the retail rate is the accumulation of costs to generate and deliver energy for the customer.[26] Note that to the extent that NEM benefits are calculated to

[25] *See* Public Utility Regulatory Policies Act ("PURPA"), 16 U.S.C. *et seq.*
[26] VOST studies, on the other hand, presume a difference between the value of generation at or near the point of consumption and the level of the rate. That is, the customer with DSG may well be generating electricity of greater value than that being provided by the utility.

outweigh costs, consideration of all generation amplifies the calculated net benefit. However, if NEM costs outweigh benefits, the opposite is true.

Recommendation: We recommend assessing only DSG exports to the grid.

Q3: OVER WHAT TIMEFRAME WILL THE STUDY EXAMINE THE BENEFITS AND COSTS OF DSG?

Utility planners routinely consider the lifecycle benefits and costs of traditional utility generators, typically over a period in excess of 30 years. Solar arrays have no moving parts and are generally expected to last for at least 30 years, with much less maintenance than fossil-fired generation. Solar module warranties are typically for 25 years, and many of the earliest modules from the 1960s and 1970s are still operational, indicating that modules in production today should last for at least 30 years. This useful life assumption creates some data challenges, as utilities often plan over shorter time horizons (10-20 years) in terms of estimating load growth and the resources necessary to meet that load. As described below, methods can be used to estimate the value in future years that interpolate between current market prices or knowledge, and the most forward market price available or data that can accurately be estimated, just as planners do for fossil-fired generators that are expected to last for decades.

Recommendation: We suggest that the most appropriate timeframe for evaluating DSG and related policy is 30 years, as that matches the currently anticipated life span of the technology.

Q4: WHAT DOES UTILITY LOAD LOOK LIKE IN THE FUTURE?

Key to determining the value of DSG is a reasonable expectation of what customer loads will look like in the future, as much of the value of distributed resources derives from the utility's ability to plan around customer-owned generation. Other DSG rate or program options involving sale of all output to the utility do not reduce utility loads, as customer facilities contribute to the available capacity of utility resources as small contracted generators.

Recommendation: Given that NEM resources are interconnected behind customer meters, and result in lower utility loads, we recommend that the assigned capacity value of the distributed systems reflect the fact that the utility can plan for lower loads than it otherwise would have.

Q5: WHAT LEVEL OF MARKET PENETRATION FOR DSG IS ASSUMED IN THE FUTURE?

Many benefits and costs are sensitive to how much customer-owned generation capacity is on the grid. Most studies assume current, low penetration rates. Several of the studies consider higher penetration levels, as well, typically out to 15% or 20% of peak load, with some outlier studies looking at 30% and 40% penetration levels. In a high-penetration scenario, the utility may face higher integration expenses that might undermine the specific infrastructure benefits of distributed generation. Studies that address the issue often find that marginal capacity benefits decline with high penetration.

On the other hand, some studies such as those by APS, conclude that capacity benefits are dependent on having enough DSG to offset the next natural gas generator, and therefore that there are no capacity benefits in low-penetration scenarios. Market penetration estimates should also be reasonable in light of current supply chain capacity and local market conditions. Generally, the most important penetration level to consider for policy purposes is the next increment. If a utility currently has 0.1% of its needs met by DSG and a study shows that growth to 5% is cost-effective, but growth to 40% is not, then it would be economically efficient to allow the program to grow to 5% and then be reevaluated.

Recommendation: We recommend the establishment of an expected level of DSG penetration, and the development of low and high sensitivities to consider the full range of future impacts.

Q6: WHAT MODELS ARE USED TO PROVIDE ANALYTICAL INPUTS?

Analysts have used a wide variety of tools to calculate the benefits and costs of DSG. There is almost no commonality at the model level, even though many of the analyses address similar or identical issues. Several studies use some version of investment and dispatch models in order to determine which resources are displaced by solar and the resulting impacts. As noted earlier, utility DSG studies have often relied on proprietary models for these inputs. The fact that CPR and Professor Richard Perez[27] have published a number of studies creates some commonality among those studies, but over time, even the CPR approaches have evolved as tools have been improved.

Recommendation: We suggest that transparent input models accessible to all stakeholders are the proper foundation for confidence and utility of DSG studies. If necessary, non-disclosure agreements can be used to overcome data sharing sensitivities.

Q7: WHAT GEOGRAPHIC BOUNDARIES ARE ASSUMED IN THE ANALYSIS?

Value of solar analysis is heavily influenced by local resource and market conditions. Most published studies are geographically scoped at the state, service territory, or interconnected region level. Given its leadership in solar deployment, California also leads as the subject of studies and as a data source. Some studies relating to economic development and environmental impacts use a national and regional scope.

Recommendation: We suggest that it is important to account for the range in local values that characterize the broader geographical area selected for the study. In some cases, quantification according to similar geographical sub-regions may be appropriate.

Q8: WHAT SYSTEM BOUNDARIES ARE ASSUMED?

The majority of studies consider benefits and costs in the generation, transmission, and distribution portions of the system. Of the studies that consider environmental impacts,

[27] Richard Perez is a Research Professor at the University at Albany-SUNY.

most only look at avoided utility environmental compliance costs at the generation level.

Recommendation: We recommend considering impacts associated with adjacent utility systems, especially at higher (above 10%) penetration levels of DSG.[28]

Q9: FROM WHOSE PERSPECTIVE ARE BENEFITS AND COSTS MEASURED?
Nearly all the studies consider impacts from the perspective of the utility and ratepayers. Several also consider customer and societal benefit and costs. Cost-benefit studies apply California Standard Practice Manual tests for Demand Side Management, discussed earlier.

Recommendation: We suggest that rate impacts and societal benefits and costs should be assessed.

Q10: ARE BENEFITS AND COSTS ESTIMATED ON AN ANNUALIZED OR LEVELIZED BASIS?
When a DSG system is installed, it is like commissioning a 30-year power plant that will, if properly maintained, produce energy and other benefits during that entire period. Several studies look at snapshots of benefits and costs in a given year, which fails to answer the basic question of whether DSG is cost-effective over its lifetime. Levelization involves calculating the stream of benefits and costs over an extended period and discounting to a single present value. Such levelized estimates are routinely used by utilities in evaluating alternative and competing resource options. As such, levelization of the entire stream of benefits and costs is appropriate.

Recommendation: We recommend use of a levelized approach to estimating benefits and costs over the entire DSG life of 30 years.

Q11: WHAT DATA AND DATA SOURCES ARE USED?
As the number of solar valuation studies has increased, so has the frequency with which newer studies cite data provided in prior studies. There are two reasons behind this trend, cost and availability of data, which we discuss in detail below.

As with any modeling exercise, models are only as good as the data fed into them. The ability to precisely calculate the benefits of DSG often rests on the availability and granularity of utility operational and cost data. More granular data yields more reliable analysis about the impacts of DSG deployment and operation.

Calculating many of the benefit and cost categories requires that analysts address utility-specific or regional conditions that can vary significantly from utility to utility, even within the same state. In addition, the availability of the type of granular data needed

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[28] Mills and Wiser point out that consideration of inter-system sales of capacity or renewable energy credits could mitigate reductions in incremental solar value that could accompany high penetration rates. *See* A. Mills & R. Wiser, *An Evaluation of Solar Valuation Methods Used in Utility Planning and Procurement Processes* (Lawrence Berkeley National Laboratory), LBNL-5933E, at p. 23, December 2012, *available at* http://emp.lbl.gov/publications/evaluation-solar-valuation-methods-used-utility-planning-and-procurement-processes.

to accurately project location and time-specific benefits varies from one utility to the next. Much of the data needed to quantify the benefits of DSG resides with utilities.

Fortunately, additional data, such as energy market prices, is often publicly available, or can be released by the utility without proprietary concerns. In some limited cases, the utility may have proprietary, competitive, or other concerns with plant- or contract-specific information. And in some cases, the form and format of utility data may require adjustments.

These problems are not insurmountable. Utility general rate cases and regulatory filings with the Federal Energy Regulatory Commission ("FERC") are good sources for data relevant to utility peak demand and for the components of cost of service, including transmission costs, line loss factors, O&M costs, and costs of specific distribution upgrades or investments, among other cost categories. Additionally, the federal Energy Information Administration ("EIA") and various state agencies compile utility cost data that can be used as a reference to determine heat rates, the costs of O&M associated with various plants, and the overall capital cost of new construction of generating capacity.[29]

Recommendation: Require that utilities provide the following data sets, both current information and projected data for 30 years[30]:

1) The five or ten-year forward price of natural gas, the most likely fuel for marginal generation, along with longer-term projections in line with the life of the DSG.
2) Hourly load shapes, broken down by customer class to analyze the intra-class and inter-class impacts of NEM policy.
3) Hourly production profiles for NEM generators. The use of time-correlated solar data is important to correctly assess the match of solar output with system loads. In the case of solar PV, this could vary according to the orientation of the system. For example, while south-facing systems may have greater overall output, west or southwest facing systems may produce more overall value with fewer kWh because of peak production occurring later in the day than a south-facing system.
4) Line losses based on hourly load data, so that marginal avoided line losses due to DSG can be calculated.
5) Both the initial capital cost and the fixed and variable O&M costs for the utility's marginal generation unit.
6) Distribution planning costs that identify the capital and O&M cost (fixed and variable) of constructing and operating distribution upgrades that are necessary to meet load growth.
7) Hourly load data for individual distribution circuits, particularly those with current or expected higher than average penetrations of DSG, in order to capture the potential for avoiding or deferring circuit upgrades.

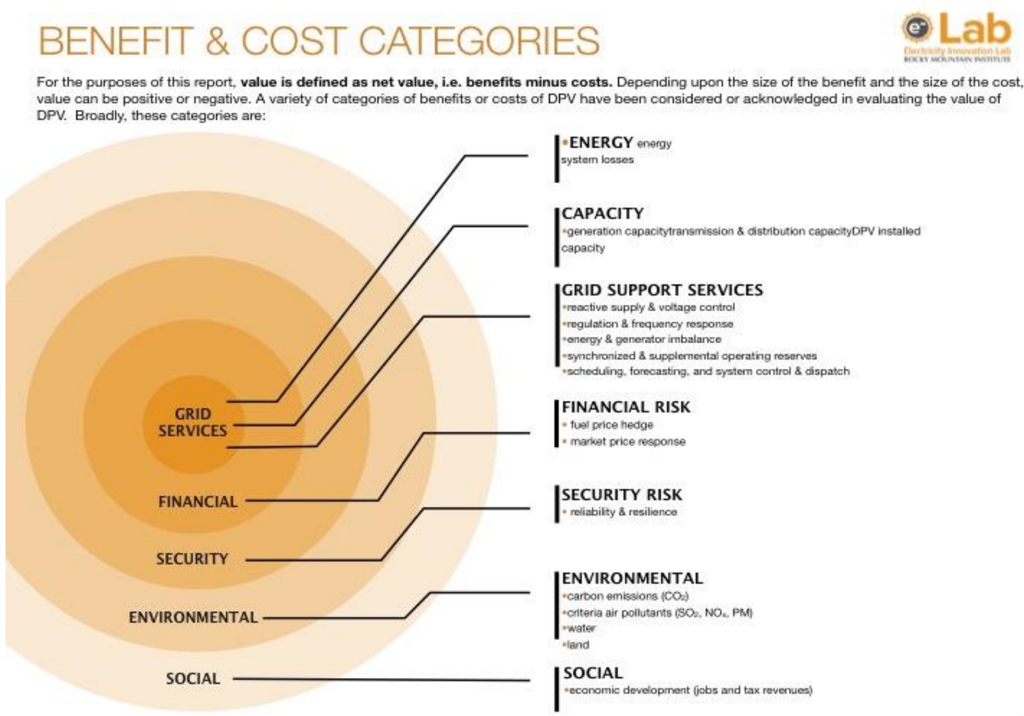
[29] *See Updated Capital Cost Estimates for Electricity Generation Plants* (EIA), November 2012, *available at* http://www.eia.gov/oiaf/beck_plantcosts/pdf/updatedplantcosts.pdf (providing estimate of capital cost, fixed O&M, and variable O&M for generation plants with various technical characteristics).

[30] Note: Where a utility or jurisdiction does not regularly collect some portion of this data, there may be methods to estimate a reasonable value to assign to DSG.

IV. Recommendations for Calculating the Benefits of DSG

Benefits of DSG get categorized and ordered in various ways from study to study, typically based on the relative magnitude of the benefits. The RMI 2013 Study is structured around a list of "services," encompassing flows of benefits and costs to and from solar PV. That list is replicated here in an effort to coordinate with that study.[31] The RMI services categories are depicted in the graphic below.

Figure 3: Rocky Mountain Institute Summary of DSG Benefits



While replicating the RMI services categories, we have subdivided them in recognition that the divide between utility avoided costs and other societal benefits is not clear from the list above. For instance, utilities can avoid certain environmental compliance costs, which are direct utility avoided costs, while other environmental benefits inure to society more generally. As another example, reliability or resiliency is only a utility avoided cost to the extent that the utility was going to take some other measures to achieve the levels enabled by DSG. If DSG enables higher reliability than would have otherwise been achieved, that is undoubtedly a benefit, though it is most notably realized by utility customers when a storm event does not cause a major service interruption, which may occur once in a decade. As a further example, market price

[31] *See* RMI 2013 Study.

response benefits can be felt by the utility itself but will also extend to citizens who are customers of nearby utilities.

To track utility avoided costs and societal benefits separately, separate subsections are provided below, with the final three RMI environmental and social benefit categories covered after utility avoided costs. We note where some categories listed under utility avoided costs have societal benefits as well, and we separately create an environment category under utility avoided costs to capture utility avoided environmental compliance costs.

Calculating Utility Avoided Costs

1. *Avoided energy benefits*

To determine the value of avoided generation costs, the first step is to identify the marginal generation displaced. In most instances, the next marginal generator will be a natural gas-fired simple-cycle combustion turbine ("CT") or a more efficient CCGT. Avoiding the operation of that marginal generating facility to produce the next increment of electricity means that the solar generator allows the utility to avoid both variable O&M activities (i.e., those activities and expenses that vary with the volume of output of the CT or CCGT plant) and the fuel that would be consumed to produce that next unit at the time that the customer-generator allows the utility to avoid that operation.

To calculate the avoided generation cost over the life of the DSG system—assumed throughout this paper to be 30 years—the calculation must estimate the market price of energy throughout that time span. Given the limitations on the availability of data, including the future price of a historically volatile commodity like natural gas, many studies have used interpolation and extrapolation to estimate gas prices in the 30 year horizon by taking the readily attainable current market price for natural gas and referencing it against the most forward natural gas price available.

Additionally, the calculation of avoided generation costs over time must account for degradation in the marginal generation plant and adjust expected heat rates (i.e., the measure of efficiency by which a unit creates electricity by burning fuel for heat to power a turbine). Over time, the marginal generation plant will become less efficient and require incrementally more fuel to reach the same production levels. Production cost modeling enables the utility to cumulate value of avoided costs throughout the useful life of the solar generating system. However, due to built in constraints or other issues, such modeling can produce results that are illogical, as has been seen in Arizona (baseload coal generation displaced by DSG) and Colorado (high cost of frequent unit startups reducing energy benefits).

A standard approach to determining the value of avoided generation over the life of a DSG system is to develop: (1) an hourly market price shape for each month and (2) a forecast of annual average market prices into the future.[32] One way to forecast the annual market prices, with less reliance on forward market prices, is to project the rolled-in costs of the marginal generation unit, accounting for variable O&M and

[32] E3 Study, Appendix A at pp.10-11.

Comparison with PURPA Avoided Cost Calculations

Value of solar analysis literature is complemented by other studies and reports related to the issue. These include studies relating to avoided cost methodologies under the Public Utility Regulatory Policies Act of 1978 ("PURPA"), and those addressing utility resource planning evaluation of distributed resources.

Because both the cost-benefit and value-of-solar approaches start with avoided cost calculations, publications and processes used in conducting such calculations are informative in establishing the costs and benefits of DSG. State utility commissions and public utility regulators have approached PURPA valuation of avoided costs quite differently, and FERC has rarely constrained the approach selected. Rather than attempt to discern a consensus approach, a more fruitful approach is to consider what PURPA allows.

IREC recently published a paper to do this, cataloguing the kinds of DSG-related avoided cost calculations that could improve understanding of DSG value, and citing most of the utility avoided costs discussed in this paper.

See the full report:
http://www.irecusa.org/wp-content/uploads/2013/05/Unlocking-DG-Value.pdf

degradation of heat rate efficiency in future years. This method still relies on forecasts of natural gas prices in future years, but provides more certainty for variable O&M costs.[33]

In the Vermont study, the Public Service Department assumed that the New England Independent System Operator ("ISO-NE") wholesale market would provide the marginal generation price for energy displaced by solar generation. To account for the high correlation of solar PV with system peak, and therefore the offset of higher value generation, the Department created a hypothetical avoided cost for 2011 using real output data that was matched with actual hourly market data from the ISO-NE market.[34] This adjusted hourly market price was then scaled to future years by utilizing an energy price forecast, based on the forward market energy prices for the first five years and for the forward natural gas prices for years five to ten.[35] Prices for years after year ten were based on an extrapolation of the market prices for electricity and natural gas for years one through ten.

As CPR observes, there are inherent shortcomings in relying on future market prices for marginal generation decades into the future.[36] A more straightforward method would be to "explicitly specify the marginal generator and then to calculate the cost of the generation from this unit."[37] In this way the avoided fuel and O&M cost savings are roughly equivalent to capturing the future wholesale price. Of course, this approach still relies on forward projections in the natural gas market.

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[33] CPR 2012 MSEIA Study at pp. 28-29.
[34] Vermont Study at p. 16.
[35] *Id.*
[36] CPR 2012 MSEIA Study at pp. 28-29.
[37] *Id.* at p. 29.

2. *Calculating system losses*

DSG sited at or near load avoids the inefficiencies associated with delivering power over great distances to the end-use customer due to electric resistance and conversion losses. When a DSG customer does not consume all output as it is being produced, the excess is exported to the grid and consumed by neighboring customers on the same circuit, with minimal losses in comparison to electricity generated by and delivered from a utility's centralized but distant plant. Without DSG and its local load reduction impact, utilities are forced to generate additional electricity to compensate for line losses, decreasing the economic efficiency of each unit of electricity that is delivered.

Including avoided line losses as a benefit is relatively straightforward and should be non-controversial. For instance, FERC's regulations implementing PURPA recognize that distributed generation can account for avoided line losses.[38] This benefit exists for all types of DG technologies and, to some extent, in all locations. Typically, average line losses are in the range of 7%, and higher during heavier load periods, which can correlate with high irradiance periods for many utilities.[39] Additional losses termed "lost and unaccounted for energy" are also likely associated with T&D functions and, with further research, may also be avoided by DSG.[40]

Average line loss is often used as the primary approach to adjusting energy and capacity-related benefits. However, because line losses are not uniform across the year or day, the use of average losses ignores significant value because it fails to quantify the "true reduction in losses on a marginal basis."[41] Considering losses on a marginal basis is more accurate and should be standard practice as it reflects the likely correlation of solar PV to heavy loading periods where congestion and transformer thermal conditions tend to exacerbate losses. In its Austin Energy study, CPR evaluated marginal T&D losses at times of seasonable peak demand using load flow analysis. CPR decided to average the marginal energy losses on the distribution system, for purposes of the study, and added marginal transmission losses in order to report hourly marginal loss savings due to solar generation. According to one APS study, the degree of line losses may decrease as penetration increases.[42]

As with the effect of reducing market prices by reducing load at times of peak demand, and therefore reducing marginal wholesale prices (see below), DSG-induced reduction of losses at times of peak load has a spillover effect. The ability of customers to serve on-site load without use of the distribution system reduces transformer

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[38] *See* FERC Order No. 69, 45 Fed. Reg. 12214 at 12227.("If the load served by the [QF] is closer to the [QF] than it is to the utility, it is possible that there may be net savings resulting from reduced line losses. In such cases, the rates should be adjusted upwards.").

[39] For example, the E3 study assumes an average loss factor of 1.073, which indicates that 7.3% more energy is supplied to the grid than is ultimately delivered and metered by the end-use customers. In contrast, Vermont's study noted that the Department's energy efficiency screening tool concluded that typical marginal line losses are about 9%. Vermont Study at p.17.

[40] *See*, *e.g.*, A. Lovins *et al.*, Small Is Profitable: The Hidden Economic Benefits of Making Electrical Resources the Right Size, Rocky Mountain Institute, at p. 212, August 2002; U.S. Energy Information Administration's Annual Energy Review, *available at* http://www.eia.gov/totalenergy/data/annual/diagram5.cfm.

[41] CPR 2012 MSEIA Study at p. 27.

[42] *Distributed Renewable Energy Operating Impacts and Valuation Study, R. W. Beck for Arizona Public Service, Jan. 2009, at p. 4-7 and Table 4-3. (Finding that a "law of diminishing returns" applies to solar distributed energy installations.) Available at: http://www.solarfuturearizona.com /SolarDEStudy.pdf.*

overheating, a major driver of transformer wear and tear, and in turn allows customers to receive power from utility generators at lower marginal loss rates. Without on- or near-peak DSG, all customers would face higher marginal loss rates with the contribution to thermal transformer conditions caused by all customers seeking grid delivered power for all on-site needs at times of peak load.

With consideration of the line losses avoided in relation to both the energy that did not have to be delivered due to DSG, and the marginal improvement in line losses to deliver power for the rest of utility's customers' needs, the appropriate methodology developed by CPR is to look at total line losses without DSG and total line losses with DSG. In practice this can equal 15-20% of the energy value.

Separately, line losses figure into capacity value as well, as a peak demand reduction of 100 MW means in turn that a generation capacity of more than 100 MW is avoided. This aspect of avoided line losses should be included with generation and T&D capacity benefits, discussed below.

3. *Calculating generation capacity*

Determining the capacity benefits of intermittent, renewable generation is a more complex undertaking than analyzing energy value, but there is a demonstrated capacity value for DSG systems. Capacity value of generation exists where a utility can count on generation to meet its peak demand and thereby avoid purchasing additional capacity to generate and deliver electricity to meet that peak demand.

While individual DSG systems (without energy storage) provide little firm capacity value to a utility given the potential for cloud cover, there is compelling research supporting the consideration of the aggregate value of DSG systems in determining capacity value. A recent study by LBNL demonstrates that geographic diversity tends to smooth the variability of solar generation output, making it more dependable as a capacity resource.[43] As well, FERC considered the fact that distributed solar and wind should produce some capacity value when considered in the aggregate when it was developing its avoided cost pricing regulations.[44] Capacity value for DSG systems should look to the characteristics of all DSG generators in the aggregate, including the smoothing benefits of geographic diversity.

Solving for Intermittency. CPR developed the most prominent and widely used method to address the intermittency of DSG technologies. This method recognizes a capacity value for intermittent, non-dispatchable resources, and is referred to the as the "effective load carrying capability" ("ELCC"). ELCC is a statistical measure of capacity that is "effectively" available to a utility to meet load. "The ELCC of a generating unit in a utility grid is defined as the load increase (MW) that the system can carry while

[43] *See* Andrew Mills and Ryan Wiser, *Implications of Wide-Area Geographic Diversity for Short-Term Variability of Solar Power* (Lawrence Berkeley National Laboratory), LBNL-3884E, September 2010.
[44] FERC Order No. 69, 45 Fed. Reg. 12214 at 12227 ("In some instances, the small amounts of capacity provided from [QFs] taken individually might not enable a purchasing utility to defer or avoid scheduled capacity additions. The aggregate capability of such purchases may, however, be sufficient to permit the deferral or avoidance of a capacity addition. Moreover, while an individual [QF] may not provide the equivalent of firm power to the electric utility, the diversity of these facilities may collectively comprise the equivalent of capacity.").

maintaining the designated reliability criteria (e.g., constant loss of load probability)."[45] In this way, ELCC provides a reliable statistical method to project the capacity value of intermittent resources.

On the other hand, the ELCC method can be data intensive and complex to some stakeholders. Simpler methods may also yield reasonable results. For example, an alternate method, based on the utility's load duration curve, looks at the solar capacity available for the highest load hours, usually the top 50 hours.

Implemented in a rate, a capacity credit for DSG denominated in kWh represents the best approach. This ensures that DSG only receives capacity credit for actual generation.

Valuing Small, Distributed Capacity Additions. An often controversial issue in determining avoided capacity value is the fact that distributed generation provides small, incremental additions and utility resource planning typically adds capacity in large, or "lumpy," blocks of capacity additions. For example, if a utility has ample capacity to meet its reserve margin and its next capacity addition will be a 500 MW CCGT, a utility might argue that incremental additions of 1 MW or 20 MW do not allow them to avoid capacity costs. FERC's regulations recognize that distributed generation provides a more flexible manner to meet growing capacity needs and can allow a utility to defer or avoid the "lumpy" capacity additions.[46] Therefore, it is inappropriate to hold that there is no capacity benefit for deployment of distributed generation in years that come before the time where the "lumpy" capacity investment is required. Distributed generation resources, like other demand-side resources that are continuously pursued to address load growth and to reduce peak demand, provide immediate benefit and a hedge against unexpected outages that could lead to a shortage in capacity. There is, therefore, no good reason to value DSG capacity for its long-term value only in years where it physically displaces the next marginal generating unit.

One solution around the valuation of incremental capacity additions versus lumpy additions that would follow more traditional utility planning is laid out in Crossborder Energy's 2013 update to the 2009 E3 Net Metering Cost-effectiveness study for California. In the E3 study, a mix of short-run and long-run avoided capacity costs are applied to renewable generators based on the fact that additional capacity would not be required until a certain year, called the "Resource Balance Year" in the E3 study. Crossborder's update recognizes the incremental value of small capacity additions for the years leading up to the Resource Balance Year and uses a long-run capacity value methodology for the life of the distributed generation system.[47] In other words, utilities are responsible for predicting load growth and planning accordingly, so the full penetration of DSG installations should already be built into their plans, reflecting the incremental capacity benefits these systems provide.

Adding It All Together: Determining the capacity credit for DSG systems. There are two basic approaches taken to determine capacity credit: (1) determine the market value

[45] CPR 2012 MSEIA Study at pp. 32-33.

[46] 18 C.F.R. 292.304(e)(2)(vii) (providing that avoided cost may value "the smaller increments and shorter lead times available with additions of capacity from qualifying facilities").

[47] Crossborder 2012 California Study, Appendix B.1.

of avoided capacity; or (2) estimate the marginal costs of operating the marginal generator, typically a CCGT.[48] For the same reasons that it is less than ideal to rely solely on the future projected market price for energy, it is also unreliable to credit DSG based on the projected future capacity market. The preferred approach is to determine the capacity credit by looking at the capital and O&M costs of the marginal generator.[49]

The resulting value is often termed a capacity credit—a credit for the utility capacity avoided by DSG. It is important to recognize that this credit is different from the "capacity value" of DSG. Capacity value is a term for the percentage of energy delivered as a fraction of what would be delivered if the DSG unit was always working at its rated capacity, that is, as if the sun were directly overhead with no clouds and the temperature was a constant 72 degrees at all times. Capacity value is typically in the range of 15-25% in the United States, depending on location. Because DSG generates electricity during daylight hours, often with high coincidence with peak demand periods, it earns a capacity credit based on the higher value of its generation during the hours in which it operates—a higher amount than simple capacity value. Alternatively, for a utility with an early evening peak or a winter peak, the capacity credit may be based on a lower percentage of its rated capacity than the capacity value.

Once the ELCC is determined for DSG resources for a given utility, the calculation of generation capacity is straightforward. The capacity credit for a DSG system is "the capital cost ($/MW) of the displaced unit times the effective capacity provided by PV."[50] Inherent in the ELCC calculation are the line losses associated with capacity, as discussed earlier.

4. <u>*Calculating transmission and distribution capacity*</u>

Distributed solar generation, by its nature, is usually located in close proximity to load on the distribution system, which may help reduce congestion and wear and tear on T&D resources. These benefits can reduce, defer, or avoid operating expenses and capital investments. Tactical and strategic targeting of distributed solar resources could increase this value.

The ability of DSG systems to yield T&D benefits is location-specific and also depends on the extent to which system output correlates to cost-causing local load conditions, especially before and during peak load periods. Utilities undertake system resource planning (i.e., planning for upgrades or additions to T&D capacity) to meet peak load conditions, so the correlation of DSG output to peak load conditions is important to understand. On the distribution system, unlike the bulk transmission system, this is a more difficult undertaking because local cost-causing load conditions (i.e., the timing, duration, and ramping rates associated with peak load on a given circuit) will vary according to a number of factors. These factors include customer mix, weather conditions, system age and condition, and others. As a simple example, a circuit that carries predominantly single-family residential load is likely to rise relatively smoothly to a peak in early evening, when solar PV output is waning. A circuit primarily serving

[48] CPR 2012 MSEIA Study at p. 32.
[49] *Id.* at pp. 32-33.
[50] *Id.*

commercial customers in a downtown setting will typically peak in the early afternoon. All other things being equal, DSG systems on circuits primarily serving commercial customers are more likely to avoid distribution capacity costs.

It is also important to consider system-wide T&D impacts. Transmission lines, and to an extent, substations, serve enough of a cross-section of the customer base to peak at approximately the same time as the utility as a whole. DSG coincidence with system peak means that DSG, even located on residential circuits, contributes to reduced demand at the substation level and above. Based on interconnection procedures, DSG systems in the aggregate on a circuit do not produce enough to export power off of the circuit; they simply reduce the need for service to the circuit. The avoided need for transmission infrastructure creates an avoided cost value to a utility and should be reflected as a benefit for DSG systems. Combining any granular distribution value with avoided, peak-related transmission costs, all DSG may demonstrate significant T&D value in allowing the utility to defer upgrades or avoid capital investments.

Estimating T&D Capacity Value. To determine the ability of DSG systems to defer T&D upgrades or capacity additions, it is critical to have current information on the system planning activities of utilities, and to periodically update that information. Often, the cost information is obtainable through rate case proceedings, where the utility ultimately seeks to include the upgrade or capital project in rate base. To make use of any cost data, however, it is important to have a sufficient amount of hourly data on both load and solar resource profiles. Much of the relevant information is also contained in utility maintenance cost data, grid upgrade and replacement plans, and capital investment plans. Beyond the planning horizon, expense and investment trends must be extrapolated to match the expected useful generating life of DSG.

With the data in hand, T&D capacity savings potential can be determined in a two-step process.[51] As described by CPR, "The first step is to perform an economic screening of all areas to determine the expansion plan costs and load growth rates for each planning area. The second step is to perform a technical load-matching analysis for the most promising locations."

For solar PV profiles, output can be estimated at particular places using irradiance data and various methods of estimating the output profile.[52] By looking at the load profile for a year, it is possible to isolate peak days at the circuit or substation level and calculate a capacity credit by measuring the net load with solar PV production. By reducing absolute peak load, DSG systems may allow a utility to avoid overloading transformers, substations or other distribution system components and, thereby, to defer expensive capital upgrades.

To determine deferral value, it is necessary to monetize the length of time that DSG allows a utility to defer a capital upgrade. Deferring an upgrade allows a utility to avoid the carrying cost or the cost of ownership of an asset and defers substantial expenditures that may be, at least to some extent, debt financed. Generally, the

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[51] *Id.* at p. 33 (citing T. E. Hoff, *Identifying Distributed Generation and Demand Side Management Investment Opportunities*, Energy Journal: 17(4), 1996).

[52] M. Ralph, A. Ellis, D. Borneo, G. Corey, and S. Baldwin, *Transmission and Distribution Deferment Using PV and Energy Storage*, published in Photovoltaic Specialists Conference (PVSC), 2011 37th IEEE, June 2011, *available at* http://energy.sandia.gov/wp/wp-content/gallery/uploads/TransandDistDeferment.pdf.

avoided capital is multiplied by the utility's weighted average cost of capital or authorized rate of return to determine the value of deferring that investment.[53] However, as noted earlier, a lower discount rate could be used. For instance, the avoidance of a million dollar transmission upgrade five years from now—for a utility with a 7% discount rate—is arguably worth that amount divided by (1.07)^5, or approximately $713,000. From the ratepayers' perspective, avoiding the million dollar upgrade in five years might be worth more; based on an estimated inflation rate of 3%, the value would be $862,000.

System-Wide Marginal Transmission and Distribution Costs. When conducting a statewide or utility-wide analysis, it may be difficult to hone in on specific locations to determine the ability of DSG systems to enable deferment or avoidance of system upgrade activity. In some cases, distribution deferral value manifests in changes in distribution load projection profiles and should be calculated as the difference in what would have happened without the DSG. E3's approach to valuing avoided T&D takes a broader look at the ability to avoid costs and estimates T&D avoided costs in a similar manner to other demand-side programs, such as energy efficiency. E3's avoided cost methodology develops "allocators" to assign capacity value to specific hours in the year and then allocates estimates of marginal T&D costs to hours. E3 acknowledges that it lacks sufficient data to base its allocators on local loads and that, ideally, "T&D allocators would be based upon local loads, and T&D costs would be allocated to the hours with the highest loads."[54]

E3 determined that temperature data, which is available in a more granular form for specific locations in the many climate zones of California's major utilities, would be a suitable proxy method for allocating T&D costs. After determining these allocators and assigning them to specific hours, E3 determined the marginal distribution costs by climate zone, using a load-weighted average. Since marginal transmission costs are specific to each utility, those are added to the marginal distribution costs to arrive at the overall marginal T&D for a specific climate zone. This approach lacks the potential for capturing high-value, location-specific deferral potential, but it does approximate some value without requiring extensive project planning cost and load data for specific feeders, circuits, and substations. E3's methodology may be suitable in circumstances where there is limited local load data to develop what E3 described as an "ideal" methodology, but it does come with drawbacks. For example, allocating costs to certain hours by temperature may not correlate to peak conditions in certain locations.

Alternative Approaches to T&D Valuation. Clean Power Research also approached T&D value broadly in its study of Pennsylvania and New Jersey, taking utility-wide average loads in a conservative approach to valuation. CPR's Pennsylvania and New Jersey report notes that T&D value may vary widely from one feeder to another and that "it would be advisable to . . . systematically identify the highest value areas."[55]

Where information on specific upgrade projects is known, and there is sufficiently detailed local load data, a more detailed analysis of deferral potential should yield far more accurate results that better reflect the T&D value of DSG. For example, CPR was

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[53] *Id.*
[54] E3 Study, Appendix A at p. 16.
[55] CPR 2012 MSEIA Study at p. 20.

ablle to take a more granular and area-specific look at T&D deferral values of DSG in its Austin Energy study, where it had specific distribution system costs for discrete sections of the city's distribution system.[56]

In Vermont, the Public Service Department took a reliability-focused approach. Noting that T&D upgrades are driven by reliability concerns, the Department determined that the "critical value is how much generation the grid can rely on seeing at peak times." To capture this benefit, the Department calculated a "reliability" peak coincidence value by calculating the average generator performance of illustrative generators for June, July and August afternoons.[57] The resulting number reflects the percentage of a system's nameplate capacity that is assumed to be available coincident with peak, as if it is "always running or perfectly dispatchable."[58] Accordingly, the generation system receives the same treatment as firm capacity in terms of value for providing T&D upgrade deferrals at that coincident level of output.

The risk of the Vermont approach is that it may overstate the ability of certain generators to provide actual deferral of T&D upgrades, since system planners often require absolute assurance that they could meet load in the event that a particular distributed generation unit went down. Another apparent weakness of this approach is the inability to target or identify location-specific values in the dynamic, granular nature of the distribution system.

T&D Capacity Value Summary. Distributed solar systems provide energy at or near the point of energy consumption. When they are generating, the loads they serve are therefore are less dependent on T&D services than other loads. In addition, because DSG provides energy in coincidence with a key driver of consumption—solar insolation—these resources can reduce wear and tear. Calculating the T&D benefits of DSG requires data that allows estimation of marginal T&D energy and capacity related costs. Ideally, utilities will collect location-specific data that can support individualized assessment of DSG system value. In the absence of such data, system-wide estimations of T&D offset and deferral value can be used with reasonable confidence.

5. *Calculating grid support (ancillary) services*

Grid support services, also referred to as ancillary services in many studies, include VAR support, and voltage ride-through. Existing studies often include estimates of ancillary services benefits as well as costs associated with DSG, as reported in the RMI 2013 Study. Costs, also called grid integration costs, are discussed below.

Currently, DSG systems utilize inverters to change direct current to alternating current with output at a set voltage and without VAR output, and with the presumed functionality of disconnecting in the event of circuit voltage above or below set limits. This disconnection feature has become a concern, as a voltage dip with the loss of a major utility generator could lead to thousands of inverters disconnecting DSG systems, reducing voltage inputs and exacerbating the problem. In practice, inverters could be

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[57] Vermont Study at p. 19 (The Department looked at ten two-axis tracking solar PV systems, four fixed solar PV systems, and two small wind generators.).
[58] *Id.* at p. 19.

much more functional or "smart"; indeed Germany is in the process of changing out hundreds of thousands of inverters to achieve added functionality.

Because U.S. electrical codes generally preclude inverters that provide ancillary services, many valuation studies have concluded that no ancillary service value should be calculated. While that approach had some merit in the past, when more versatile inverters where generally unavailable and regulatory change seemed far off, the present circumstances warrant a near-term recognition of ancillary services value. With proof of the viability of advanced inverters, it is highly likely that advanced inverters will be standard in the next few years, and ancillary services will be provided by DSG.

A group of Western utilities and transmission planners recently issued a joint letter on the issue of advanced inverters, calling for the deployment as soon as feasible to avoid the sort of cascading problem described above, which could lead to system-wide blackouts.[59] With the utilities themselves calling for advanced inverter deployment, and costs expected to be only $150 more than current inverters, there will be good reason to collect the data and develop the techniques to quantify ancillary services benefits of DSG. Modeling these ancillary services is important to inform policy decisions such as whether to require such technology as a condition of interconnection, and under what circumstances.

6. *Calculating financial services: fuel price hedge*[60]

DSG provides a fuel cost price hedge benefit by reducing reliance on fuel sources that are susceptible to shortages and market price volatility. In addition DSG provides a hedge against uncertainty regarding future regulation of greenhouse gas and other emissions, which also impact fuel prices. DSG customer exports help hedge against these price increases by reducing the volatility risk associated with base fuel prices—effectively blending price stability into the total utility portfolio.

The ideal method to capture the risk premium of natural gas uncertainty is to consider the difference between an investment with "substantial fuel price uncertainty" and one where the uncertainty or risk has been removed, such as through a hypothetical 30-year fixed price gas contract. As CPR explains, a utility could quantitatively set aside the entire fuel cost obligation up front, investing the dollars into a risk free instrument while entering into natural gas futures contracts for future gas needs.[61] Performing this calculation for each year that DSG operates isolates the risk premium and provides the value of the price hedge of avoiding purchases involving that risk premium.

Interestingly, utilities often used to hedge against fuel price volatility, but do less such hedging now. That leads some utilities to conclude that since the fuel price hedge benefit is not avoiding a utility cost, it should not be included. In practice, the risk of fuel price volatility is falling on customers even if the utility is not mitigating the risk. Reducing that risk has value to utility customers, even if the utility would not otherwise protect against it.

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[59] *See* L. Vestal, *Utility Brass Call for Smart-Inverter Requirement on Solar Installations*, California Energy Markets No. 1244, at p. 10, August 11, 2013.

[60] Clean Power Research now uses the term "Fuel Price Guarantee" in order to distinguish this benefit from traditional utility fuel price hedging actions.

[61] CPR 2012 MSEIA Study at p. 31.

7. *Calculating financial services: market price response*

Another portfolio benefit of DSG is measured in reductions to market prices for energy and capacity. By reducing demand during peak hours, when the price of electricity is at its highest, DSG reduces the overall load on utility systems and reduces the amount of energy and capacity purchased on the market. In this way, DSG reduces the cost of wholesale energy and capacity to all ratepayers.[62] This benefit is not captured by E3's methodology; it is reflected in CPR's most recent Pennsylvania and New Jersey study, where it is illustrated and explained in much greater detail.[63]

The premise of this benefit is that total expenditures on energy and capacity are less with DSG generation than without. The total expenditure, as CPR explains, is the current price of power times the current load at any given point in time. Because the amount of load affects the price of power, a reduced load condition, such as occurs as a result of DSG generation, reduces the market price of all other power purchases at those times.[64] While this change in market price is incrementally small, it represents a potentially significant system-wide benefit. This means that all customers, including non-solar customers, enjoy the benefit of lower prices during these reduced load conditions. As CPR notes, however, the reduction in price cannot be directly measured, as it is based on a hypothetical of what the price would have been without the load reduction, and must be modeled. The total value of market price reductions is the total cost savings calculated by summing the savings over all time periods during which DSG operates.[65] A similar analysis for capacity market prices can be conducted as well.

8. *Calculating security services: reliability and resiliency*

Particularly with the extended blackouts from Hurricane Sandy in 2012, a value is being attributed to added reliability and resiliency due to DSG, at both the grid and the individual customer levels. For grid benefits, this value in particular is difficult to quantify; it depends on the assumed risk of extended blackouts, the assumed cost to strengthen the grid to avoid that risk, and the assumed ability of DSG to strengthen the grid. With utility generation and T&D out of service, DSG can only do so much, and storm conditions often occur during periods of limited sunshine, so it is particularly hard to determine what DSG can do in this regard.

The ancillary services benefit discussed earlier is closely related to this benefit when considering the potential for the grid as a whole to continue operation. Even at the level of a circuit outage, the ancillary services benefit is capturing the value of providing VAR support and voltage ride-through. Arguably, the ancillary services benefit captures this level of grid support.

On the other hand, CPR noted in its first Austin Energy study that reliability and resiliency are very real DSG benefits at the individual customer level. The hospital with traditional backup generation powers up during an outage, and can be supported during a prolonged outage by the addition of DSG. Instead of relying entirely on the traditional generation and a substantial fuel supply, it can get by with less fuel. Likewise the

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[62] *Id.* at 15.
[63] *Id.* at pp. 33-43.
[64] CPR 2012 MSEIA Study at p. 34.
[65] *Id.* at p. 36.

residential customer with a medical condition requiring certainty can rely on DSG plus battery storage rather than a generator.

To the extent that utilities have an obligation to provided heightened reliability to vulnerable customers, DSG can be counted as avoiding those utility costs. On a larger scale, to the extent that customers enjoy greater reliability than the utility would otherwise provide, that is a benefit to participating customers that can be included.

9. *Calculating environmental services*

A. Utility avoided compliance costs. The cost of complying with regulatory and statutory environmental requirements is a real operating expense of a generating plant and should be included in the avoided cost of generation. This avoided cost typically is included in the studies as a direct utility cost. In the CPUC's 2010 CSI Impact Evaluation report, conducted by Itron, the CSI general market program and the Self-Generation Incentive Program ("SGIP") were estimated to be responsible for reducing over 400,000 tons of CO_2 emissions in 2010. Additionally, the report estimated that the CSI general market program and the SGIP provided over 52,000 pounds of PM_{10} and over 92,000 pounds of NOx emissions reductions in 2010.[66] These reductions can be quantified and calculated against the market price for the relative compliance instrument. To the extent these values are fully reflected in the cost of the avoided energy, they should not be counted again in a DSG valuation analysis. It is important to account for only residual environmental compliance costs in estimating the benefit of DSG.

While certain emissions credit markets will be geographically tied to a small area with no established compliance market, the markets for NOx, SOx, and CO_2 are more readily identified and quantified with publicly available sources. Accordingly, any study of DSG should include the value of avoided compliance costs reflected in air emissions, land use, and any consumption and discharge costs associated with water.

Likewise, utilities in states with Renewable Portfolio Standards ("RPS") avoid RPS compliance costs due to DSG. For example, if a utility must comply with a 20% RPS and has a billion megawatt hours ("MWh") of annual load, it has to secure 200 million MWh of renewable generation. If instead, 100 million MWh is generated by DSG facilities, the utility's annual load is reduced by that amount and its RPS compliance obligation is reduced by 20 million MWh. The utility's cost of procuring those 20 million MWh should be considered, to the extent that the procurement is greater than the utility's avoided natural gas energy and capacity costs already attributed to those 20 million MWh.

Quantification of societal benefits is particularly difficult and controversial. Regarding environmental benefits, avoided utility compliance costs capture what society has decided are the proper tradeoffs of electricity generation for pollution, but society recognizes additional value related to not generating electricity from fossil generation in the first place. If DSG within a given utility service territory avoids a 100 million MWh of gas-fired generation, the utility avoids paying for the required clean up the emissions

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[66] *California Solar Initiative 2010 Impact Evaluation* (California Public Utilities Commission), prepared by Itron, at p. ES-2, 2011, *available at* http://www.cpuc.ca.gov/NR/rdonlyres/E2E189A8-5494-45A1-ACF2-5F48D36A9CA7/0/CSI_2010_Impact_Eval_RevisedFinal.pdf.

that never occurred. However, had the utility generated those 100 million MWh, millions of pounds of pollutants would have gotten past the required emissions controls, and not emitting all of those pollutants is a significant benefit to the society.

While most utility avoided costs benefit the utility's ratepayers directly, societal benefits tend to be spread beyond the utility's customers. Job creation can be expected to center in the utility's service territory, but will also lead to jobs in adjoining service territories. Emissions benefits are even more dispersed. The benefits are regional or global, with utility generation often far removed from utility customers. This is the traditional "tragedy of the commons[67]" problem, but on a global scale. As with the problem of colonial farmers not having an incentive to care for the commons on which their cows grazed, utilities use the environment but have no incentive to care for it beyond what is legally required. By recognizing the value of not emitting pollutants in a DSG valuation study, analysts capture this value that utilities would otherwise ignore. To say that this benefit is realized by society, but somehow not by utility customers, is to ignore the reality that society is made up of utility customers.

Again, we use the benefits categories outlined in the RMI 2013 Study, of which the last three address societal benefits and are listed here.

B. Carbon. The RMI 2013 Study breaks out carbon as a separate avoided cost, based on the significant uncertainty of carbon regulation. On the one hand, carbon markets and restrictions on carbon emissions have been frequently discussed, and tied to climate change. On the other hand, almost no carbon restrictions are currently in place, despite all of the discussion. Studies now five years old that presumed carbon costs by 2013 have been proven wrong. However, with the establishment of a carbon market in California, and the continuation of carbon markets in Europe, the likelihood of carbon costs throughout the U.S. is well beyond zero.

Even in the absence of a carbon market or carbon restrictions, the benefits of not emitting carbon are considered to be real by many people. While some have touted the benefits of carbon for plant life, the widespread view appears to be that emitting more carbon has a negative impact. One way to approach this is to consider what customers are willing to pay for reduced emissions of both carbon and other matter. For instance, Austin Energy uses the premium value for their GreenChoice® green power product in the absence of compliance cost information in its Value of Solar rate.

Another carbon valuation option is to use the added utility cost to comply with RPS targets. The argument for this approach is that if society has determined that a 20% RPS is appropriate, and renewable energy costs an extra $10 per MWH to procure, then it would presumably value additional avoided emissions (both carbon and other matter) at the same rate. However, RPS systems are compliance systems that integrate price impact controls, credit trading schemes, and other features that impact compliance certificate prices without direct relationship to the value of associated emissions reductions. Caution should be used in applying a regulatory system designed to minimize the cost of compliance with an effort to accurately value benefits net of costs.

[67] G. Hardin, "The Tragedy of the Commons," Science 13 December 1968: 1243-1248. Available at: http://www.sciencemag.org/content/162/3859/1243.full?sid=f031fb58-2f56-4c25-ac0e-d802771c92ef

Where a state has a RPS mandate for its utilities, DSG provides a dual benefit. First, it lowers the number of retail sales that comprise the compliance baseline. Second, it results in the export of 100% renewable generation to the grid to offset some mix of renewable and fossil-fuel generation being produced to meet customer load.[68] The first benefit was discussed above, under avoided utility compliance costs. The second benefit accounts for the fact that energy exports from DSG are 100% renewable generation and arguably should be valued at 100% of the RPS value for purposes of a cost-benefit study.[69]

Another way to look at this is to say that all exports from a DSG system should receive the value of a market-priced renewable energy certificate, even where such a generator cannot easily create a tradable certificate.[70] This is justified because DSG exports help meet other customers' load on the utility's grid with 100% renewable energy and displace grid delivered electricity, which is only partially renewable. If a state has an RPS of 33% renewables, as does California, then DSG exports give rise to at least a 67% improvement in the renewable component of electricity.[71]

C. Airborne Emissions Other than Carbon and Health Benefits. Exceeding utility compliance with air regulations can be taken into account in a manner akin to that described for valuation of avoided carbon emissions. The public health impacts of fossil fuel generation have been well documented, though not well reflected in electricity pricing. In particular, air pollution can increase the severity of asthma attacks and other respiratory illnesses in vulnerable populations living in close proximity to fossil fuel-fired plants. Impacts on crops and forest lands have also been documented.

DSG reduces fossil fuel generation, especially from less efficient peaker plants and potentially from thermal plants that emit higher levels of pollution during startup operations. We are not aware of a dominant methodology, but note that public health literature will continue to grow in the area of recognizing and quantifying the public health impacts of electric generation, including health impacts related to climate change. Valuing emissions of carbon and other matter based on green energy pricing programs or RPS compliance costs, as described earlier, is an effective way to capture this benefit. Even outside of states with such programs, the value of reduced emissions is not zero; the value ascribed by nearby states with programs could serve as a proxy.

D. Avoided Water Pollution and Conservation Benefits. The utility industry uses and consumes a substantial portion of the nation's freshwater supplies for thermoelectric generation.[72] The benefit of not using the water for fossil-fuel generation should be

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[68] A third benefit associated with reducing overall market costs for renewable energy certificates may also manifest with increased DSG penetration.
[69] Crossborder 2013 California Study at pp.18-21.
[70] For example, owners of California NEM systems rarely bother to establish RECs related to their output given required documentation, and the treatment of RECs from NEM systems in a lower value "bucket" than RECs from systems with in-state wholesale sales to utilities.
[71] Crossborder 2013 California Study at p. 18.
[72] *How It Works: Water for Energy* (Union of Concerned Scientists), July 2013, *available at* http://www.ucsusa.org/clean_energy/our-energy-choices/energy-and-water-use/water-energy-electricity-overview.html.

based on the value of the water to society, that is, the value of conserving water for other beneficial uses.

Valuing water is intrinsically difficult. The tangle of water rights laws among the states complicate the determination of water value. To the extent that utilities have specific contracts for delivery or withdrawal of water to serve particular plants, it is likely that those expenses are already captured as an operating expense of the plant, but those are often at historic, ultra-low rates. Where a plant uses potable water, the value should be based on what society is willing to pay for that water. Likewise, where a plant is using non-potable, reclaimed water for cooling purposes, the appropriate value might be the price that someone would pay for an alternate use, such as irrigation.

The value to society of conserving water, which is of growing importance in water constrained regions of the country, is not adequately captured by the contract price for water or in the retail price that one would pay for an alternate use. We are not aware of a dominant methodology for measuring the conservation value of water, but this value should be considered as utilities consume a tremendous amount of water each year and will be increasingly competing for finite water resources. Avoiding the increased risk associated with maintaining secure, reliable, and affordable supplies of water is a benefit that DSG, with its 30-year expected operating life, delivers to all customers of the utility system.

10. *Calculating social services: economic development*

Installation and construction associated with onsite generation facilities is inherently local in nature, as contractors or installers must be within reasonably close geographic proximity to economically install a system and be present for building inspections. Accordingly, the solar industry creates local jobs and generates revenue locally. Economic activity associated with the growing rooftop solar industry creates additional tax revenue at the state and local levels as installers purchase supplies, goods and other related services subject to state and local sales tax, and pay payroll taxes. Locally spent dollars displace those frequently sent out of state for fuel and other supplies.

Taking a conservative approach, CPR's Pennsylvania and New Jersey study focused solely on tax enhancement value, which derives from the jobs created by the PV industry in those states. CPR used representative job creation numbers from previous studies in Ontario and Germany that quantify the number of jobs created by installing a unit of solar PV. CPR used assumptions that construction of solar PV involves a higher concentration of locally traceable jobs than construction of a centralized CCGT plant and determined the net local benefit of a solar project on the economy.

There remains a legitimate regulatory policy question of whether economic development benefits should be considered in calculating the value of DSG for use in setting electricity rates, or avoided cost calculations, even though there is a long history of economic development factors influencing commercial rates and line-extension fees. In any event, the economic development and tax base benefits of DSG deployment and operation should be consider when evaluating the societal cost-effectiveness of the technology and policies to support it.

Checklist of Key Requirements for a Thorough Evaluation of DSG Benefits

☑ **Energy benefits should be based on the utility not running a CT or a CCGT.** It is highly unlikely that DSG will offset coal or nuclear generation. Some combination of intermediate and peaking natural gas generation, with widely accepted natural gas price forecasts, should establish the energy value.

☑ **Line losses should be based on marginal losses.** Losses are related to load and DSG lowers circuit loads, which in turn lowers losses for utility service to other customers. Average line losses do not capture all of the loss savings; any study needs to capture both the losses related to the energy not delivered to the customer and the reduced losses to serve customers who do not have DSG.

☑ **Generation capacity benefits should be evaluated from day one.** DSG should be credited for capacity based on its Effective Load Carrying Capacity ("ELCC") from the day it is installed. If the utility has adequate capacity already, it may not have taken into account DSG penetration in its planning and overbuilt other generation; the DSG units that are actually operating during utility peaks should be credited with capacity value rather than a plant that is never deployed.

☑ **T&D capacity benefits should be assessed.** If the utility has any transmission plans, then DSG is helping to defer a major expense and should be included. On distribution circuits, watch for a focus on circuits serving residential customers, which tend to peak in the early evening when solar energy is minimal. Circuits serving commercial customers tend to peak during the early afternoon on sunny days, and a capacity value should be recognized for them in the form of avoided or deferred investment costs.

☑ **Ancillary services should be evaluated.** Inverters that can provide grid support are being mass-produced, and utility CEOs in the United States are calling for their use; ancillary services will almost certainly be available in the near future. Modeling the costs and benefits of ancillary services can also inform policy decisions like those related to interconnection technology requirements. and provides a hedging benefit.

☑ **A fuel price hedge value should be included.** In the past, utilities regularly bought natural gas futures contracts or secured long-term contracts to avoid price volatility. The fact that this is rarely done now and the customer is bearing the price volatility risk does not diminish the fact that adding solar generation reduces the reliance on fuels and provides a hedging benefit.

☑ **A market price response should be included.** DSG reduces the utility's demand for energy and capacity from the marketplace, and reducing demand lowers market prices. That means that the utility can purchase for less, saving money.

☑ **Grid reliability and resiliency benefits should be assessed.** Blackouts cause widespread economic losses that can be avoided in some situations with DSG. As well, customers who need more reliable service than average can be served with a combination of DSG, storage and generation that is less expensive than the otherwise necessary standby generator.

☑ **The utility's avoided environmental compliance costs should be evaluated.** DSG leads to less utility generation, and lower emissions of NOx, SOx and particulates, lowering the utilities costs to capture those pollutants.

☑ **Societal benefits should be assessed.** DSG policies were implemented on the basis of environmental, health and economic benefits, and should not be ignored or not quantified.

V. Recommendations for Calculating the Costs of DSG

Distributed solar generation comes with a variety of costs. These include the costs for the purchase and installation of the DSG equipment, the costs associated with interconnecting DSG to the electric grid, the costs of incentives, the cost associated with administration and billing, and indirect costs associated with lost revenues and other system-wide impacts. As with cost of service regulation in general, the important principles of cost causation and cost allocation are critical in dealing with DSG costs as well.

DSG cost estimation depends on the perspective from which one seeks to examine policies. Some costs, depending on perspective, should not be treated as costs in a DSG valuation study at all. For example, the cost of a DSG system net of incentives and compensation that the individual solar customer ultimately bears—the net investment cost, does not impact other customers. Whether a customer pays $100,000 or $20,000 for a five kilowatt ("kW") DSG system, the avoided utility costs and the societal benefits are unchanged.

In general, solar valuation studies address costs in varying degrees according to the aim of the individual study. A convenient way to characterize solar costs is according to who bears them. Costs relevant to determining value or cost effectiveness can generally be grouped into three categories:

1. Customer Costs—Customer costs are costs incurred by or accruing to the customers who use DSG. These include purchase and installation costs, insurance costs, maintenance costs, and inverter replacement, all net of incentives or payments received.
2. Utility and Ratepayer Costs—Utility and ratepayer costs are costs incurred by the utility and ratepayers due to the operation of DSG systems in the utility grid. These include integration and ancillary services costs, billing and metering costs, administration costs, and rebate and incentive expenses. In NEM valuation studies, utility lost revenues are potentially a significant utility cost, under the assumption that there are no other mechanisms to adjust for these losses.[73]
3. Decline in Value for Incremental Solar Additions at High Market Penetration—A number of studies also identify modeled impacts associated with significant penetration of solar on the utility system. Most studies characterize low penetration as less than 5% of peak demand or total energy met by solar generation, and characterize high penetration as 10%-15% or more. These

[73] Lost revenues arise when market penetration of consumption-reducing measures like energy efficiency and distributed generation have sales impacts that exceed those forecasted in the last rate-setting procedure, and only last until the next rate-setting, when a true-up can occur. Between rate cases, trackers or other mechanisms to mitigate impacts of regulatory lag can also be installed. Valuation studies themselves do not dictate whether lost revenues occur or are recovered. This is a function of tariff design. In some jurisdictions, for example, stand-by charges are used to adjust for revenue losses under NEM. In others, Buy All-Sell All arrangements or Net Billing models are used.

impacts can be accounted for as a cost or as an adjustment to value credit for solar energy when long-term impacts are considered.

When evaluating the cost-effectiveness of NEM, most utilities have access to cost-of-service data that can measure energy-related impacts. As noted earlier, the most direct and obvious source of potential cost or benefit of NEM policy is the mechanism that sets NEM customers apart from general ratepayers—the ability to use electricity not consumed instantaneously (i.e., exported energy) against future purchases of electricity in the form of a kWh or monetary bill credit. The value that customers derive from these bill credits is solely assignable to NEM as a policy, as distinguished from changes in behind-the-meter consumption that could occur under PURPA, in the absence of NEM policy. Accordingly, it is only appropriate to examine the net value of exports, and not behind the meter consumption, as a cost to non-participating ratepayers. It is also appropriate to note that NEM export costs are likely different depending on the class of customer generating excess solar energy. The good news is that the easy starting point for calculating NEM export energy costs is the monthly sum of the bill credits appearing on the customer bill, already adjusted by customer class. These credit costs can then be netted against the value of avoided produced or purchased energy.

1. <u>Recommendations for calculating customer costs</u>

Most value of solar studies focus on utility, ratepayer, and society costs, but not private costs. Therefore, these studies do not address customer investments or expenses in DSG. On the other hand, these costs are part of the total cost effectiveness of solar and have been addressed in broader societal perspective studies or in evaluating cost effectiveness for a solar incentive program. NEM and VOST programs are not intended to be incentive programs, but rather to fairly compensate customers for DSG.

When customer costs are included for a broader societal test, a major challenge in evaluating forward-looking solar customer costs associated with a long-term policy relates to accurately predicting the market prices for solar systems and installation as well as maintenance costs.

Regarding customer O&M costs, NREL has estimated costs between 0.05 and 0.15 cents per kWh.[74] E3 estimates customer O&M costs at $20 per kW with an escalator of .02% per year, factors inverter replacement at $25 per kW, once every 10 years, and estimates insurance expenses at $20 per kW, escalating at .02% per year.[75] Together, these O&M costs are fractions of a cent when converted to kWh, in line with the NREL estimate.

As noted, customer costs are rarely relevant to DSG policy valuation studies. The relevant question when evaluating DSG programs is what the net effect is on other utility customers.

2. <u>Recommendations for calculating utility costs</u>

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[74] *Photovoltaics Value Analysis* (National Renewable Energy Laboratory), February 2008, *available at* http://www.nrel.gov/analysis/pdfs/42303.pdf.

[75] *Technical Potential for Local Distributed Photovoltaics in California: Preliminary Assessment* (Energy & Environmental Economics, Inc.), March 2012 ("E3 Technical Potential Study 2012"), *available at* http://www.cpuc.ca.gov/NR/rdonlyres/8A822C08-A56C-4674-A5D2-099E48B41160/0/LDPVPotentialReportMarch2012.pdf.

The most significant utility cost for NEM program valuation purposes is avoided revenue. A customer who used to pay $1000 per year to her utility and then installed a NEM system and cut her bills to only $200 per year is seen as costing the utility $800 of lost revenue. Again, to the extent that the customer could install the same system under PURPA and reduce her bill to $300 per year, the net cost of the NEM program would only be $100, representing the extra savings that she realized due to the NEM program. For a VOST program, the intent is to determine the value of the benefits and credit that amount to customers for all generation. In effect, the cost of the program is automatically equated to the benefits of the program, net of charges for consumption or network services.

The second largest utility or societal cost of DSG programs is the cost of incentives, though this cost is declining rapidly. Incentive costs are direct costs when the utility provides the funding from ratepayers, but are indirect when considering taxpayer-funded incentives. While incentive costs are real, they are primarily justified on market-stimulation bases, and scheduled to expire in a matter of years. Given that independent rationale for incentives, incentive costs are generally not included in DSG valuations. As the installed cost of DSG has declined, the need for incentives and rebates has diminished, with the California market reaching the end of its state incentive program almost entirely, and federal incentives slated to end in 2016.

Integration costs are the third most important utility cost for NEM programs, and the leading factor for value of solar studies addressing utility costs. Integration costs include the direct costs associated with administration of utility functions associated with distributed solar systems, rebates and incentives, and other administrative tasks. Direct costs can be addressed as a cost or as a decrement to the benefits of DSG, since these costs enable the benefits.

Reports of utility costs vary most significantly with the assumed solar penetration rate used in the study. Integration costs are variously labeled as "integration costs," "grid support expenses," or "benefits overhead." Estimates of these costs range from 0.1 to 1 cent per kWh in studies that attempt to account for increased variability in the overall generation mix and resulting increases in ancillary services costs starting from very low solar penetration rates. Solar integration costs for a 15% market penetration level were estimated at 2.2 to 2.3 cents per kWh by Perez and Hoff, based on an analysis that focuses on the need and cost of storage to complement solar intermittency in order to provide firm capacity.[76] Navigant and Sandia performed an assessment of high penetration of utility scale solar in 2011 and estimated integration costs associated with increasing production to account for solar variability at between 0.31 cents for low penetration and 0.82 cents for higher penetration of roughly one gigawatt of installed solar.[77]

In states like California, where utilities are prohibited from charging solar customers for interconnection costs or upgrades, interconnection costs may be a substantial source of costs directly assignable to a DSG program. Where this is the case, it is necessary to have real, disaggregated data that tracks the exact interconnection costs of DSG. In

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[76] CPR 2012 MSEIA Study at p. 47.

[77] *Large Scale PV Integration Study* (Navigant), July 2011, *available at* http://www.navigant.com/insights/library/energy/2011/large-scale-pv-integration-study/.

the E3 study, for example, utilities did not have sufficient detail on interconnection costs in 2009 to provide a clear or transparent picture on the extent of those costs, or whether the costs incurred were reasonable and not blended in with other upgrades that would have occurred without the solar generator's interconnection. Interconnection costs should, in theory, be clearly identifiable through utility-provided data. In analyzing the value of distributed solar, these costs should also be amortized against the useful life of the measures.

In states where customers are responsible for interconnection costs and upgrades, however, this would not be a cost assignable to DSG policy. As with other customer costs, this is not a cost borne by the utility and should not be factored into an evaluation of the impact of a DSG policy on other customers.

Experience and more sophisticated modeling will be required to understand the shape and ultimate level of the integration cost curve. While integration costs are likely low at low market penetration levels, they are also likely to increase with market penetration. But these increases may decline as solar systems become more widely dispersed and as utilities begin targeting deployment to high-value locations within the grid. In addition, increased deployment of other distributed technologies, such as electric vehicles, distributed storage, load control, and smart grid technologies will impact the costs associated with larger scale DSG deployment.

The billing and administration costs associated with DSG encompass the one-time setup expenses of processing and verifying applications and the ongoing expense of administering unique features of solar customer bills. In states with modest numbers of solar customers, it is not uncommon to manually adjust solar customer bills, with associated incremental costs. Depending on the utility's accounting practices and billing capabilities, solar-specific billings cost should be relatively easily segregated and allocated. In states with automated processes, the ongoing incremental costs of administering solar customer accounts should be, as was determined in the Vermont study, nearly zero.[78]

In some cases, utilities will incur costs directly associated with DSG that are not fairly assignable to DSG policy. For example, in Texas, renewable energy generators under one MW are classed as "microgenerators," subject to registration and reporting requirements under the state's renewable energy portfolio standard law.[79] To the extent that the utility acts as a program manager and aggregator of renewable energy certificates assigned by solar generators, these costs are not fairly assigned to NEM or other solar promotional program unless also offset by the value of the assigned certificates.

3. Recommendations for calculating decline in value for incremental solar additions at high market penetration

The incremental positive value of additional solar deployment within a particular utility service territory is anticipated to decline as solar penetration levels increase. There are two major drivers of these impacts, which are not technically costs, but actually

[78] Vermont Study at p. 15.
[79] *See* 16 Tex. Admin. Code 15, *available at* http://www.puc.texas.gov/agency/rulesnlaws/subrules/electric/25.173/25.173.pdf.

decrement adjustments that impact value of solar in the context of expanding markets and higher solar penetration.

These impacts address the value of additional deployments and not past installations, and not replacement installations. The two major drivers are the expected reduction in capacity credit for solar and reduced peak energy value as market penetration increases. Capacity credits for solar are typically higher than capacity factor due to good solar coincidence with peak demand periods. However, as more solar is added to a system, the difference between peak and non-peak demand dissipates. Without storage, solar has a limited ability to reduce a system peak that is essentially shifted forward into evening hours. As a result, the incremental capacity benefit of solar is reduced for incremental additions as penetration increases. This impact could reduce capacity credit by 20-40% as penetration rates approach 15%.[80]

To the extent that solar energy is generated at periods of high utility cost, it provides great value. As the penetration rate of solar increases, peak market prices are likely suppressed, reducing the value of incremental solar energy. E3 estimated the reduced energy value at 15% over ten years in a study for California.[81]

Much work is needed in measuring and modeling the impact of high penetrations of DSG to address exactly how much DSG creates high penetration impacts, and inserting this clarity in valuation and cost effectiveness studies. Most states receive less than 0.5% of peak energy from distributed solar generation, while most studies looking at high penetration model levels at 10-15%. As noted earlier, the most relevant costs to consider are those that will occur at more modest penetrations. For example, if capacity benefits decline significantly at higher penetrations, that does not justify finding low capacity benefits at early stages.

Other important issues to be addressed include the impacts of different assumptions regarding geographic region, system size, and long-term changes in energy demand. It is important to note that both the capacity credit and energy value deterioration could be mitigated through consideration of energy sales from areas of high solar penetration to areas of lower penetration. For example, utilities facing near term surplus capacity situations could incur short-term lost revenues that could be mitigated over the period that solar systems operate, creating the potential for net benefits over that longer term.

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[80] *See* LBNL Utility Solar Study 2012, *supra*, footnote 13.
[81] *See* E3 Technical Potential Study 2012, *supra*, footnote 74.

Checklist of Key Requirements for a Thorough Evaluation of DSG Costs

☑ **Is lost revenue or utility costs the basis of the study?** For NEM studies, lost revenue is the standard (what the DSG customer would have otherwise paid the utility). For other studies and even some NEM studies, the cost to serve the DSG customer is addressed instead, which should lead to an inquiry in particular regarding allocation of capacity costs.

☑ **Assumptions about administrative costs must reflect an industrywide move towards automation.** With higher penetration, costs per DSG customer tend to decline, so administrative costs should assume automation of processes.

☑ **Interconnection costs should not be included.** If the DSG customer pays for the interconnection, this should not be included as a cost to the utility. As well, the utility's interconnection costs should be compared to national averages to determine whether they are reasonable.

☑ **Integration costs should not be based on unrealistic future penetration levels.** Studies tend to find minimal grid upgrade requirements at DSG penetrations below a few percent. Looking ahead to what the grid might need to accommodate 50% penetration unnecessarily adds costs that are not actually being incurred.

VI. Conclusion

Valuations vary by utility, but valuation methodologies should not. In this report IREC and Rabago Consulting LCC suggests a standardized approach for calculating DSG benefits and costs that we hope proves helpful to regulators as they embark on commissioning or reviewing valuation studies. Please see the mini-guide at the end of this report for a quick reference guide to the recommendations in this report.

REGULATOR’S MINI-GUIDEBOOK

Calculating the Benefits and Costs of Distributed Solar Generation

Valuations vary by utility, but valuation methodologies should not. IREC and Rábago Energy LLC suggest a standardized approach for calculating DSG benefits and costs in the white paper “A REGULATOR’S GUIDEBOOK: Calculating the Benefits and Costs of Distributed Solar Generation.” We hope that this paper proves helpful to regulators as they embark on commissioning or reviewing valuation studies. Below is a high-level summary of the recommendations in the white paper. Please see the full report for more detail per section.

A. KEY QUESTIONS TO ASK AT THE ONSET OF A STUDY

Q1: WHAT DISCOUNT RATE WILL BE USED?

Recommendation: We recommend using a lower discount rate for DSG than a typical utility discount rate to account for differences in DSG economics.

Q2: WHAT IS BEING CONSIDERED – ALL GENERATION OR EXPORTS ONLY?

Recommendation: We recommend assessing only DSG exports to the grid.

Q3: OVER WHAT TIMEFRAME WILL THE STUDY EXAMINE THE BENEFITS AND COSTS OF DSG?

Recommendation: Expect DSG to last for thirty years, as that matches the life span of the technology given historical performance and product warranties. Interpolate between current market prices (or knowledge) and the most forward market price available or data that can accurately be estimated, just as planners do for fossil-fired generators that are expected to last for decades.

Q4: WHAT DOES UTILITY LOAD LOOK LIKE IN THE FUTURE?

Recommendation: Given that NEM resources are interconnected behind customer meters, and result in lower utility loads, the utility can plan for lower loads than it otherwise would have. In contrast, other DSG rate or program options involving sale of all output to the utility do not reduce utility loads, but rather the customer facilities contribute to the available capacity of utility resources.

Q5: WHAT LEVEL OF MARKET PENETRATION FOR DSG IS ASSUMED IN THE FUTURE?

Recommendation: The most important penetration level to consider for policy purposes is the next increment: what is likely to happen in the next three to five years. If a utility currently has 0.1% of its needs met by DSG, consideration of whether growth to 1% or even 5% is cost-effective is relevant, but consideration of whether higher penetrations are cost-effective can be considered at a future date.

Q6: WHAT MODELS ARE USED TO PROVIDE ANALYTICAL INPUTS?
Recommendation: Transparent input models that all stakeholders can access will establish a foundation for greater confidence in the results of the DSG studies. When needed, the use of non-disclosure agreements can be used to overcome data sharing sensitivities.

Q7: WHAT GEOGRAPHIC BOUNDARIES ARE ASSUMED IN THE ANALYSIS?
Recommendation: It is important to account for the range in local values that characterize the broader geographical area selected for the study. In some cases, quantification according to similar geographical sub-regions may be appropriate.

Q8: WHAT SYSTEM BOUNDARIES ARE ASSUMED?

Recommendation: It may also be appropriate to consider impacts associated with adjacent utility systems, especially at higher (above 10%) penetration levels of DSG. [82]

Q9: FROM WHOSE PERSPECTIVE ARE BENEFITS AND COSTS MEASURED?

Recommendation: We recommend that ratepayer and societal benefits and costs should be assessed.

Q10: ARE BENEFITS AND COSTS ESTIMATED ON AN ANNUALIZED OR LEVELIZED BASIS?

Recommendation: We recommend use of a levelized approach to estimating benefits and costs over the full assumed DSG life of 30 years. Levelization involves calculating the stream of benefits and costs over an extended period and discounting to a single present value. Such levelized estimates are routinely used by utilities in evaluating alternative and competing resource options.

B. DATA SETS NEEDED FROM UTILITIES

- ☑ The five or ten-year forward price of natural gas, the most likely fuel for marginal generation, along with longer-term projections in line with the life of the DSG
- ☑ Hourly load shapes, broken down by customer class to analyze the intra-class and inter-class impacts of NEM policy
- ☑ Hourly production profiles for NEM generators, including south-facing and west-facing arrays
- ☑ Line losses based on hourly load data, so that marginal avoided line losses due to DSG can be calculated
- ☑ Both the initial capital cost and the fixed and variable O&M costs for the utility's marginal generation unit

[82] Mills and Wiser point out that consideration of inter-system sales of capacity or renewable energy credits could mitigate reductions in incremental solar value that could accompany high penetration rates. *See* A. Mills & R. Wiser, *An Evaluation of Solar Valuation Methods Used in Utility Planning and Procurement Processes* (Lawrence Berkeley National Laboratory), LBNL-5933E, at p. 23, December 2012 (nt Processes energy credits could *available at* http://emp.lbl.gov/publications/evaluation-solar-valuation-methods-used-utility-planning-and-procurement-processes.

☑ Distribution planning costs that identify the capital and O&M cost (fixed and variable) of constructing and operating distribution upgrades that are necessary to meet load growth

☑ Hourly load data for individual distribution circuits, particularly those with current or expected higher than average penetrations of DSG, in order to capture the potential for avoiding or deferring circuit upgrades

Note: where a utility or jurisdiction does not regularly collect some portion of this data, there may be methods to estimate a reasonable value to assign to DSG.

C. RECOMMENDATIONS FOR ASSESSING BENEFITS

1. **The following benefits should be assessed:**
    1. Energy
    2. System Losses
    3. Generation Capacity
    4. Transmission and Distribution Capacity
    5. Grid Support Services
    6. Financial: Fuel Price Hedge
    7. Financial: Market Price Response
    8. Security: Reliability and Resiliency
    9. Environment: Carbon& Other Factors
    10. Social: Economic Development
2. **Energy benefits should be based on the utility not running a CT or a CCGT.** It is highly unlikely that DSG will offset coal or nuclear generation. Some combination of intermediate and peaking natural gas generation, with widely accepted natural gas price forecasts, should establish the energy value.
3. **Line losses should be based on marginal losses.** Losses are related to load and DSG lowers circuit loads, which in turn lowers losses for utility service to other customers. Average line losses do not capture all of the loss savings; any study needs to capture both the losses related to the energy not delivered to the customer and the reduced losses to serve customers who do not have DSG.
4. **Generation capacity benefits should be evaluated from day one.** DSG should be credited for capacity based on its Effective Load Carrying Capacity ("ELCC") from the day it is installed. If the utility has adequate capacity already, it may not have taken into account DSG penetration in its planning and overbuilt other generation; the DSG units that are actually operating during utility peaks should be credited with capacity value rather than a plant that is never deployed.
5. **T&D capacity benefits should be assessed.** If the utility has any transmission plans, then DSG is helping to defer a major expense and should be included. On distribution circuits, watch for a focus on circuits serving residential customers, which tend to peak in the early evening when solar energy is minimal. Circuits serving commercial customers tend to peak during the early afternoon on sunny days, and a capacity value should be recognized for them in the form of avoided or deferred investment costs.
6. **Ancillary services should be evaluated.** Inverters that can provide grid support are being mass-produced, and utility CEOs in the United States are calling for

their use; ancillary services will almost certainly be available in the near future. Modeling the benefits and costs of ancillary services can also inform policy decisions like those related to interconnection technology requirements.

7. **A fuel price hedge value should be included.** In the past, utilities regularly bought natural gas futures contracts or secured long-term contracts to avoid price volatility. The fact that this is rarely done now and that the customer is bearing the price volatility risk does not diminish the fact that adding solar generation reduces the reliance on fuels and provides a hedging benefit.

8. **A market price response should be included.** DSG reduces the utility's demand for energy and capacity from the marketplace, and reducing demand lowers market prices. That means that the utility can purchase these services for less, saving money.

9. **Grid reliability and resiliency benefits should be assessed.** Blackouts cause widespread economic losses that can be reduced or avoided in some situations with DSG. As well, customers who need more reliable service than average can be served with a combination of DSG, storage and generation that is less expensive than the otherwise necessary standby generator.

10. **The utility's avoided environmental compliance and residual environmental costs should be evaluated.** DSG leads to less utility generation, and lower emissions of NOx, SOx and particulates, lowering the utilities costs to capture or control those pollutants.

11. **Societal benefits should be assessed.** DSG policies were implemented on the basis of environmental, health and economic benefits, which should not be ignored and should be quantified.

D. RECOMMENDATIONS FOR ASSESSING COSTS

1. **Determine whether lost revenue or utility costs are the basis of the study.** For NEM studies, lost revenue is the standard (what the DSG customer would have otherwise paid the utility). For other studies and even some NEM studies, the cost to serve the DSG customer is addressed instead, which should lead to an inquiry in particular regarding allocation of capacity costs.

2. **Assumptions about administrative costs should reflect an industry-wide move towards automation.** With higher penetration, costs per DSG customer tend to decline, so administrative costs should assume automation of processes.

3. **Interconnection costs should not be included.** If the DSG customer pays for the interconnection, this should not be included as a cost to the utility. As well, the utility's interconnection costs should be compared to national averages to determine whether they are reasonable.

4. **Integration costs should not be based on unrealistic future penetration levels.** Studies tend to find minimal grid upgrade requirements at DSG penetrations below a few percent. Looking ahead to what the grid might need to accommodate 50% penetration unnecessarily adds costs that are not actually being incurred.

APPENDIX B: Task Report 3 Appendices

Appendix A:

Task 3 - Analysis of Costs and Benefits: Key Assumptions

Massachusetts Net Metering Task Force

PEREGRINE ENERGY GROUP

Sustainable Energy Advantage, LLC

MEISTER CONSULTANTS GROUP

La Capra Associates

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(2)

A. OVERARCHING ASSUMPTIONS & SIMPLIFYING ASSUMPTIONS

& SIMPLIFYING ASSUMPTIONS

(3)

Key Assumptions

- Analysis performed, and metrics, in Nominal $
- Tax Rates
  - Massachusetts Tax Rates = 8%
  - Federal Tax Rates = 35%
- Nominal Discount rate = 5%
- Federal Investment Tax Credits (ITC) were not assumed to be extended beyond their current statutory timeframe.
- General inflation rate from EIA AEO 2014 GDP IDP
- Inflation rate for ACP from EIA AEO 2014 CPI All Urban Customers

(4)

MA DG Solar Avoids Electric Losses

Raw Data (Utility-specific average & peak loss factors)

		Average T&D	Peak T&D	Avg. excl. TX losses	Peak excl. TX losses
Wtd. Avg MA		5.15%	8.62%	4.35%	7.34%
	weight				
NSTAR	45.28%	4.70%	6.60%	3.77%	5.300%
WMECO	7.79%	5.00%	9.78%	4.45%	8.70%
NGRID - MECO	45.69%	5.60%	10.38%	4.90%	9.077%
NGRID - NEC	0.31%	5.60%	10.38%	4.90%	9.08%
FG&E	0.92%	5.60%	10.38%	4.90%	9.08%

Blue: provided by EDCs
Black: imputed based on similar relationships of peak to average data in blue
Red: used other EDC data as proxies

For Solar Impact ➔ Statewide Factors

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

Production weighting reflects higher-than-average loss reduction due to peak coincidence
(developed using inferred square-function matching average and peak losses)

(5)

Key Considerations for Understanding Results:
Implications of Simplifying Assumptions (1)

1. **Retail Rate Structures Held Constant.** Assumed no change in retail rate structures from current, with respect to any shift from components billed on a per-kWh basis to fixed charges, customer charges, or the establishment of minimum bills. Task Force determined that rate design is important but best addressed before the DPU.
   - A future shift in rate structure away from kWh charges would reduce the avoided cost or revenue realized for behind-the-meter or net metered solar PV projects ➔ Would diminish economics, lead to a slower build-out and a potential shift among installation types unless solar incentives were increased to match (as might be the case under Paths A and B).
   - However, this analysis assumes that a subsector of the marketplace whose retail rate value is not hedged through fixed-price PPA or discount arrangements would derate expectations of future rate revenue to some degree to account for exposure to change of rate structure risk (i.e., host owned <= 25 kW systems under SREC or Path B)
2. **Distribution System Saturation Ignored.** Did not explicitly examine limitations on development caused by saturation of distribution feeders or resulting elevated interconnection costs. Considering such factors would slow the pace of development.(forecast of installations does consider interconnection timelines/constraints).
3. **Technical Potential Saturation Largely Ignored.** Did not explicitly constrain solar technical potential. However, modeling does consider land area, population density, number of residential customers and number of non-residential customers in regards to growth rates and relative potential among utilities. Paths A&B have low growth rates and are not likely to be constrained by technical potential, but are constrained by the policy mechanism itself. Path B is constrained economically. Separately, we have done research that did not find significant near term constraints on brownfield, landfills, or VNM low-moderate income housing sub-sectors.

(6)

Key Considerations for Understanding Results:
Implications of Simplifying Assumptions (2)

4. **Ignored Potential Differential Impacts of Installer Incentive Capture.** Did not explicitly assume or analyze installed cost inflation under the more 'generous' policy options (compared to less generous policies), an installer 'incentive capture' phenomenon cited by some analysts, or assume lower installed costs for Policy futures with less generous combined solar and NM incentives.

5. **Ignored Impact of ITC Qualification Peril at 1/1/17.** Did not reflect the likelihood that projects are unwilling to commit to projects with risk exposure to loss of ITC due to interconnection delay or labor shortages in 2016, which may in practice lead to a risk-aversion-driven drop-off in development. Simplified to assume a steadier rate of development influenced by economics and shifted some development back to earlier in the year as participants are well aware of the pending loss of ITC, the risk in being late and are starting development activity earlier.

6. **Assumed Municipal Light Plants Participate Like IOUs in Policy Paths A & B.** MLPs are assumed to participate in Policy Paths A&B the same way as do investor owned utilities (including allowing or not allowing virtual net metering in capped and uncapped scenarios). We treated all MLPs as having a single prototypical rate structure based on Taunton Municipal Lighting Plant rates.

7. **Assumed Future LSE Participation in SREC Floor Price Auctions.** LSEs will fully participate in auction and thus hold marginal SRECs during the auction out years. If LSEs continue to stay on sidelines, it causes extreme additional expenses for NPRs ➔ seems imprudent to assume that this practice would continue indefinitely.

(7)

Key Considerations for Understanding Results:
Implications of Simplifying Assumptions (3)

7. **Ignored Nantucket as a location for solar development.** Did not include Nantucket Electric in the primary analysis

8. **Reclassified SREC-I Projects into SREC-II Sectors.** In order to provide SREC-I results in a comparable manner to other policy paths, we have made best guesses of project reclassification to SREC-II subsectors. Assigning SREC-II subsectors provides a basis of computing and reporting build-out, revenue and cost and analysis.

9. **Treated All Towns as Served by Single Distribution Utility.** In order to assess potential for different project types, utility square miles were computed. Some Massachusetts towns are served by multiple utilities. We assigned each town a unique utility in order to simplify the calculation.

(8)

B. SOLAR PV MODELING

FOR DISPATCH ANALYSIS ANDS COST & BENEFIT ANALYSIS

(9)

Solar PV Production Modeling
Technical Assumptions (1)

- Analysis requires understanding:
  - How many MWh produced per DC MW PV installed?
    - # of SRECs (current policy) is less than this #
  - When production occurs?
    - Value of energy; Coincidence with applicable peaks
- 25-year economic Life of Solar PV Installations
- Key & Simplifying Assumptions:
  - Ignore technological advance and change in mix of fixed vs. tracking
    - Performance (profile and capacity factor) held constant for each installation type across analysis horizon and policy path
  - Degradation: 0.5% energy production per yr.
- AC vs. DC
  - PV rated @ Direct Current (DC)
  - Inverters convert to AC (Alternating Current)
  - Energy on the grid is AC
  - Solar Policy Goals are stated in DC
  - DC to AC conversion efficiency varies by installation type
- Annual Production:
  - Use "Proxy" profile representing simplified composite of different installation types
  - Installation composition may vary over time
  - PV Watts (NREL model estimating production @ specified location) used to estimate production volume and timing
  - PV Watts requires assumptions on tile, azimuth (degrees from due south), AC to DC ratio determinates, shading, etc.
  - MA CEC's Production Tracking System (PTS) provides performance details on current MA PV fleet
  - SEA studied PTS data on existing fleet, developed 'standard' installation characteristics for **composite project type**: Residential, C&I Rooftop, Ground Mount and Solar Canopy installations
  - SEA assumed fraction of each SREC-II subsector associated with each composite project type
  - For PV Watts, assumed single location (Worcester)
- Results: Year 1 for any installation for current SREC-II fleet
  - Capacity Factor (c.f.) (DC) = 14.3%
  - Annual energy: 1627 kWh per AC kW installed
  - Annual energy: 1253 kWh per DC kW installed

(10)

Solar PV Technical Assumptions
Application to Modeling of Solar Policy & Net Metering Impacts (2)

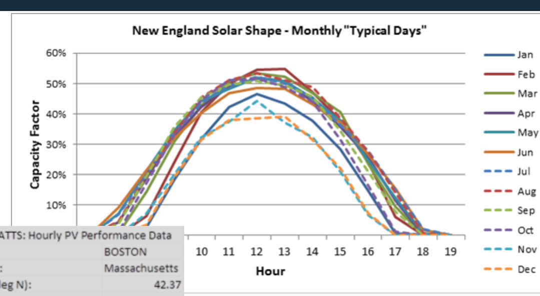
- Each SREC-II subsector has:
  - Composite proxy profile (constant c.f. and production profile over time)
  - Economics of each subsector vary under each policy path ➔ different quantity of PV installed for each subsector under each policy path
  - Policy-path-specific blend of composite profiles and installation proportions ➔ aggregate annual PV production in each year ➔ "Portfolio Annual Production"
    - c.f. was held constant over time and between policy paths as a simplification
- Area for potential future study:
  - Allow performance over time to vary with evolving blend of system types
  - More nuanced profile as weighted average of projects of varying technology, orientation, tilt, etc.
  - Consider technology advance
  - Would allow looking at possible benefits of encouraging more peak-value orientation, etc.

Residential System	Commercial Rooftop	Ground Mount	Solar Canopy
16%	18%	63%	3%

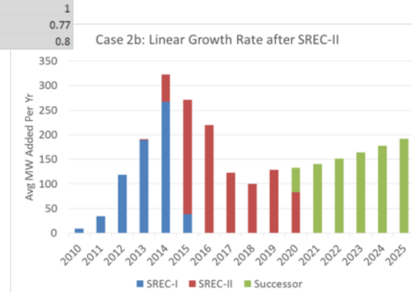
(11)

Solar PV Technical Assumptions
Application to Modeling - Production Modeling in Aurora (3)

- Applies to: market value, energy market price impacts, emission impacts
- Uses a single standard proxy profile of average day per month based on PV Watts profile, 0.77 AC/DC (Boston) (see graph and table: 14% annual c.f. (DC); 1593 kWh per AC kW
  - Same as DOER 2013 Task 3B report
- MW targets in DC
- Modeling convention: Policy paths have similar solar PV build-out quantities
  - Small differences will not alter per-MWh values materially
- Results of a single Aurora build-out analysis (graph) → scaled to *projected* portfolio annual production in each case using per-MWh Aurora result values

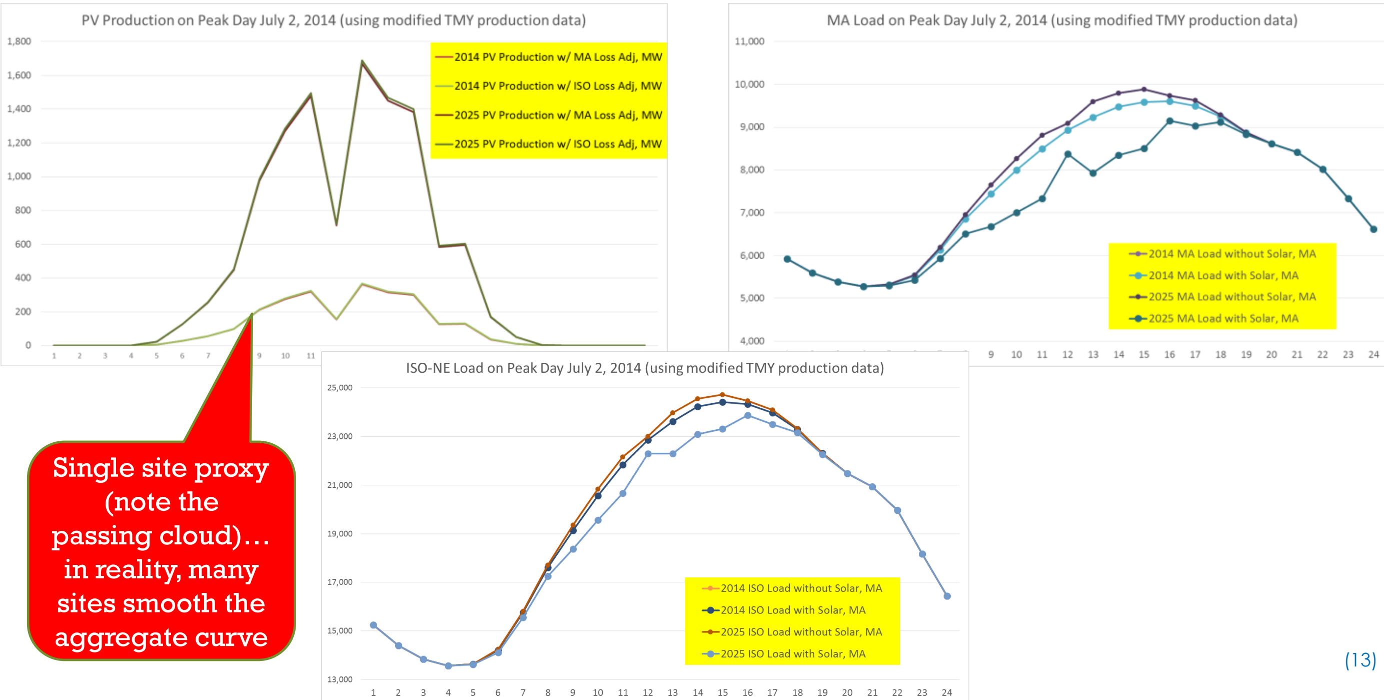


PVWATTS: Hourly PV Performance Data	
City:	BOSTON
State:	Massachusetts
Lat (deg N):	42.37
Long (deg W):	71.03
Elev (m):	5
Array Type:	"Fixed Tilt"
Array Tilt (deg):	42.4
Array Azimuth (deg):	180
DC Rating (kW):	1
DC to AC Derate Factor:	0.77
AC Rating (kW):	0.8



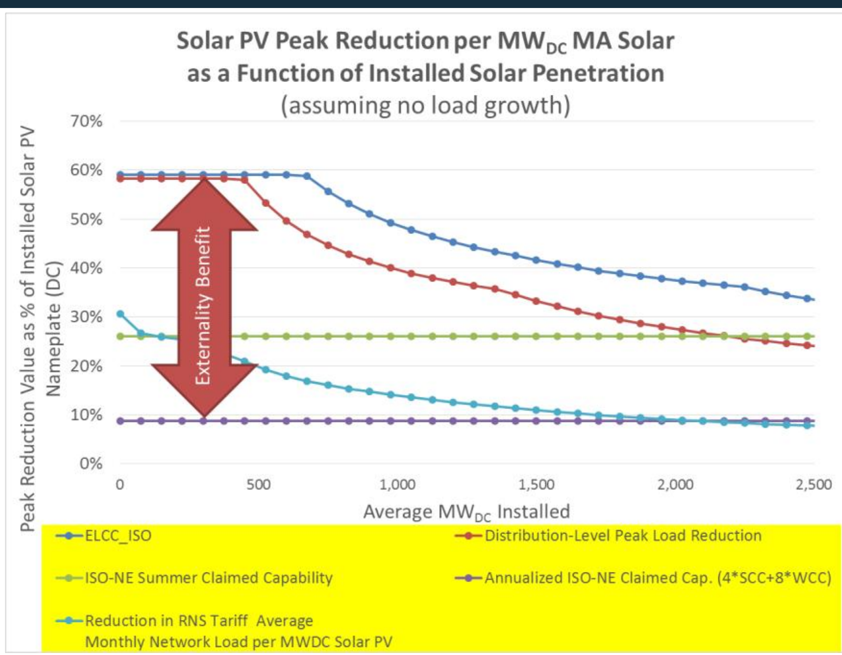
(12)

Solar Peak Impact



(13)

Solar PV Impact on Avoiding G, T & D Capacity



- ISO-NE FCM value (purple):
  - Doesn't vary with PV MW
  - Well below impact on reducing peaks until PV penetrations >> 2500 MW
- Actual PV impact on peaks declines with penetration
  - PV has high peak coincidence
  - But starting to shift time of peak
  - Eventually: the CA 'Duck Diagram'
- G&T peak reduction value (blue) somewhat higher than Distribution value due to different timing of peaks
- Difference between *actual* impact (e.g. lower ISO ICR) and value in FCM market is a *benefit* to all citizens of MA
- FCM value not monetized by generators also a *benefit* to all citizens of MA

(14)

C. WHOLESALE MARKETS & PRODUCTION DISPATCH MODELING ASSUMPTIONS

DISPATCH MODELING & COST/BENEFIT ASSUMPTIONS

(15)

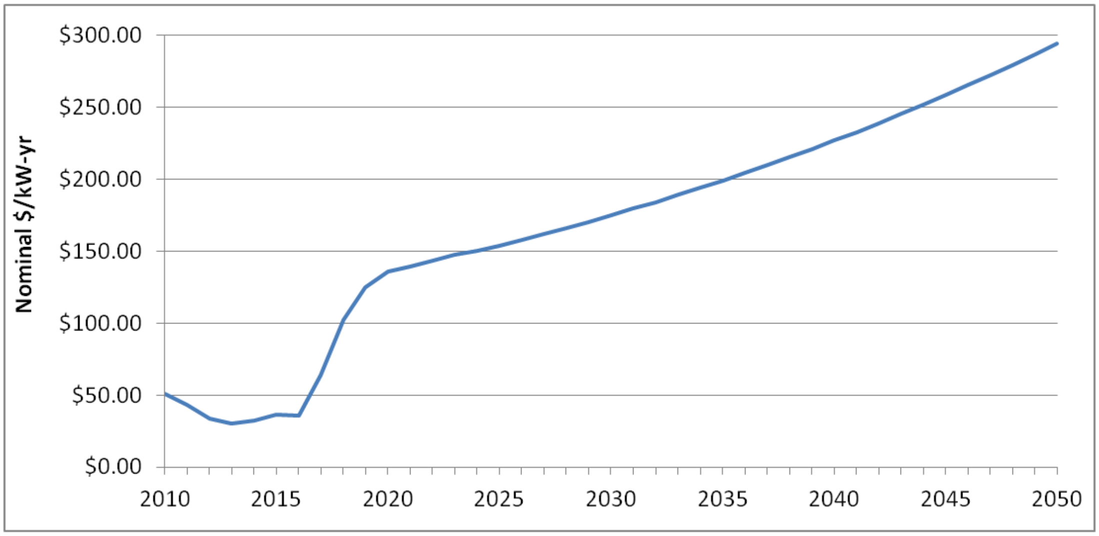
Wholesale Market Assumptions

- ISO-NE Transmission Tariff:
  - 2014 RNS Tariff Rate = $89.80/kW-yr
  - 2014 RNS MA Load Ratio Share = 43.59%
- Installed Capacity Reserve Margin
  - Per ME VOS study, for the year 2017/18, the ISO New England reserve margin was 13.6% based on Net ICR

(16)

Capacity Market Assumptions

- Capacity market prices = Historic actuals, projected values taken from CT 2014 IRP, adjusted to nominal using AEO 2014 GDP deflator, and converted to calendar year



(17)

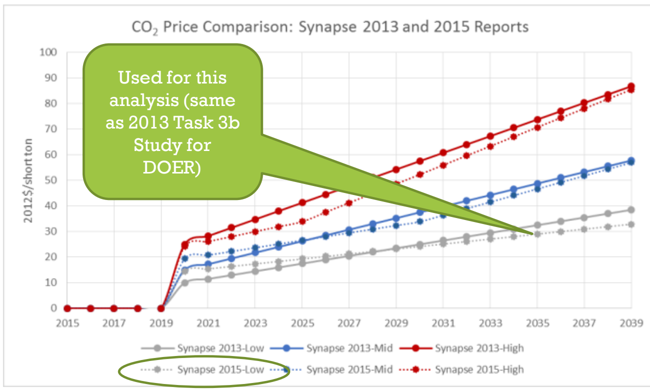
Capacity Value of Intermittent Resources

- Intermittent Resources per : ISO-NE Commercialization and Audit/CCA Establish Procedures for FCM resource (ISO-NE, Apr. 17, 2014)
  - Intermittent reliability hours
  - http://iso-ne.com/static-assets/documents/committees/comm_wkgrps/othr/vrwg/mtrls/a4_commercialization_and_audit.pdf
  - Comparative benchmark for SCC: See slide 20 of this:
    - http://www.iso-ne.com/static-assets/documents/2014/08/2014_final_solar_forecast.pdf
    - 35% SCC used by ISO for estimate

(18)

Internalized (Market) CO_2 Price Assumptions
Used in Dispatch Modeling

Potential Future Carbon Pricing or Equivalent LMP Impact of GHG Regs



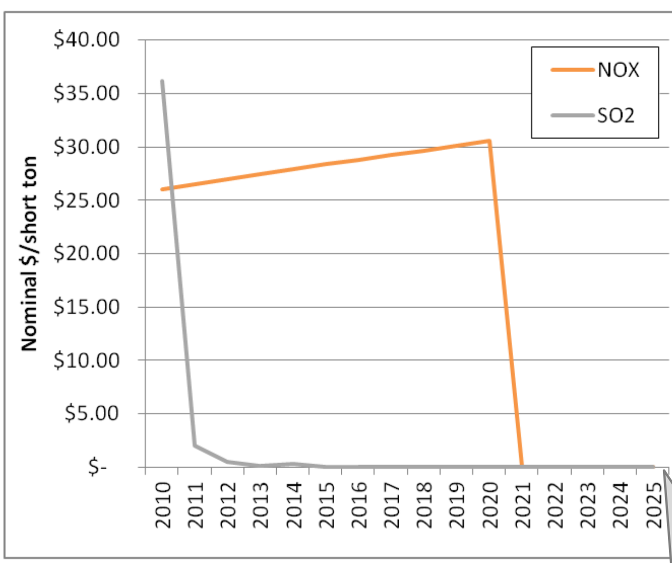
Note: Potential sensitivity of interest for further study: higher carbon price future

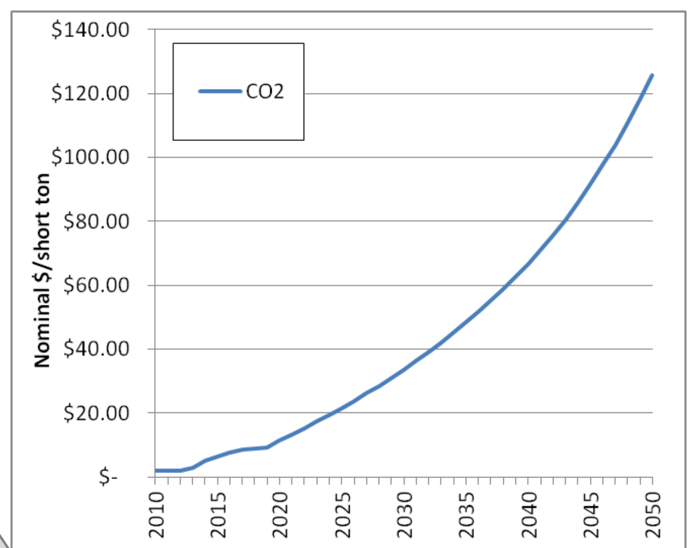
Used as a PROXY

- Start with: Regional Greenhouse Gas Initiative (RGGI) past and projected pricing (projections by ICF for RGGI)
- Transition after 2019 to Synapse Low as a proxy for some combination of future:
  - Federal cap & trade
  - Federal Clean Power Plan impact on energy costs
  - MA Global Warming Solutions Act (and other regional state carbon regs) impact on energy prices

(19)

Emission Pricing Assumptions for Dispatch Modeling

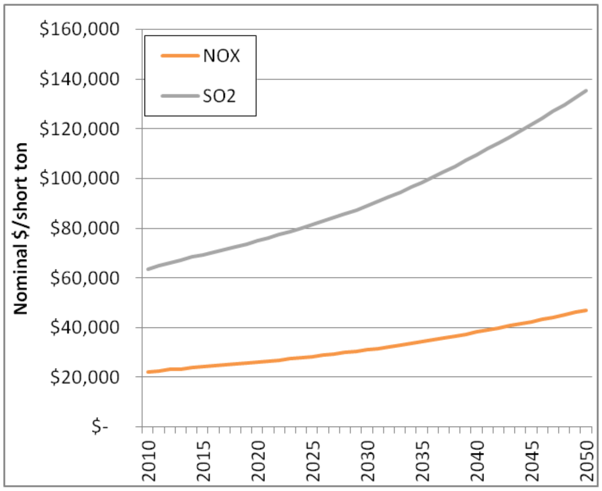


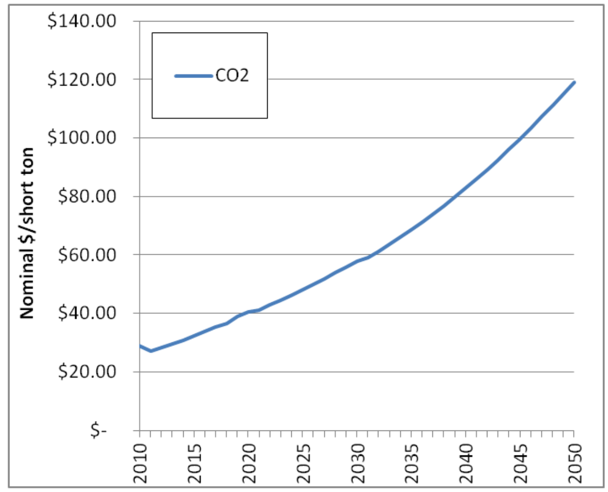


Remains $0 from 2025 onward

(20)

Gross Social Costs of Emissions





- Social costs of NO_X and SO_2 are taken from Table 4-7 of the 2014 EPA *"Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants"* report
- Social costs of CO_2 are taken from Table A-1 of the 2013 *"Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis"* prepared by U.S. Interagency Working Group on Social Cost of Carbon under Executive Order 12866

(21)

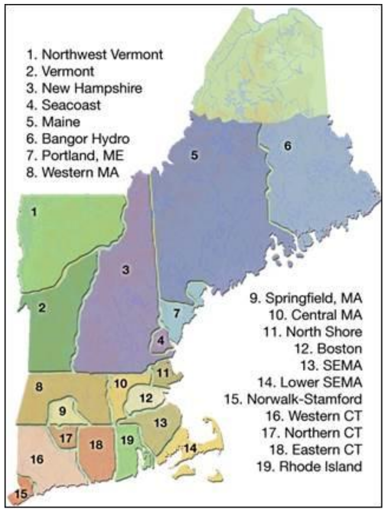
Production Modeling of Impacts (1)

- Case 1a: no policy: remove SREC-I & SREC-II production (keep pre-carve-out PV), assume Class I RPS is met by adding a commensurate amount of wind or (if fall short) natural gas
  - In past, before 1/1/2015 not modeled. Instead:
    - solar not replaced by other supply (onshore wind) but rather all the wind that could be built, was, so RPS supply came up shorter by the amount of SRECs projected, and replaced to the extent supply needed by natural gas
    - Fuel use and emissions changes not modeled; rather, calculated at marginal values
    - Was negligible congestion historically ➔ assume same marginal units (modeled as hypothetical NG unit at composite marginal heat rate
    - Assume no material change in LMPs
  - In future: through 2017 assume no more wind could be built, so substituted by falling short of RPS, met be marginal natural gas; 2018 & thereafter, assume PV substituting with land-based wind
- Case 1b: Assume RPS shortfall made up by natural gas
- Case 2a: 1600 MW by 2020
  - Buildout: Historic (from DOER) + projected (SEA MA-SMS in consultation w/ DOER)
- Case 2b: 1600 MW by 2020 continuing to 2500 MW by 2025
  - Buildout: Extrapolate normalized build per yr and round up to allow for a bit of growth
- Impacts calculated as differences:
  - SREC-I & SREC-II from difference between Case 1 & Case 2a
  - SREC-I, SREC-II & (projected) SREC-III from difference between Case 1 & Case 2b

(22)

Production Cost Modeling (2)

- Geographic distribution assumed to be same as current cumulative build
  - BOSTN = 11 North Shore + 12 Boston
  - CMA = 10 Central MA
  - WMA = 8 Western MA + 9 Springfield
  - SEMA = 13 SEMA + 14 Lower SEMA



- Note: the Aurora modeling was done using a slightly older SEA forecast (vintage Dec. 2014) of SREC Carve-out (current policy) than used for Policy Path A & B.
- SEA's March 2015 Solar Market Study model is better able to address the differential economics of alternative policy paths.
- March 2015 model projects hitting 1600 MW under current policy at a somewhat different pace.
- Use of per-MWH Aurora results scaled to SMS MWH projections used to correct for this difference.

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MA DOER Net Metering

Modeling Assumptions

Presented by: *La Capra Associates, Inc.* **Presented to:** **Sustainable Energy Advantage, LLC**

April 21, 2015

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Introduction: Modelling Overview

- The La Capra Associates NMM uses an hourly chronologic electric energy market simulation model based on the AURORAxmp® software platform (AURORA). The model provides a zonal representation of the electrical system of New England and the neighboring regions. For New England, the zones and corresponding transfer capabilities represented in the model conform to the information provided in ISO New England's Regional System Plan.
- AURORA is a well-established, industry-standard simulation model that uses and captures the effects of multi-area, transmission-constrained dispatch logic to simulate real market conditions. AURORA realistically approximates the formation of hourly energy market clearing prices on a zonal basis using all key market drivers, including fuel and emissions prices, loads, DSM, generation unit operating characteristics, unit additions and retirements, and transmission congestion and losses to capture the dynamics and economics of electricity markets.
- The NMM utilizes a comprehensive database representing the entire Eastern Interconnect, including representations of power generation units, zonal electrical demand, and transmission configurations. EPIS, the developer of AURORA, provides a default database, which La Capra Associates supplements with updates to key inputs for the New England market.

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Modeling Assumptions

- ❑ Case assumptions
- ❑ Environmental Policies
- ❑ Regional Demand and DSM
- ❑ Regional Generation
- ❑ Transmission
- ❑ Natural Gas

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Four cases run in Aurora

Case 1: No SREC Carve-out (removes MA SREC I and II) and replaces solar with wind resources beginning in 2018

Case 1b: No SREC Carve-out (removes MA SREC I and II)

Case 2a: 1600 MW of solar by 2020 (Current Policy)

Case 2b: 1600 MW of solar by 2020 and continuing to 2500 MW by 2025 with linear growth

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Environmental Policies

- **There are two major policy issues affecting the regional market outlooks.**
- **The two programs particularly impact decisions on generation resource continued operation and new supply choices.**

1. **The continued strong support for Renewable Portfolio Standards**
2. **The existing and developing GHG regulations**

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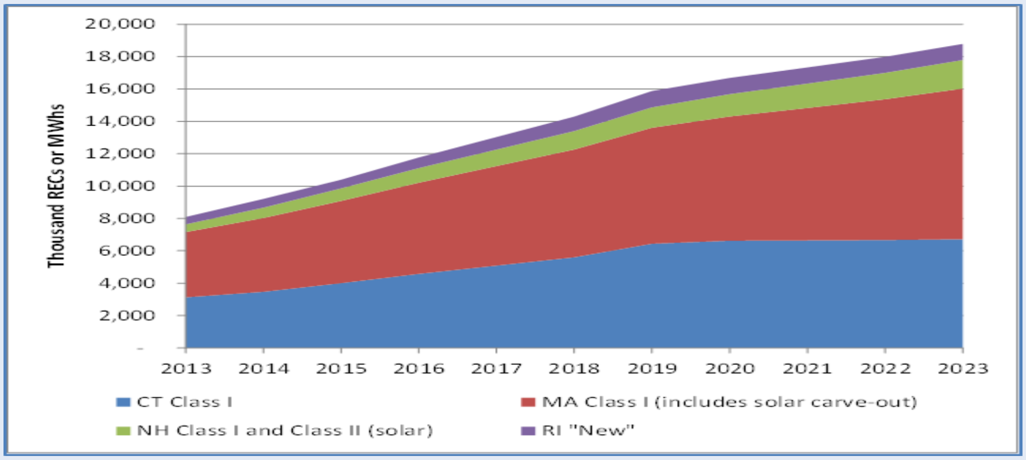
Renewable Energy - Premium Markets RPS

	2014	2015	2016	2017	2018	2019	2020	2021-2023
CT Class 1	11.0%	12.5%	14%	15.5%	17%	19.5%	20.0%	20.0%
MA Class 1	9%	10%	11%	12%	13%	14%	15%	16%+
NH Class 1	5.0%	6.0%	6.9%	7.8%	8.7%	9.6%	10.5%	11.4%+[1]
NH Class 2	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%
RI New	6.5%	6.5%	8.0%	9.5%	11.0%	12.5%	12.5%[2]	12.5%
Load-Weighted Average	9.0%	10.1%	11.2%	12.4%	13.6%	15.1%	15.9%	16.5%+



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Greenhouse Gas Regulations

RGGI

All New England states participate in RGGI, a cap-and-trade program aimed at reducing CO_2 emissions from the power sector. Pricing carbon emissions through a cap-and-trade program affects New England electric energy prices by increasing the variable costs of fossil fuel-fired generators that are almost always on the margin. RGGI allowance prices have been minimal since the program began in 2009 because actual CO_2 emission levels have fallen well below the initial program caps. On February 7, 2013 the RGGI states committed to an Updated Model Rule that would tighten the caps significantly in 2014. A RGGI-commissioned study of the Updated Model Rule projects that emission allowance prices will rise from about $4 (2010$) per ton in 2014 to over $10 (2010$) per ton by 2020.RGGI auction results to-date have benchmarked well to the Updated Model Rule forecast. After 2020, the reference case assumes that a national CO_2 pricing program is implemented and that prices will reflect the “Low” case of Synapse Energy Economics, Inc.’s 2012 Carbon Dioxide Price Forecast.

Federal Policy

EPA released its Clean Power Plan proposal, which aims to cut carbon emissions from existing power plants and enable the US to reduce carbon emissions from the power sector by 30% below 2005 levels. EPA has proposed each state or multi-state collaboration would develop a plan to meet an individual carbon intensity reduction target through any combination of plant efficiency improvements, shifting generation from higher to lower-emitting resources, maintaining and expanding nuclear and renewable generation, and energy efficiency. New England has already implemented programs and policies that would likely generate more carbon dioxide reductions than required under the EPA’s proposal, but the federal proposal would backstop these efforts.

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Regional Electric Demand – Gross Outlook Pre - EE

ISO-NE Peak Demand Outlook

2013 Normalized Demand		Actual 27,941	MW
2014 Forecasted Demand		28,290	MW
2023 Forecasted Demand		31,878	MW
10 Year CAGR			1.4 %
10 Year Increase	3,937 MW	11% of 2023 Demand	

ISO-NE Energy Requirements Outlook

2013 Energy		*est. 135,000*	GWh
2014 Forecasted Energy		138,910	GWh
2023 Forecasted Energy		152,347	GWh
10 Year CAGR			0.7%
10 Year Increase	3,006 GWh	10% of 2023 Energy	

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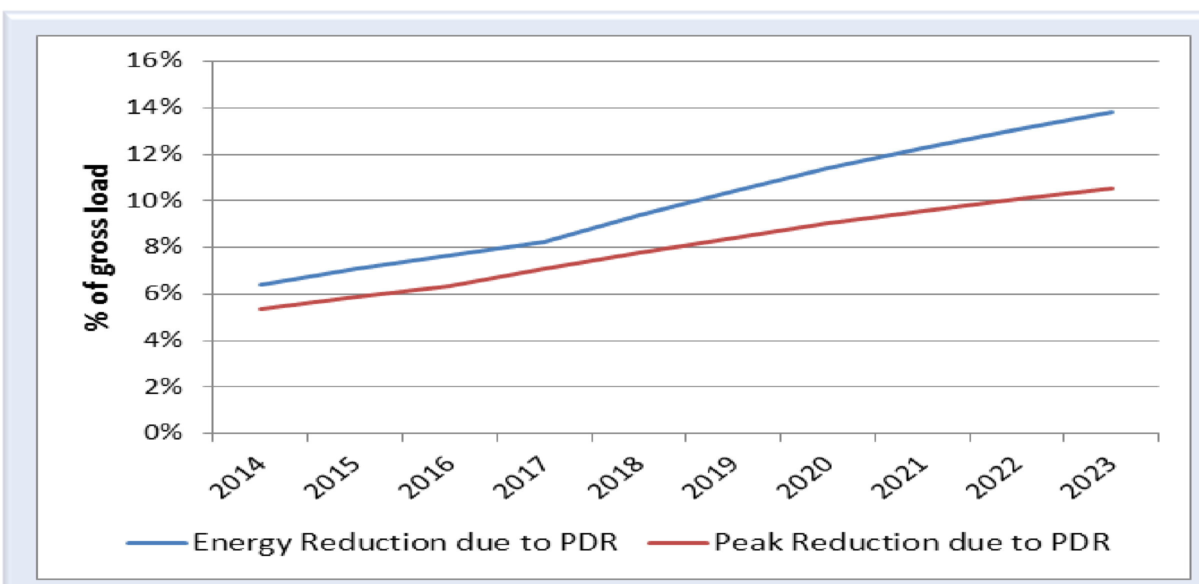
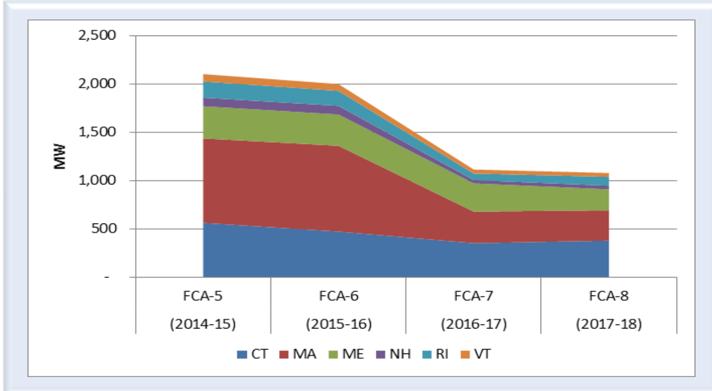
Energy Efficiency Resources



Active Demand Response Resources

- There has been a major reduction in the amount of active DR available to ISO-NE by 201-18
- Total reductions are approximately 1,000 MW
- Proportionately largest reduction in Massachusetts
- This is primarily a result of the new rules requiring DR participation in energy markets
- Further operational requirements on DR could virtually eliminate DR as an FCA resource



Regional Electric Demand – Net Outlook after EE Effects

ISO-NE Peak Demand Outlook

2013 Normalized Demand	*est 26,000*	MW
2014 Forecasted Demand	26,929	MW
2023 Forecasted Demand	29,206	MW
10 Year CAGR		0.7 %
10 Year Increase	3,006	MW

ISO-NE Energy Requirements Outlook

2013 Energy	*est. 134,000*	GWh
2014 Forecasted Energy	131,037	GWh
2023 Forecasted Energy	134,786	GWh
10 Year CAGR		0.1 %
10 Year Increase	786	GWh

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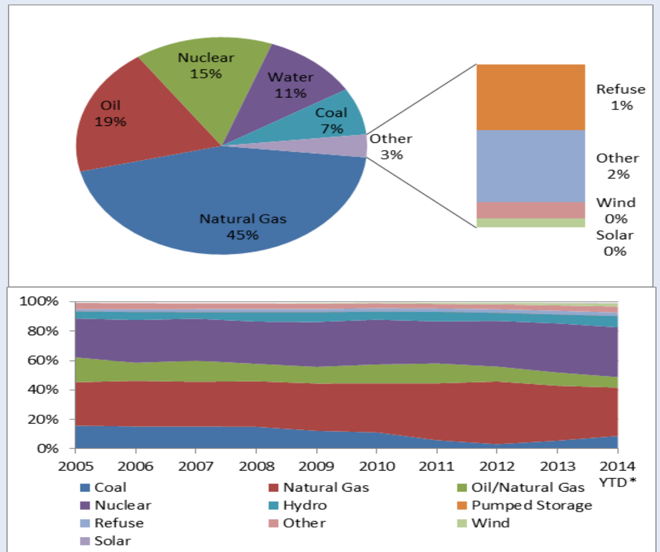
Generation Mix

- New England remains a natural gas fueled dependent region
- Renewables have not yet been established as a major component of generation mix
- Natural Gas share of energy increased every year until its highest in 2012, before regional constraints began to push natural gas prices upward



*Includes data through May 2014

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Generation Resource Retirements

Name	Capacity (MW)	Location	Fuel Type	Status	Planned or Actual Shutdown
Vermont Yankee	600	Vernon, VT	Nuclear	Shutdown Announced	End of 2014
Brayton Point (Units 1-4)	1,500	Somerset, MA	Coal/Oil	Shutdown Announced	2017
Salem Harbor (Units 1-4)	750	Salem, MA	Coal/Oil	Closed	2011-2014
AES Thames	450	Montville, CT	Coal	Demolition	2011
Mt. Tom	150	Holyoke, MA	Coal	Shutdown Announced	2014
Bridgeport Harbor 2	130	Bridgeport Harbor, CT	Oil	Shutdown Announced	2017
Norwalk Harbor (Units 1, 2, 10)	350	Norwalk, CT	Oil	Deactivated	2013

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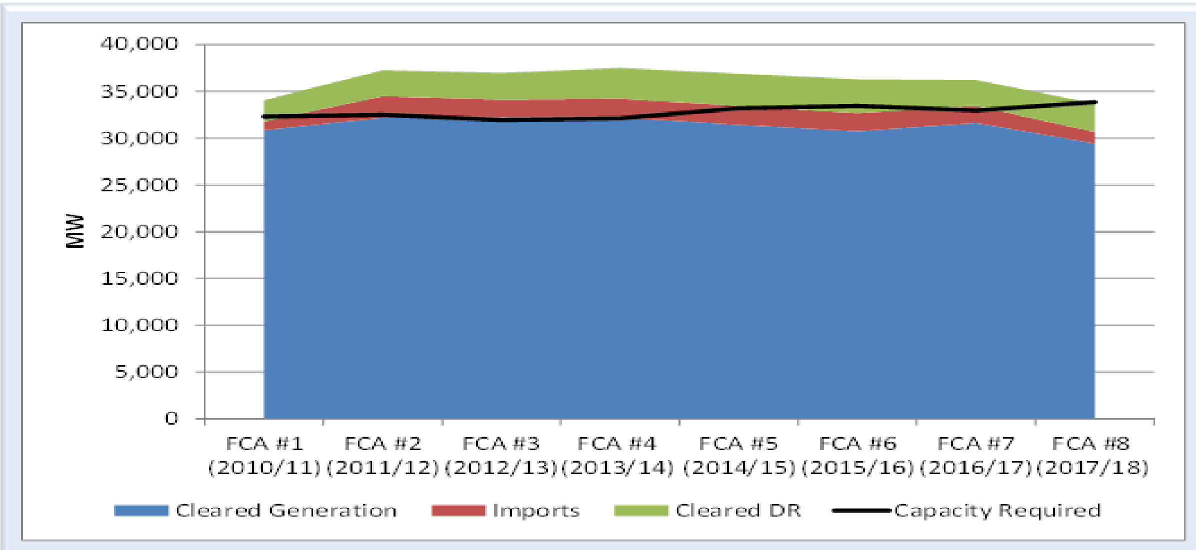
Regional Capacity Outlook

ISO-NE FCA Results showing slight shortfall in 2017/18



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Regional Transmission Developments

There are several other transmission projects currently planned or under construction in New England:

- **Maine Power Reliability Program:** six new substations, upgrades to numerous existing substations, and the installation or rebuilding of 440 miles of transmission line in the communities from Eliot to Orrington in Maine. Expected in service date is 2015.
- **New England East-West Solution:** a group of related transmission projects addressing reliability needs in New England, including:
  - **The Greater Springfield Reliability Project:** upgrades to 39 miles of transmission lines between Ludlow, MA and Bloomfield, CT. Now fully in service.
  - **The Interstate Reliability Project:** transmission upgrades spanning three states on a line from Millbury, MA to Card Street Substation in Lebanon, CT. Expected in service date is December 2015.
  - **Central Connecticut Reliability Project:** a project currently in development to remedy reliability concerns in the central Connecticut area**.**
  - **Rhode Island Reliability Project:** includes several transmission upgrades in Rhode Island, including a new 345 kV line from West Farnum to Kent County. Now in service.
- **Boston Upgrades:** transmission upgrades due to the retirement of Salem Harbor and advanced NEMA/B**oston upgrades increasing Boston import capability in 2014.**

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Natural Gas Pricing Methodology

- ***Henry Hub:*** **Prices are a blend of EIA's December 2014 Short-Term Energy Outlook (2013-2015) and EIA's 2014 Annual Energy Outlook (AEO) (2015 and after). In the early years, we rely on the Short-Term Energy Outlook. For years 2017 and 2021, we smooth our forecast by assuming that the price rises at a constant rate. In 2021 and beyond, our forecast follows the AEO2014 exactly.**
- ***New England Basis Differential:*** **We developed our near-term basis differential outlook using the average across a recent one year period (1/6/14 – 1/5/15) of daily closing quotes for February 2015 to January 2016 Algonquin City-gates basis swaps. In 2018 and beyond, we revert to a basis that results in a delivered natural gas price equal to the AEO2014 Reference Case forecast for delivered prices to the New England electric industry. We make a straight-line interpolation for basis differential values between 2015 and 2018.**

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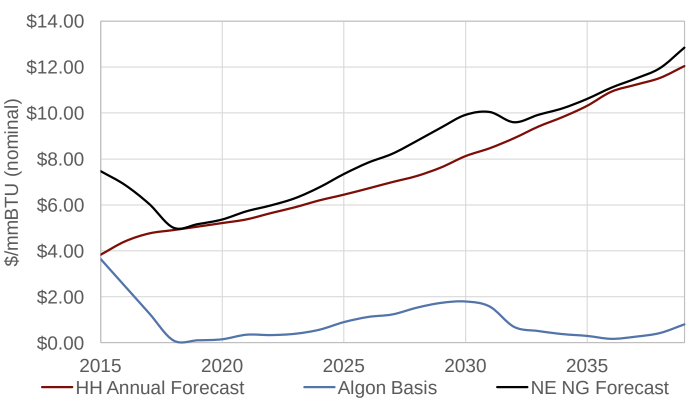
Natural gas price inputs in nominal dollars



Year	HH Annual Forecast	Algon Basis	NE NG Forecast
2015	$3.83	$3.64	$7.47
2016	$4.41	$2.46	$6.87
2017	$4.76	$1.28	$6.04
2018	$4.91	$0.10	$5.01
2019	$5.06	$0.11	$5.17
2020	$5.21	$0.15	$5.37
2021	$5.37	$0.35	$5.72
2022	$5.64	$0.34	$5.98
2023	$5.90	$0.39	$6.30
2024	$6.20	$0.57	$6.77
2025	$6.45	$0.90	$7.34
2026	$6.72	$1.12	$7.84
2027	$7.00	$1.23	$8.23
2028	$7.26	$1.53	$8.79
2029	$7.63	$1.73	$9.37
2030	$8.12	$1.79	$9.92
2031	$8.47	$1.57	$10.04
2032	$8.91	$0.69	$9.60
2033	$9.41	$0.51	$9.92
2034	$9.83	$0.38	$10.21
2035	$10.31	$0.30	$10.61
2036	$10.93	$0.17	$11.10
2037	$11.23	$0.27	$11.50
2038	$11.53	$0.43	$11.96
2039	$12.04	$0.80	$12.84

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End of Presentation

Additional Discussion or Questions ?

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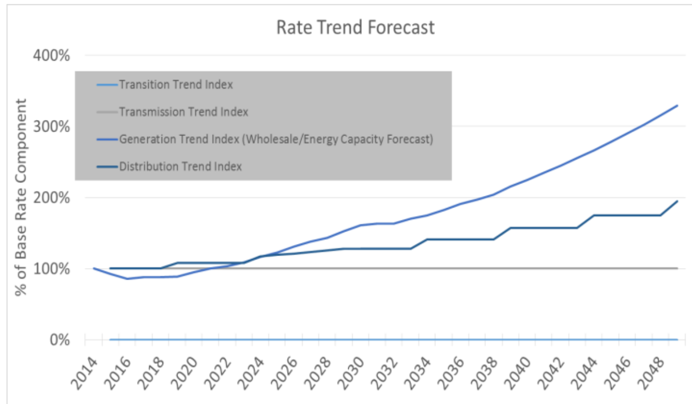
D. AVOIDED RETAIL RATES AND NET METERING REVENUES

AND RELATED ASSUMPTIONS

(42)

Rate Trend Forecast:
Assume no fundamental change in rate structures over time

- **Transition** assumed to be 0% escalation after 2015, per EDCs
- **Transmission** assumed to be fixed (0% escalation), per EDCs
- **Distribution** assumed to increase by inflation in steps (corresponding to rate cases) every 5 years, per EDCs
- **Generation** assumed to escalate at index of wholesale blended energy (75%)/capacity (25%)* trend forecast
- **Other Rate Components**: Increase with Inflation, per EDCs
- Recent difference between wholesale energy prices and Basic Service generation rates applied to factor in impact of capacity, reserves, losses, etc.
  - Average of 2014 basic service rates (two procurements) used as the base for forecasting generation charge to avoid overstatement due to unusually high 2015 winter basic service rates

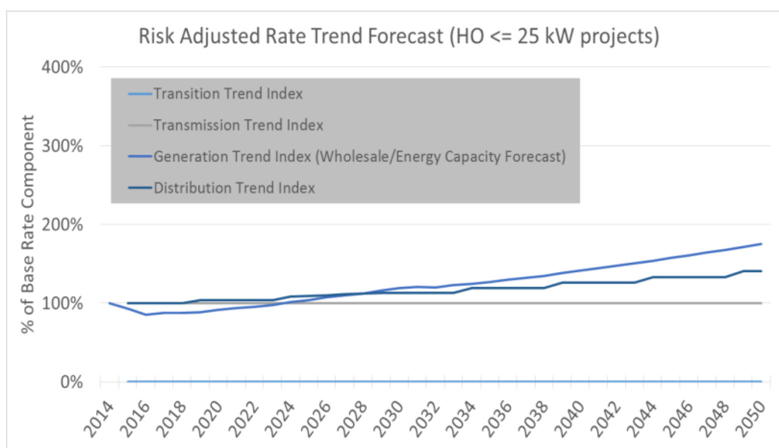


* Portion of spread to trend @ Energy vs. capacity escalator

(43)

Rate Trend Forecast:
For Modeling Project Threshold Return Requirements

- Generators cannot take the uncertain projected retail revenue stream, dependent on long-term factors like carbon pricing, natural gas pricing and capacity market prices, which cannot be relied upon, to the bank
- For 3rd-party owned projects, this risk can and often is hedged (i.e., passed along to the host or NMC off-taker through a fixed-price transaction). We assume going forward that this risk is hedged in such a manner for all 3rd-party owned systems
- For host-owned small projects (<= 25 kW) under SREC and Policy Path B, we assume project owner is exposed to future retail price risk, and makes choices based on a more conservative outlook of future retail rates
- Modeled more conservative future by halving the year-to-year growth in prior slide of **generation** and **distribution** rates after 2018
- Otherwise, under PBIs as studied in Paths A and B, the combined incentive structure serves to hedge this risk



(44)

‘Generic” Municipal Light Plant Modeling

- Municipal light territories are modeled in aggregate
- Net metering credit assumed to be load-weighted average of a sample of 10 MLP NMC values (Taunton rates were used as proxy to differentiate G rate from other charges)
  - NMC escalated at wholesale/energy capacity forecast index
- Residential and commercial retail rates calculated as the ratio of EIA “loaded” $/MWh (includes non-kWh charges) of IOUs to MLPs applied to the actual “unloaded” IOU retail rates
  - 40% of MLP retail rate escalated by wholesale/energy capacity forecast index
  - 60% of MLP retail rate escalated by CPI
- Assume 13% of installations in 2015 are in MLPs - based on historic installation trends
- For calculating rate component value, assume MLP rates are made up of basic service (40%), distribution (40%), and transmission(20%)

Errata Note: rates used were 20% higher than avg. MLP. This was an error discovered too late in the analysis for revision. Correction of this error would modify results in the following manner: overall growth in installations in the MLP sector would slow moderately, and the overall cost of solar incentives would be slightly higher. This does not alter the nature of overall conclusions in a material manner.

(45)

Applicable Rate Class & Net Metering Class Assumptions

Description	Rate Class	% NM Beyond Billing Month/VNM	% BTM Production w/in Billing Month	Net Metering Class Assumed		
				3rd Party	Host Owned	Public Owned
Residential Roof Mount	R-1	10%	90%	Class 1		
Small Commercial Roof Mount	G-1	5%	95%	Class 1		
Solar Canopy	G-1	5%	95%	Class 2		
Commercial Emergency Power	G-1	5%	95%	Class 1		
Community Shared Solar	G-1	100%	0%	Class 2		
On-Site LIH	G-2	5%	95%	Class 2		
VNM LIH	G-1	100%	0%	Class 2		
Building Mounted	G-2	5%	95%	Class 2		
Small/Medium Ground Mount BTM	G-2	5%	95%	Class 2		
Large Ground Mount BTM	G-2	5%	95%	Class 3		Class 2
Small/Medium Landfill	G-1	100%	0%	Class 2		
Large Landfill	G-1	100%	0%	Class 3		Class 2
Small/Medium Brownfield	G-1	100%	0%	Class 2		
Large Brownfield	G-1	100%	0%	Class 3		Class 2
Medium Ground Mount VNM	G-1	100%	0%	Class 2		
Medium MG	G-1	100%	0%	Class 2		
Large MG	G-1	100%	0%	Class 3		Class 2

Net Metering Credit Rates

- Net meter credits are equal to the following components based on the project type net metering class:

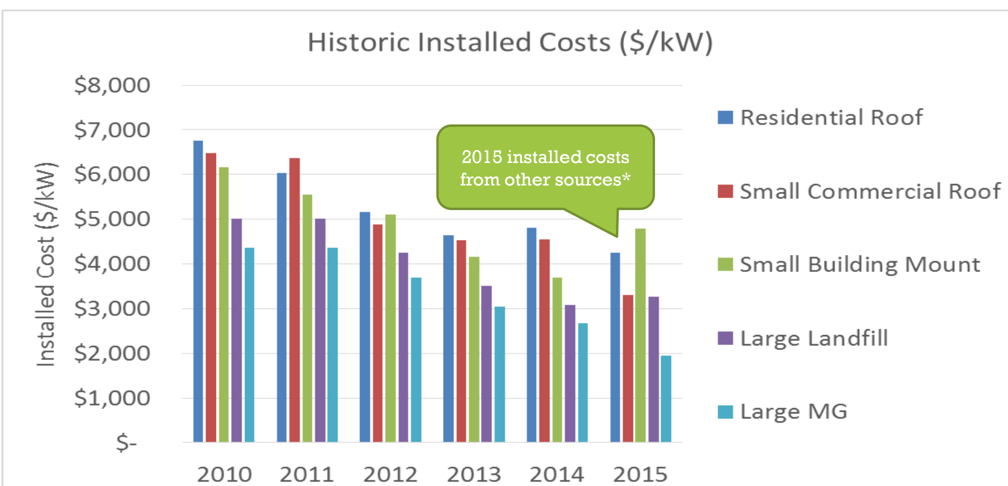
Net Metering Class	Components
Class 1	Generation + Distribution + Transition + Transmission
Class 2	Generation + Distribution + Transition + Transmission
Class 3	Generation + Transition + Transmission

- Small (<= 25 kW) projects always receive net metering (whether uncapped or capped scenario)
- In **Policy Path A** net metering credits are equal to the generation component only

(47)

Historic Installed Costs

- Use DOER SREC-I and SREC-II SQA installed cost data to find the average annual residential installed costs and non-residential by size block for 2010 to 2014



* Discussed in detail PV System Costs section of Appendix

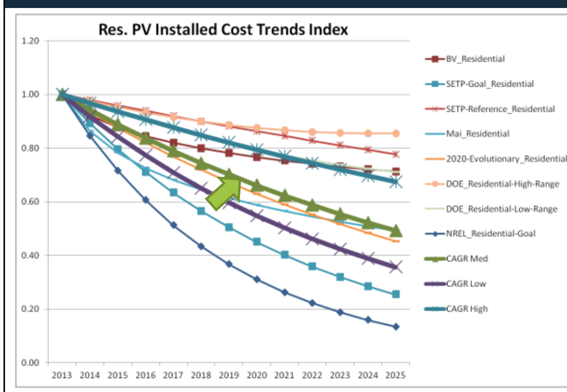
(52)

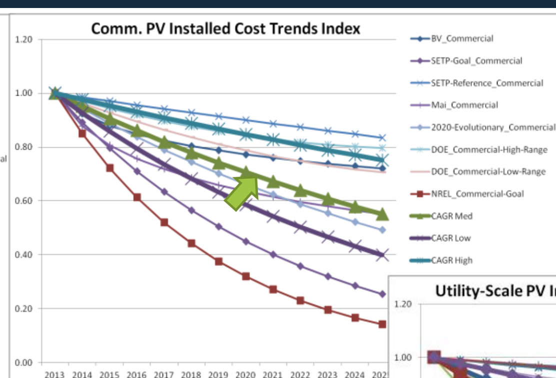
Historic:
Other PV System Costs & Rates

- O&M, customer acquisition, and interconnection costs were backcasted by extrapolating the CPI to 2010 and applying the index to 2015 costs
- Fixed costs (lease payments & PILOT/property taxes) assumed to be fixed back to 2010
- Actual 2010 to 2014 rates for each utility were used to calculate net metering and retail value of production

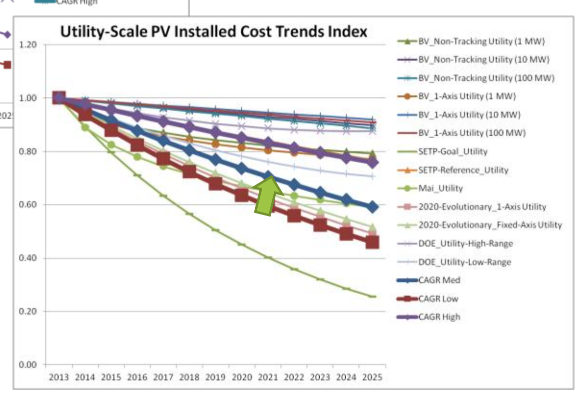
(53)

Installed Cost Forecasts: Trends





Note: No explicit adjustments made for impact of import duties; Overall impact on module price ~ 8¢/W (per SEAI), portion in effect during 2014 already embedded in forecast

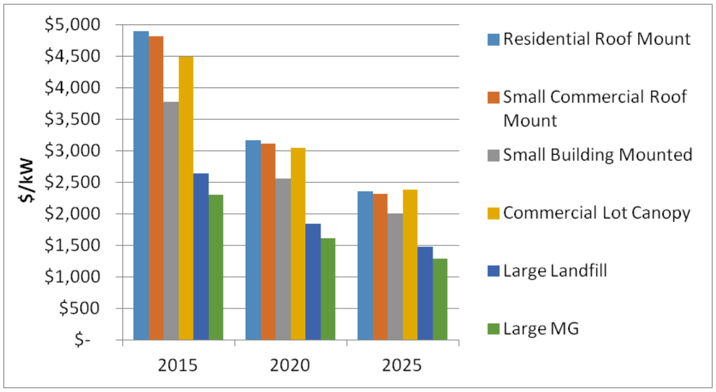


- Survey of available public sources as of late 2014 considered
- Developed trajectory as an index, applied over analysis period to applicable recent historic installed cost data
- 'Medium' used as base case for this analysis

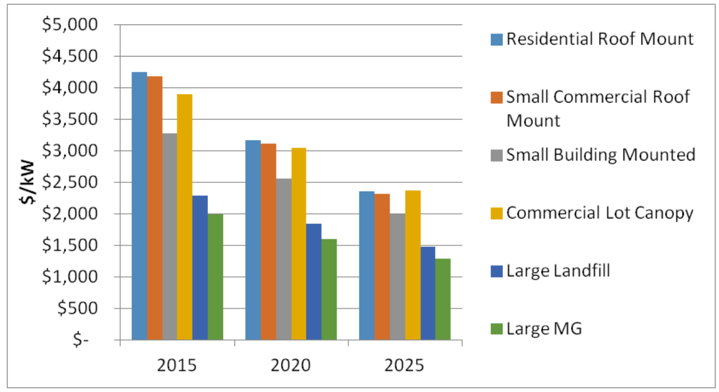
(54)

Installed Costs

Host Owned and Public Owned



Third-Party Owned



- The following blocks were also modeled: Campus Lot Canopy, Commercial Emergency Power, Community Shared Solar, On-Site LIH, VNM LIH, Medium Building Mounted, Large Building Mounted, Medium Ground Mount BTM, Large Ground Mount BTM, Small Landfill, Medium Landfill, Small Brownfield, Medium Brownfield, Large Brownfield, Medium Ground Mount VNM, Medium MG
- Blocks of high and low cost systems were also modeled (the above figures represent average cost systems)

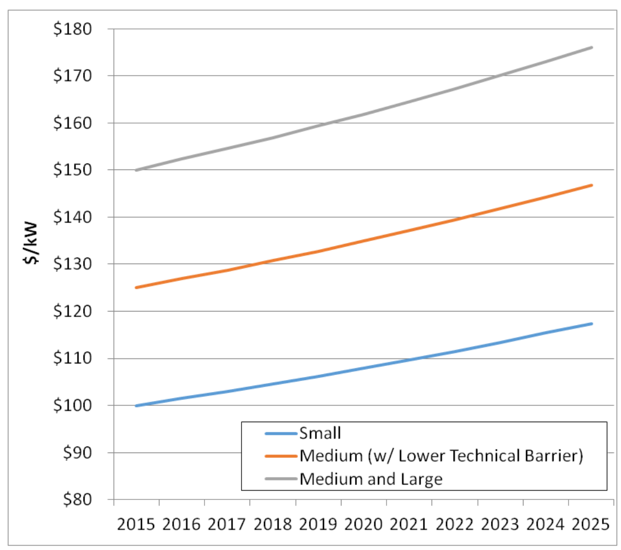
(55)

Interconnection Cost Assumptions

- Based on historical data from public sources and supplemental research
- Assumed interconnections costs vary by project size and technical barrier to interconnect
- Year 1 Interconnection Costs:

Project Size	Modeled Blocks	Year 1 Cost
Small	Residential Roof Mount, Small Commercial Roof Mount, Commercial Lot Canopy, Commercial Emergency Power, On-Site LIH, Small Building Mounted	$100/kW
Medium (with Lower Technical Barrier)	Medium Building Mounted, Medium Ground Mount BTM	$125/kW
Medium and Large	Campus Lot Canopy, Community Shared Solar, VNM LIH, Large Building Mounted, Large Ground Mount BTM, Small Landfill, Medium Landfill, Large Landfill, Small Brownfield, Medium Brownfield, Large Brownfield, Medium Ground Mount VNM, Medium MG, Large MG	$150/kW

- Escalated annually by CPI
- Assumed same interconnection costs across ownership models



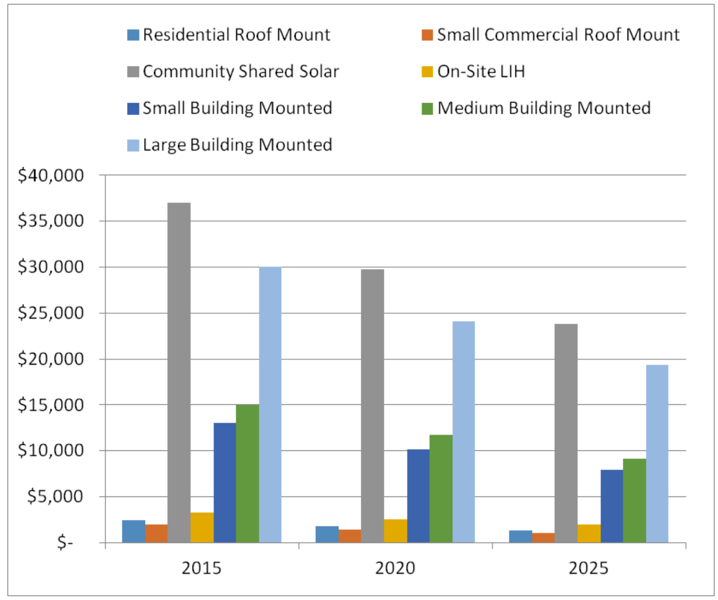
(56)

Customer Acquisition Cost Assumptions

- Based on NREL SunShot soft cost estimates
- Year 1 Customer Acquisition Costs:

Project Type	Year 1 Cost ($/kW)
Residential	$480
Small Commercial	$130
Large Commercial	$30

- Escalated annually using Installed Cost Forecast
- Only applied to third-party owned projects
- Assumed no Customer Acquisition Costs for Canopy, VNM LIH, and Ground Mounted projects



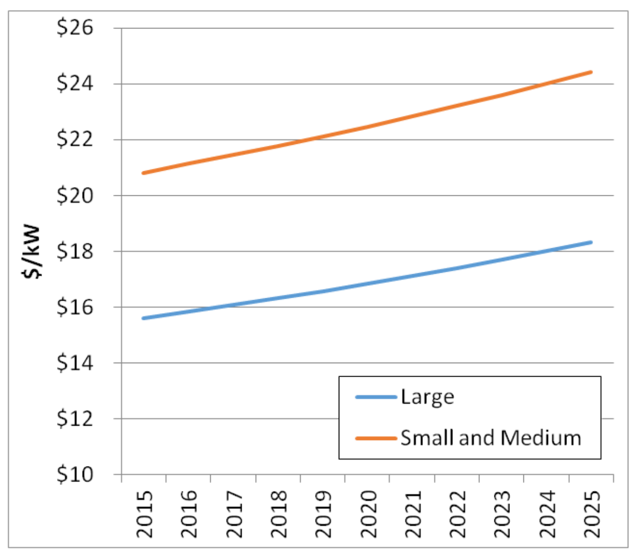
(57)

O&M Cost Assumptions

- Based on historical data from public sources and supplemental research
- Assumed O&M costs "fixed" based on system size not performance
- Assumed O&M costs vary by project size ➔ larger projects will have lower $/kW O&M costs
-

Project Size	Modeled Blocks	Year 1 Cost
Large	Community Shared Solar, VNM LIH, Large Ground Mount BTM, Medium Landfill, Large Landfill, Medium Brownfield, Large Brownfield, Medium MG, Large MG	$16/kW
Small and Medium	Residential Roof Mount, Small Commercial Roof Mount, Commercial Lot Canopy, Campus Lot Canopy, Commercial Emergency Power, On-Site LIH, Small Building Mounted, Medium Building Mounted, Large Building Mounted Medium Ground Mount BTM, Small Landfill, Small Brownfield, Medium Ground Mount VNM	$21/kW

- Escalated annually by CPI
- Assumed same O&M costs across ownership models



(58)

Property Tax (PILOT) and Land Lease Cost Assumptions

- Assumptions developed through market analysis and benchmarking
- PILOT Costs
  - Base Case assumed $10/kW per year, fixed over time
  - Assumed constant across all ownership models
  - Only applied to Ground Mount (incl. Landfill and Brownfield) projects
- Land Lease Costs
  - Base Case assumed $13/kW per year, fixed over time
  - Assumed constant across all ownership models
  - Not applied to Roof Mount projects

(59)

Financing Assumptions:
Related to Risk under each Policy

- For modeling, use simplified capital structure
- Debt:
  - Host & 3rd-party owned systems: on commercial terms
  - Publicly-owned projects: Based on long-term municipal bonds
- Equity
  - Initial developer/sponsor: cash + sweat equity
  - Tax equity to fully monetize tax benefits as generated
  - Where long-term contracts provide stable revenue, YieldCos emerge as another viable source of capital
- Cost & availability of capital is assumed sensitive to:
  - Contract quantity and duration
  - Type, duration & magnitude of incentive
    - Greater revenue certainty → lower cost of capital
    - Fixed PBI is likely to generate interest from more capital, at a lower cost, than a downward sloping soft price floor
- Modeling reflects:
  - Increasing competition among equity providers, including availability and applicability of YieldCo & similar investment vehicles
    - Downward pressure on cost of capital over time
  - Impact of transition from 30% to 10% ITC on capital structure and cost of capital
  - Expiration of ITC for residential host-owned
  - Impact of MA residential solar loan program for small portion of residential installations
    - Implemented as slight interest rate reduction to all residential host-owned projects
  - Considering the degree to which cost of capital advantage of fixed price PBI vs. SREC floor price shrinks as proportion of uncertain revenue shrinks
    - At the limit, if discount to floor is sufficient to finance, cost of capital advantage vanishes

(60)

Financing Assumptions:
Derivation & Application of Key Inputs

	Private, 3rd-Party	Private, Host-Owned	Public, Host-Owned
% Debt	Based on maximum sustainable debt, subject to DSCR (average = 1.35); > rev. certainty (PBI) means > leverage; Debt % also ↑ as ITC % ↓	Estimate of corporate financing structure for major capital investments	Assumed to finance 100% of cost through municipal bonds
Debt Term	Est. of commercial terms. Shorter for SREC structure, longer for PBI	Est. of corporate financing, with guarantee. Term longer for PBI than SREC	20 year bond, all market structures
Int. Rate	Term-specific risk free rate plus market-based premium; assumes volume discount compared to one-off project	Term-specific risk free rate plus market-based premium; rates higher than Private, 3rd-Party due to one-off nature	20-year municipal bond market
Loan Fee	An origination fee, paid to the lender. Set at a level which approximates the market-based premium above the base debt interest rate. For Private, Host-Owned the Loan Fee is assumed built into the term debt interest rate.		
% Equity	All remaining funds required after maximum sustainable debt; a blend of cash, tax and YieldCo equity; blend changes as ITC is reduced	Est. of corporate financing, with guarantee.	Not applicable. Projects financed 100% with municipal bonds.
AT Wtd Cost of Equity	A weighted average of cash, tax and YieldCo equity; subject to downward (competitive) pressure over time	Est. of corporate opportunity cost of other capital investments	Not applicable
WACC	= (%e * Ke) + (%d*Kd*(1-Tax Rate)) The project-specific WACC is used to convert the PBI into an equivalent EPBI (rebate).		Not applicable

(61)

Financing Assumptions: SREC
Private, 3rd-Party Ownership

kW	< 25			100			500			1,000			2,000+		
	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25
% Debt	40%	50%	50%	40%	50%	50%	40%	50%	50%	40%	55%	55%	40%	55%	55%
Debt Term	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
Int. Rate	5.50%	5.75%	6.00%	5.50%	5.75%	6.00%	5.50%	5.75%	6.00%	5.50%	5.75%	6.00%	5.50%	5.75%	6.00%
Loan Fee	2.00%	2.00%	2.25%	2.00%	2.00%	2.25%	2.00%	2.00%	2.25%	2.00%	2.00%	2.25%	2.00%	2.00%	2.25%
% Equity	60%	50%	50%	60%	50%	50%	60%	50%	50%	60%	45%	45%	60%	45%	45%
AT Wtd Cost of Equity	9.5%	8.4%	8.1%	9.5%	8.4%	8.1%	8.9%	8.4%	8.1%	8.9%	7.8%	7.6%	8.9%	7.8%	7.6%
WACC	7.0%	5.9%	5.8%	7.0%	5.9%	5.8%	6.9%	5.9%	5.8%	6.7%	5.4%	5.4%	6.7%	5.4%	5.4%

(62)

Financing Assumptions: SREC
Private Host Ownership

kW	< 25			100			500			1,000			2,000+		
	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25
% Debt	50%	50%	50%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%
Debt Term	15	15	15	12	12	12	12	12	12	12	12	12	12	12	12
Int. Rate	6.50%	6.75%	7.00%	6.50%	6.75%	7.00%	6.00%	6.25%	6.50%	6.00%	6.25%	6.50%	6.00%	6.25%	6.50%
Loan Fee	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
% Equity	50%	50%	50%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%
AT Wtd Cost of Equity	8.0%	8.0%	8.0%	12.0%	10.5%	9.0%	12.0%	10.5%	9.0%	12.0%	10.5%	9.0%	12.0%	10.5%	9.0%
WACC	5.9%	6.0%	6.1%	9.6%	8.6%	7.6%	9.5%	8.5%	7.5%	9.5%	8.5%	7.5%	9.5%	8.5%	7.5%

(63)

Financing Assumptions: SREC
Public host Ownership

kW	< 25			100			500			1,000			2,000+		
	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25
% Debt	-	-	-	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Debt Term	-	-	-	20	20	20	20	20	20	20	20	20	20	20	20
Int. Rate	-	-	-	3.5%	3.75%	4.00%	3.5%	3.75%	4.00%	3.5%	3.75%	4.00%	3.5%	3.75%	4.00%
Loan Fee	-	-	-	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%
% Equity	-	-	-	0	0	0	0	0	0	0	0	0	0	0	0
AT Wtd Cost of Equity	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WACC	-	-	-	3.5%	3.75%	4.00%	3.5%	3.75%	4.00%	3.5%	3.75%	4.00%	3.5%	3.75%	4.00%

(64)

Financing Assumptions: PBI
Private, 3rd-Party Ownership

kW	< 25			100			500			1,000			2,000+		
	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25
% Debt	50%	60%	60%	50%	60%	60%	50%	60%	60%	50%	65%	65%	50%	65%	65%
Debt Term	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
Int. Rate	6.00%	6.25%	6.50%	6.00%	6.25%	6.50%	6.00%	6.25%	6.50%	6.00%	6.25%	6.50%	6.00%	6.25%	6.50%
Loan Fee	2.00%	2.00%	2.25%	2.00%	2.00%	2.25%	2.00%	2.00%	2.25%	2.00%	2.00%	2.25%	2.00%	2.00%	2.25%
% Equity	50%	40%	40%	50%	40%	40%	50%	40%	40%	50%	35%	35%	50%	35%	35%
AT Wtd Cost of Equity	7.6%	7.1%	7.2%	7.6%	7.1%	7.2%	7.1%	6.7%	6.9%	7.3%	6.8%	7.0%	7.3%	6.8%	7.0%
WACC	5.6%	5.1%	5.2%	5.6%	5.1%	5.2%	5.3%	4.9%	5.1%	5.5%	4.8%	5.0%	5.5%	4.8%	5.0%

(65)

Financing Assumptions: PBI
Private Host Ownership

kW	< 25			100			500			1,000			2,000+		
	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25
% Debt	50%	60%	60%	50%	60%	60%	50%	60%	60%	50%	65%	65%	50%	65%	65%
Debt Term	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
Int. Rate	6.50%	6.75%	7.00%	6.50%	6.75%	7.00%	6.00%	6.25%	6.50%	6.00%	6.25%	6.50%	6.00%	6.25%	6.50%
Loan Fee	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
% Equity	50%	40%	40%	50%	40%	40%	50%	40%	40%	50%	35%	35%	50%	35%	35%
AT Wtd Cost of Equity	7.0%	7.0%	7.0%	10.0%	10.0%	9.0%	10.0%	10.0%	9.0%	10.0%	10.0%	9.0%	10.0%	10.0%	9.0%
WACC	5.4%	5.2%	5.3%	6.9%	6.4%	6.1%	6.8%	6.2%	5.9%	6.8%	5.9%	5.7%	6.8%	5.9%	5.7%

(66)

Financing Assumptions: PBI
Public host Ownership

kW	< 25			100			500			1,000			2,000+		
	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25
% Debt	-	-	-	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Debt Term	-	-	-	20	20	20	20	20	20	20	20	20	20	20	20
Int. Rate	-	-	-	3.5%	3.75%	4.00%	3.5%	3.75%	4.00%	3.5%	3.75%	4.00%	3.5%	3.75%	4.00%
Loan Fee	-	-	-	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%
% Equity	-	-	-	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
AT Wtd Cost of Equity	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WACC	-	-	-	3.5%	3.75%	4.00%	3.5%	3.75%	4.00%	3.5%	3.75%	4.00%	3.5%	3.75%	4.00%

(67)

F. SREC POLICY ASSUMPTIONS

SREC-I, II AND III

(68)

Modeling Extension of Current Policy: SREC-III

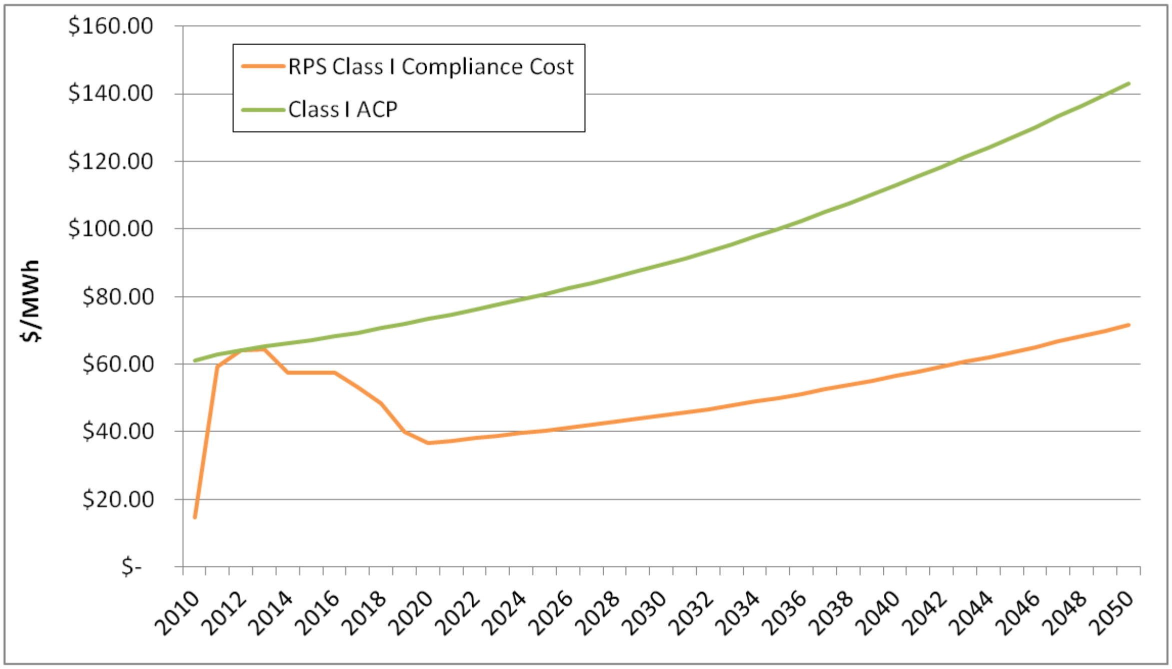
- Treated SREC-III from 1601 MW to 2500 MW dc as a separate tier, so as to not impact SREC-II expected prices and dynamics
- Extended the trend of SACP and floor price declines from those built into SREC-II policy
- Set and used annual MW targets with the objective of getting to 2500 MW by 2025, starting at the market size in last year of SREC-II with small escalator, in an analogous manner to SREC-II
- Modified SEA's proprietary Massachusetts Solar Market Study model of SREC-II with the above changes, using projected system costs and rates, to produce forecasted market buildout and prices.
- *Note: in modeling, SREC-III did not follow the targets, as sectors that were not 'managed' outstripped their targets and led to reaching 2500 MW well before 2025*

(69)

G. CLASS I RPS

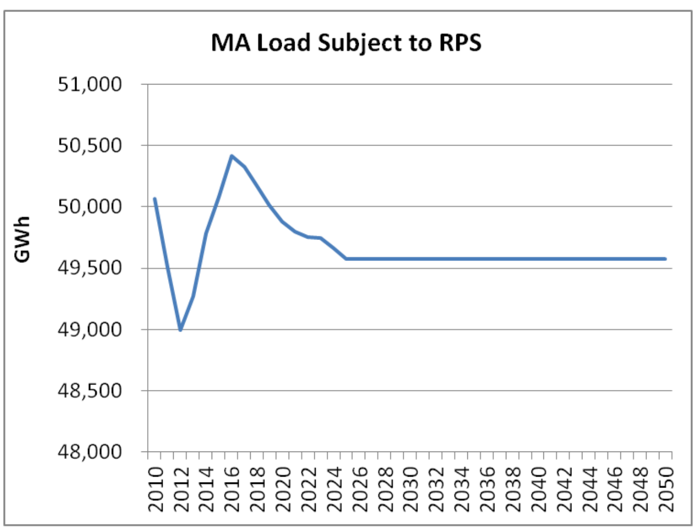
(70)

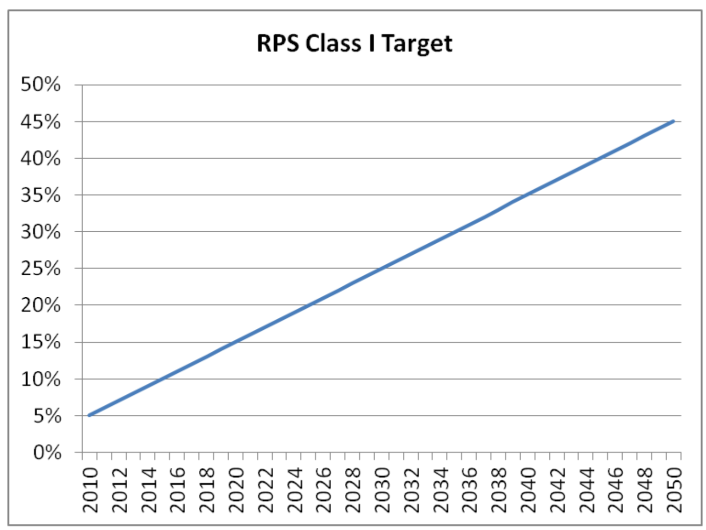
ACP and Avoided Class I RPS Compliance Costs



(71)

MA RPS Load, RPS Exemptions and Class I Targets





- RPS Exemptions = 17.27% of annual load

(72)

H. SUPPLY CURVE

APPROACH AND ASSUMPTIONS

(73)

SREC, Policy Paths A & B:
Overarching Supply Curve Granularity

- The Foundation of the Path A & B Models is a Supply Curve comprised of 612 Production Blocks
- Each Production Block is a Unique Combination of:
  - Project Type (i.e., Residential Roofmount, Medium Landfill, CSS) – 22 Types
  - Utility District (i.e., Munis, NGRID, Nstar BeCO, etc.) – 6 Districts
  - Ownership Type (i.e.. Third Party Owned, Host Owned, Public Owned) - 3 Types
  - Cost Type (High, Medium, Low Cost) - 3 Types (only 6 projects type are further disaggregated by Cost Type)
- MW Installs, MWh Production, Technical Potential, CoE, and Incentives are tracked on a quarterly basis for each of the 612 Production Blocks.

(74)

I. POLICY PATHS A & B

MODELING APPROACH AND ASSUMPTIONS

(75)

Path A & B: Aggregate Program Targets

- Overall Annual Program Targets were set to achieve 2500 MW (including SREC-I & SREC-II) by 2500, with less than 2% increase in targets annually
  - This was done to minimize installation volatility.
- For Capped Scenarios, Initial 2017 Program Aggregate Targets were set at 120 MW, increasing by 2.5 MW, to a Target of 140 MW in 2025.
- For Uncapped Scenarios, Initial 2017 Program Aggregate Targets were set at 120 MW, increasing by 2.0 MW, to a Target of 136 MW in 2025.
  - Increase was set lower than Capped because more MW were installed under SREC-II Uncapped than SREC-II Capped.
- Total Program Targets were set to exceed 2500 MW by 8.8 MW (Capped) and 13 MW (Uncapped) to Ensure 2500 MW target was Hit
  - Overbuild in final quarter of installations was pro-rated to ensure that C/B analysis only modeled costs/benefits for 2500 MW of installations.

(76)

Path A & B: Sector Specific Program Targets

- For Path A and Path B Uncapped, the following Target % were set for each Sector:
  - Sector A Small-Residential: 13.33%
  - Sector A Small-Non-Residential: 1%
  - Of the total % not devoted to Small Residential & Small Non-Residential:
    - Sector A Large: 25%
    - Sector B: 25%
    - Sector C: 25%
    - Sector D (MG): 25%
- For Path A and Path B Uncapped, the following Target % were set for each Sector:
  - Sector A Small-Residential: 13.33%
  - Sector A Small-Non-Residential: 1%
  - Of the total % not devoted to Small Residential & Small Non-Residential:
    - Sector A Large: 10%
    - Sector B: 30%
    - Sector C: 30%
    - Sector MG: 30%
- Sector A Large, Path A & Path B is set at 10% under the Capped Scenario because, as CSS and VNM LIH cannot exist in a NM Capped Scenario, the Sector lacks Resource Potential to hit a 25% Target; the 15% that was not allocated to Sector A Large was evenly distributed between Sector B, C and MG.
- Sector Specific Program Targets directly effect total installs by Path A Large Sectors, as Quarterly Base Solicitation Targets are set equal to one-fourth of Annual Targets.
- Sector Specific Program Targets affect Path A & Path B DBI/PBI & EPBI as Initially Block sizes are set at ½ of the annual 2017 target.

(77)

Path A & B: Starting Resource Potential –Utility Distribution

- Projected 2015-2016 Annual Installs were used as a Base Starting Resource Potential each Project Type (i.e., Residential Roofmount, CSS, Medium MG)
- Base Starting Resource Potential was then divided between each utility for each project type based on whether the Project was Residential, Non-Residential, Land Use Constrained, or Landfill/Brownfield:
  - Residential: Base Starting Potential was divided between each utility based on total % of Residential Customers (i.e. if Residential Roofmount project type has 10 MW of Base Starting Potential, and 10% of Residential customers are in Utility X, Utility X's -Residential Roofmount has 1MW of Resource Potential)
  - Non-Residential: Base Starting Potential was divided between each utility based on total % of Non-Residential Customers
  - Land-Use Constrained: Base Starting Potential was divided between each utility based on a weighting of open space potential in the utility district (2x Weight), and % Non-Residential Customers in each utility (1x Weight).
    - Open Space Potential is an analytically derived metric based on: 1.) Total Acreage in each Utility; and 2.) Population density in each utility.
  - Landfill/Brownfield: Base Starting Potential was divided between each utility based on a weighting of open space potential in the utility district (1x Weight), and % Non-Residential Customers in each utility (2x Weight).

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Path A & B: Starting Resource Potential –Ownership/Cost Distribution

- After dividing Resource Potential between each utility, Resource Potential was then divided between project ownership types (Host Owned, Third Party Owned, Public Owned) based on 2015-2016 SREC-II projections.
  - E.G., Residential Roofmount had roughly a 51-49% relative split between Third Party Owned and Host Owned Projects, thus 51% of technical potential was distributed to 3PO, and 49% to HO projects.

- Finally, after dividing Resource Potential between utilities and ownership type, Resource potential was further divided based on whether the Project Type was segmented by High/Medium/Low Cost.
  - 50% to Medium Cost
  - 25% to Low Cost
  - 25% to High Cost
  - If a project type was not segmented by Cost, naturally no division occurred.

(79)

Path A & B: Ongoing Resource Potential & Growth Rates

- Production Block Resource Potential in each Sector grow at a fixed rate annually, which is equal to MW installed in the previous year multiplied by a Growth Factor.
  - e.g., If a Production Block installs 20 MW in a year, and the Growth factor is 105%, the Production Block will have a technical potential of 21 MW in the subsequent year.
  - Growth Rates set conservatively at 105%-116% for all Sectors.
- Growth/Resource Potential forecasted on an annual basis; as the Model runs quarterly, annual Resource Potential was divided by four (4) to establish quarterly potential.
- Resurrection Rates: In the event a modeled Production Block installs no MW in a year, but Cost ofentry declines to such a degree that said Block could install in subsequent year, Resource Potential is set at ½ of Starting Potential (i.e., Resource Potential in 2017) for installs in the subsequent.

(80)

Path A Large: Competitive Solicitation, Modeling Assumptions

- Solicitations modeled to take place every Quarter.
- Base Quarterly Solicitation Targets equal to ¼ of Annual Sector Targets.
- "Price is Right" Type Solicitation Modeling: Each Quarter, Production Blocks are modeled to be successful until the cumulative MW including the next potential successful marginal Production Block's Resource Capacity is greater than Solicitation Targets (i.e. closest without going over).
  - This means that each solicitation, some % of the MW Target is not fulfilled (unless by chance, Cumulative MW installed for the Marginal Production Block exactly equals the Target);
  - The % of MW target not hit is rolled to the next solicitation as a Remainder.
- Further, a **10% Failure Rate** (i.e. 10% of selected projects fail to reach commercial operation) is assumed; all successful Production Blocks are prorated by 10%, and "Failed MW" are rolled into a solicitation exactly one year in the future.
- Quarterly Targets are equal to: Base Quarterly Target + Remainder & Failed MW carried to that solicitation.
- The combination of Remainder MW and Failure Rates means that MW solicited in each quarterly solicitation increase at a higher rate than initially set Annual Target percentages, and, likewise, that less MW is installed in early years than targeted.
- No Failure Rate assumed in 2025, so that the Model can hit Program Targets.

(81)

Path A Large: Competitive Solicitation, Incentive Assumptions

- Assumed that Production Blocks cannot bid below the value of Electric/NM Rates received from their utility.
- Production Block modeled to bid a Combined Incentive Bid (equal to their needed PBI Incentive + Levelized 15-yr Value of Electric/NM Rates).
- It is assumed that Bidders will strategically bid in such a way as to converge their bids with the marginal bid; thus, in calculating incentives for C/B Analysis, the **calculated Combined Incentive Bid for a successful bidder is equal to the average of the Marginal Bid and the bidders Cost of Entry Bid**.
- PBI Incentive are calculated for C/B analysis by netting out the 15-yr Levelized Value of Electric/NM Rates from the Combined Incentive Bid.

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Path A & B: DBI/PBI, Modeling Assumptions

- Modeled on a Quarterly basis;
- Initial DBI Block sizes set equal to ½ of 2017 Annual Targets;
- All Production Blocks across a Sector compete for the same DBI/PBI Block (however, DBI/PBI incentives vary by utility)
- Model only allows at most two (2) DBI Blocks to fill per quarter;
  - Therefore, total MW that can be installed in a quarter is equal to: total MW remaining in a DBI Block that was partially filled in the previous quarter + the DBI Block Size.
- Model functions by looking at the PBI Incentive Level that each utility is offering, and allowing a Production Block to install in that quarter if PBI is greater than Cost of Entry.

(83)

Path A& B: DBI/PBI, Incentive Assumptions

- Initial DBI/PBI Incentives are set for utility in each Sector, in reference to an Initial Benchmark "Combined Incentive."
- Initial Combined Incentives are calculated by:
  - Selecting a Benchmark Production Block (e.g., Commercial Solar Canopy-NGIRD-Third Party Owned);
  - Determining the Levelized 15-yr Value of Electric/NM Rates for the Benchmark Production Block;
  - Adding this Levelized 15-yr Rate Value to an Optimized DBI/PBI Starting $/MWh incentive (Optimization process discussed in subsequent slide);
- DBI/PBI incentives are then set for each utility by netting out the Levelized 15-yr Rate Value specific to the comparable Benchmark Production Block in that utility from the Combined Incentive.
  - E.g., if the Benchmark Production Block is Commercial Solar Canopy-NGIRD-Third Party Owned, the Levelized 15-yr Rate Value for Commercial Solar Canopy-WMECO-Third Party Owned is netted from the Combined Incentive to determine the initial WMECO DBI/PBI .
- All Utility DBI/PBI incentives in a sector decline by the same specific fixed $/MWh rate:
  - Fixed $/MWh decline used because a % based decline will never "zero-out"
  - Further, analysis showed that program volatility can be better managed with $/MWh than % based DBI/PBI declines.

(84)

Path B: DBI/EPBI Modeling/Incentive Assumptions

- Path B DBI/EPBI was modeled using exactly the same process as DBI/PBI, with the exception that DBI/PBI and Initial Combined Incentives were calculated in $/kW rather than $/MWh; **and**
- The Levelized 15-yr Value of Electric/NM Rates was calculated by discounting the 15-year calculated PBI using the Production Block's weighted average cost of capital (WACC) as a discount rate, rather than Target Equity IRR.

(85)

Path A & B: DBI/PBI & EPBI Incentive Optimization Process

- **Setting DBI/PBI Incentives involves a balancing of several factors:** 2017 install Rates, and level of industry constriction versus 2016; level, constant growth versus volatile growth; setting minimum incentive levels to achieve 2025 targets at lowest cost.
- Because of this, Initial DBI/PBI/EPBI incentives (and decline rates) were set to meet the following policy objectives as closely as possible:
  - 2017 annual installs in each sector being as close to 2017 targets as possible;
  - Sectors hitting their targets (and the Program Hitting 2500 MW) as close to QT. 4, 2025 as possible;
  - Minimize volatility in annual installs from 2017-2025;
  - Incentive levels as low as possible, while still meeting the above objectives, to minimize costs;
- There is more than one solution set (i.e. Initial DBI/PBI or EPBI Incentive Levels **and** $/MWh or $/kW decline rate) that can meet the above parameters;
  - However, more than 100 combinations were tested for each Sector (under each Policy Path and Scenario), and any parallel solution set would be, at best, only marginally better.
- As Path A, Large does not use an open-enrollment system, and incentives are set by bidding rather than centrally planned, no optimization process was necessary.

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J. CALCULATION OF OTHER COST & BENEFIT COMPONENTS

MISC. OTHER ASSUMPTIONS

(87)

‘Parametric Analysis’ Components

- Where data availability is limited or estimate would require extensive analysis infeasible within scope/timeline, we will make a parametric assumption
  - Example: “x% of cost item retained in-state”
- Consulting team will make an ‘anchor’ estimate
  - Based on brief literature, review, TF member input, or team judgment.
- When parametric assumption is applied to a model result (i.e. in $ or $/yr), a 10% sensitivity is possible.
  - Example: if anchor parameter is 50%, result will also be calculated as 60%
  - The sensitivity to changes of 10% from the key assumption is easily scaled to give magnitude of sensitivity over a broad range
- When parametric assumption is applied as an input to a complex model, analysis of sensitivities are beyond scope.

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Parametric Values Assumptions:
Base Case Values used for All Presented Results; Sensitivity #s used for Sensitivity Analyses

		Parameter	Selected Parameter	Selected Value	Base	Sensitivity	Description
System Installed Costs	CB1.1	A	Base	42%	42%	52.0%*	% of System Installed Cost Expenditures Retained In-State
Ongoing O&M + Insurance Costs	CB1.2	A	Base	64%	64%	74.0%*	% of Ongoing O&M & Insurance Cost Expenditures Retained In-State
ROI (Aggregate Return to Debt & Equity)	CB1.5	A	Base	30%	30%	40.0%*	% of Return to Debt & Equity Investors Retained In-State
Federal Incentives (ITC)	CB1.7a	A	Base	15%	15%	25.0%*	% of Federal ITC retained in-state (assume same as CB1.1-A)
Avoided Generation Capacity Costs	CB5.3	A	Base	28.8%	28.8%	38.8%*	Fraction of solar PV monetizing its value in the FCM; [56 MW of DR PV with CSOs + 85 MW of PV with included on the load side for the FCA9 ICR calculation] divided by 489 MW total forecast = 28.8%
Avoided Trans. Investment - Remote Wind	CB6.1	A	Base	$ 27.50	$ 27.50	$ 35.00	$/MWh Incremental TX cost for Northern New England wind avoided by supplanting need for Class I wind with MA Solar PV
Avoided Trans. Investment - Remote Wind	CB6.1	B	Base	55%	55%	80%	% of incremental TX cost for Northern New England Wind assumed allocated to load
Avoided Transmission Investment - Local	CB6.2	A	Base	30%	30.0%	40%*	% of load on feeders with growth
Avoided Transmission Investment - Local	CB6.2	B	Base	80%	80.0%	90%*	Scalar Adjustment Factor for technical issues (reduces gross value to account for a variety of technical issues preventing solar PV from avoiding investment deferral
Avoided Distribution Investment	CB6.3	A	Base	30%	30.0%	40%*	% of load on feeders with growth
Avoided Distribution Investment	CB6.3	B	Base	50%	50.0%	60%*	Scalar Adjustment Factor for technical issues (reduces gross value to account for a variety of technical issues preventing solar PV from avoiding investment deferral
Avoided Distribution Investment	CB6.3	C	Base	50%	50.0%	60%*	Scalar derating factor applied to distribution level energy losses avoided by solar PV, to reflect that the D investment is at varying locations often close to load, while aggregate D losses measured at D system injection; also reflects that some of literature review sources were already loss adjusted

(89)

System Installed Costs CB1.1

System Installed Costs Retained in State (Inputs)

	Residential			Small Commercial (Roof-top)			Small Commercial (Ground-mount)		
	Cost ($/kW)	% of Total Cost*	% Local Share	Cost ($/kW)	% of Total Cost*	% Local Share	Cost ($/kW)	% of Total Cost*	% Local Share
System Installation Costs									
Installation Costs									
Materials & Equipment									
Mounting (rails, clamps, fittings, etc.)	$168.10	3.4%	50%	$165.52	3.4%	40%	$90.71	3.4%	25%
Modules	$1,637.13	33.4%	0%	$1,612.05	33.4%	0%	$883.43	33.4%	0%
Electrical (wire, connectors, breakers, etc.)	$108.16	2.2%	50%	$106.51	2.2%	40%	$58.37	2.2%	25%
Inverter	$243.37	5.0%	50%	$239.64	5.0%	40%	$131.33	5.0%	25%
Labor									
Installation	$350.68	7.2%	95%	$345.30	7.2%	90%	$189.23	7.2%	70%
Other Costs									
Permitting	$651.64	13.3%	95%	$641.66	13.3%	95%	$351.64	13.3%	95%
Other Costs	$293.02	6.0%	63%	$288.53	6.0%	56%	$158.12	6.0%	56%
Business Overhead	$1,446.19	29.5%	63%	$1,424.04	29.5%	56%	$780.40	29.5%	56%
Sales Tax (Materials & Equipment Purchases)	$0.00	0%	0%	$0.00	0%	0%	$0.00	0%	0%
Total	$4,896.00	100.0%	47%	$4,821.00	100.0%	43%	$2,642.00	100.0%	40%

- % of Total Cost comes from NREL JEDI model default data for Massachusetts
- % Local Share developed from DOER 2013 Task 4 Consultant Report: "*Comparative Regional Economic Impacts of Solar Ownership/Financing Alternatives*" and supplemental research
- Used approx. weighted average of 42%. Based on analysis of annual weighted avg. blend of res, commercial rooftop and ground mount over time. #s were not highly sensitive to evolving blend, varying between 41% and 43%.

(90)

Ongoing O&M + Insurance Costs | CB1.2

System O&M Costs Retained in State (Inputs)

	Residential			Small Commercial (Roof-top)			Small Commercial (Ground-mount)		
	Cost ($/kW)	% of Total Cost*	% Local Share	Cost ($/kW)	% of Total Cost*	% Local Share	Cost ($/kW)	% of Total Cost*	% Local Share
Ongoing O&M Costs									
Labor									
Technicians	$11.46	54.6%	100%	$11.46	54.6%	90%	$8.73	54.6%	90%
Materials and Services									
Materials & Equipment	$9.55	45.5%	50%	$9.55	45.5%	40%	$7.28	45.5%	25%
Services	$0.00	0.0%	100%	$0.00	0.0%	56%	$0.00	0.0%	58%
Sales Tax (Materials & Equipment Purchases)	$0.00	0%	0%	$0.00	0%	0%	$0.00	0%	0%
Total	$21.00	100.0%	77%	$21.00	100.0%	67%	$16.00	100.0%	60%

- % of Total Cost comes from NREL JEDI model default data for Massachusetts
- % Local Share developed from DOER 2013 Task 4 Consultant Report: "*Comparative Regional Economic Impacts of Solar Ownership/Financing Alternatives*" and supplemental research
- Used 64%. Based on analysis of annual weighted avg. blend of res, commercial rooftop and ground mount over time. #s were not highly sensitive to evolving blend, varying between 63% and 68%

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Wholesale Market Price Impacts - Energy | CB5.1

Wholesale Market Price Impacts

- Wholesale energy market price effects are not in perpetuity
  - Effect of installation in year X assumed to dissipate based on energy DRIPE 2014 dissipation schedule from AESC 2013
- Wholesale energy market price effects only impact purchases from spot market or short-term transactions influenced by spot market. Energy transacted under multi-year energy hedges are not impacted
  - Effect of installation in year X assumed to phase in according to 2014 energy DRIPE hedged energy schedule from AESC 2013

Table 4. Energy Market Effect Adjustments

Production Year(s)	Dissipation %	Load Subject to Solar Market Effects
1	13%	18%
2	18%	72%
3	21%	81%
4	28%	90%
5	34%	90%
6	47%	90%
7	59%	91%
8	70%	91%
9	81%	91%
10	91%	92%
11-end of study period	100%	92%

(92)

Solar Policy Incr. Admin. & Transaction Costs | CB2.4

Estimating EDC Incremental Admin Costs for Policy Paths A & B

- Assumed all EDC labor costs were incremental (whether or not EDC would have sought additional rate recover for these types of costs as core vs. incremental staff in the past)
- Cost estimates by SEA based SEA interpretation of interviews with EDC procurement staff
  - Results not reviewed or endorsed by EDCs
- Categories:
  - One-tome Setup Costs, New Policies (Staffing: EDC staff, legal); systems; tariff design, approvals, training)
    - Small: 2 FTEs, split 75% in 2016, 25% in 2017
    - Large: 2 FTEs, split 75% in 2016, 25% in 2017
    - Same for Paths A & B
  - Solicitation Costs (thru 2025) – Policy Path A (large) only
    - Including core staff, assume 25% of $500K. Assume this is per solicitation round based on LREC/ZREC 1 round/yr. If move to 3 rounds per year, assume some scale economies ==> assume 2.5x the cost of one solicitation
    - Escalate at 4%/yr
  - Ongoing Admin. Costs from 2017 on (Ongoing admin costs (meter reading, hand holding, accounting, payments, recovery filings… (applying from startup to completion, thru 2050)
    - Assume 1.25 FTEs initially for small and 2 for large
    - Costs assumed to escalate annually by 20% of increase in target procurement volume to reflect some increase in labor costs with increased transcaction volume but strong scale economies
  - Transaction Costs for reselling RECs on a $/MWh (Broker Fees Associated with the Sale of RECs if performed through a broker)
    - Assume $1/MWh, applying to 50% of all distribution load (reflecting 1 – today's basic service %)
    - Note: Under SREC, Assume EDCs only purchase for own needs, don't need to resell; SREC Policy 'transactional friction" modeled as part of SREC market mdoel as $2.50 per SREC purchased by LSEs outside of small quantity of direct hedge transactions entered into with generators up-front to support financing
    - Note: corresponding market participant costs for SREC policies embedded in SREC market model, captured there
- Utility staff Average FTE cost used in model: $162,500 fully-loaded, based on input from 2 EDCs

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Solar Policy Incr. Admin. & Transaction Costs | CB2.4

Policy Path A additional developer overhead due to the need to sell both winning and losing bids:
Cust Aq. Cost * (sales/contract under solicitation – sale/contract under open program)

Commercial PV Customer Acquisition Cost ($/kW) (from NREL studies)			
Project Type	Med/Small	Med/Small	Large
Project Size	Not Specified	<250 kW	>250kW
Note	2010 Median	2012 Median	2012 Median
System Design	$0.10	$0.04	$0.01
Marketing/Advertising	$0.01	-	-
Other	$0.08	$0.09	$0.02
Total	$0.19	$0.13	$0.03

Assume $0.05/W as approx. fleet wtd. Avg.

*

Assume 2.5 bids/winning bid

➔ $0.05/W*(2.5-1) = $0.075/W

		# of Projects								
		Round 1			Round 2			Round 3		
		Total	Accepted	Ratio	Total	Accepted	Ratio	Total	Accepted	Ratio
Large ZREC	CL&P	140	21	6.67	52	19	2.74	78	32	2.44
	UI	22	6	3.67	12	4	3.00	8	8	1.00
	Total	162	27	6.00	64	23	2.78	86	40	2.15
Medium ZREC	CL&P	113	47	2.40	157	70	2.24	113	95	1.19
	UI	37	13	2.85	35	24	1.46	50	27	1.85
	Total	150	60	2.50	192	94	2.04	163	122	1.34

		Capacity (MW)								
		Round 1			Round 2			Round 3		
		Total	Accepted	Ratio	Total	Accepted	Ratio	Total	Accepted	Ratio
Large ZREC	CL&P	94.3	12.2	7.73	34.2	12.2	2.80	65.3	27.6	2.37
	UI	12.1	2.6	4.65	7.2	2.4	3.00	5.9	5.9	1.00
	Total	106.4	14.8	7.19	41.4	14.6	2.84	71.2	33.5	2.13
Medium ZREC	CL&P	21.5	8.8	2.44	30.2	14.2	2.13	24.5	18.1	1.35
	UI	7.1	2.5	2.84	6.4	4.4	1.45	9.7	5.1	1.90
	Total	28.6	11.3	2.53	36.6	18.6	1.97	34.2	23.2	1.47

MA Income Taxes	CB1.6.b	Federal Income Taxes	CB1.7b

Estimate of Taxable Discounts & Lease Revenue

Used for estimating income tax impact of these benefits on NOPs

% of Discount Payments Assumed Taxable

Scenario	2015	2020	2025
SREC Capped-1600	35%	80%	80%
SREC Uncapped-1600	35%	80%	80%
SREC Capped-2500	35%	80%	80%
Policy A Capped-1600	35%	80%	80%
Policy A Capped-2500	35%	80%	80%
Policy A Uncapped-1600	35%	80%	80%
Policy A Uncapped-2500	35%	35%	35%
Policy B Capped-1600	35%	80%	80%
Policy B Capped-2500	35%	80%	80%
Policy B Uncapped-1600	35%	80%	80%
Policy B Uncapped-2500	35%	35%	35%

% of Lease Payments Assumed Taxable

Scenario	2015	2020	2025
SREC Capped-1600	75%	80%	80%
SREC Uncapped-1600	75%	80%	80%
SREC Capped-2500	75%	80%	80%
Policy A Capped-1600	75%	80%	80%
Policy A Capped-2500	75%	80%	80%
Policy A Uncapped-1600	75%	80%	80%
Policy A Uncapped-2500	75%	75%	75%
Policy B Capped-1600	75%	80%	80%
Policy B Capped-2500	75%	80%	80%
Policy B Uncapped-1600	75%	80%	80%
Policy B Uncapped-2500	75%	75%	75%

Assumptions made based on SEA side-analysis to estimate evolving mix of taxable and non-taxable lease and PPA/NMC off-takers

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Task Report 3: Appendix B

Appendix B:

Task 3 - Analysis of Costs and Benefits: Detailed Cost and Benefit Result Tables

Massachusetts Net Metering and Solar Task Force

PEREGRINE ENERGY GROUP

Sustainable Energy Advantage, LLC

MEISTER CONSULTANTS GROUP

La Capra Associates

NOP Costs and Benefits – SREC Capped

Benefits

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

Costs

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

(2)

NOP Costs and Benefits – SREC Uncapped

Benefits

C/B Component ↓	CB Code	1600 MW NPV Benefits (Million $)	1600 MW NPV $/MWh Benefits
Lease Payments	CB1.3	$ 223.4	$ 5.1
PILOTs / Property Taxes	CB1.4	$ 160.7	$ 3.7
Generation Value of On-site Generation	CB3.1	$ 94.1	$ 2.2
Transmission Value of On-site Generation	CB3.2	$ 15.7	$ 0.4
Distribution Value of On-site Generation	CB3.3	$ 37.9	$ 0.9
Other Retail Bill Components (Trans., EE, RE)	CB3.4	$ 6.6	$ 0.2
Offsetting On-site Usage	CB4.1	$ 9.1	$ 0.2
Virtual NM	CB4.2	$ 525.0	$ 12.1
Total		**$ 1,072.5**	**$ 24.6**

Costs

C/B Component ↓	CB Code	1600 MW NPV Costs (Million $)	1600 MW NPV $/MWh Costs
MA Income Taxes	CB1.6.b	$ 53.0	$ 1.2
Federal Income Taxes	CB1.7b	$ 231.9	$ 5.3
Total		**$ 284.9**	**$ 6.5**

(3)

NOP Costs and Benefits – Policy A Capped

Benefits

C/B Component ↓	CB Code	2500 MW NPV Benefits (Million $)	2500 MW NPV $/MWh Benefits	1600 MW NPV Benefits (Million $)	1600 MW NPV $/MWh Benefits
Lease Payments	CB1.3	$ 304.3	$ 4.3	$ 222.7	$ 5.0
PILOTs / Property Taxes	CB1.4	$ 204.3	$ 2.9	$ 156.8	$ 3.5
Generation Value of On-site Generation	CB3.1	$ 167.8	$ 2.4	$ 104.8	$ 2.3
Transmission Value of On-site Generation	CB3.2	$ 24.9	$ 0.4	$ 17.3	$ 0.4
Distribution Value of On-site Generation	CB3.3	$ 63.9	$ 0.9	$ 42.3	$ 0.9
Other Retail Bill Components (Trans., EE, RE)	CB3.4	$ 10.8	$ 0.2	$ 7.3	$ 0.2
Offsetting On-site Usage	CB4.1	$ 10.2	$ 0.1	$ 9.0	$ 0.2
Virtual NM	CB4.2	$ 453.1	$ 6.4	$ 453.1	$ 10.1
Total		**$ 1,239.3**	**$ 17.6**	**$ 1,013.3**	**$ 22.7**

Costs

C/B Component ↓	CB Code	2500 MW NPV Costs (Million $)	2500 MW NPV$/MWh Costs	1600 MW NPV Costs (Million $)	1600 MW NPV $/MWh Costs
MA Income Taxes	CB1.6.b	$ 63.3	$ 0.9	$ 51.9	$ 1.2
Federal Income Taxes	CB1.7b	$ 277.0	$ 3.9	$ 227.1	$ 5.1
Total		**$ 340.4**	**$ 4.8**	**$ 279.0**	**$ 6.2**

(4)

NOP Costs and Benefits – Policy A Uncapped

Benefits

C/B Component ↓	CB Code	2500 MW NPV Benefits (Million $)	2500 MW NPV $/MWh Benefits	1600 MW NPV Benefits (Million $)	1600 MW NPV $/MWh Benefits
Lease Payments	CB1.3	$ 203.8	$ 2.9	$ 198.1	$ 4.4
PILOTs / Property Taxes	CB1.4	$ 146.8	$ 2.1	$ 142.9	$ 3.2
Generation Value of On-site Generation	CB3.1	$ 134.7	$ 1.9	$ 97.4	$ 2.2
Transmission Value of On-site Generation	CB3.2	$ 19.8	$ 0.3	$ 16.2	$ 0.4
Distribution Value of On-site Generation	CB3.3	$ 48.0	$ 0.7	$ 39.3	$ 0.9
Other Retail Bill Components (Trans., EE, RE)	CB3.4	$ 9.1	$ 0.1	$ 6.8	$ 0.2
Offsetting On-site Usage	CB4.1	$ 11.9	$ 0.2	$ 9.3	$ 0.2
Virtual NM	CB4.2	$ 659.1	$ 9.4	$ 497.8	$ 11.1
Total		**$ 1,233.2**	**$ 17.5**	**$ 1,008.0**	**$ 22.6**

Costs

C/B Component ↓	CB Code	2500 MW NPV Costs (Million $)	2500 MW NPV$/MWh Costs	1600 MW NPV Costs (Million $)	1600 MW NPV $/MWh Costs
MA Income Taxes	CB1.6.b	$ 36.6	$ 0.5	$ 49.0	$ 1.1
Federal Income Taxes	CB1.7b	$ 160.2	$ 2.3	$ 214.2	$ 4.8
Total		**$ 196.8**	**$ 2.8**	**$ 263.2**	**$ 5.9**

(5)

NOP Costs and Benefits – Policy B Capped

Benefits

C/B Component ↓	CB Code	2500 MW NPV Benefits (Million $)	2500 MW NPV $/MWh Benefits	1600 MW NPV Benefits (Million $)	1600 MW NPV $/MWh Benefits
Lease Payments	CB1.3	$ 299.1	$ 4.2	$ 222.4	$ 5.0
PILOTs / Property Taxes	CB1.4	$ 204.3	$ 2.9	$ 157.5	$ 3.5
Generation Value of On-site Generation	CB3.1	$ 160.1	$ 2.3	$ 102.2	$ 2.3
Transmission Value of On-site Generation	CB3.2	$ 25.9	$ 0.4	$ 17.0	$ 0.4
Distribution Value of On-site Generation	CB3.3	$ 66.6	$ 0.9	$ 41.9	$ 0.9
Other Retail Bill Components (Trans., EE, RE)	CB3.4	$ 10.3	$ 0.1	$ 7.1	$ 0.2
Offsetting On-site Usage	CB4.1	$ 11.8	$ 0.2	$ 9.2	$ 0.2
Virtual NM	CB4.2	$ 453.1	$ 6.4	$ 453.1	$ 10.1
Total		**$ 1,231.0**	**$ 17.5**	**$ 1,010.3**	**$ 22.6**

Costs

C/B Component ↓	CB Code	2500 MW NPV Costs (Million $)	2500 MW NPV$/MWh Costs	1600 MW NPV Costs (Million $)	1600 MW NPV $/MWh Costs
MA Income Taxes	CB1.6.b	$ 62.8	$ 0.9	$ 51.7	$ 1.2
Federal Income Taxes	CB1.7b	$ 274.7	$ 3.9	$ 226.0	$ 5.1
Total		**$ 337.5**	**$ 4.8**	**$ 277.7**	**$ 6.2**

(6)

NOP Costs and Benefits – Policy B Uncapped

Benefits

C/B Component ↓	CB Code	2500 MW NPV Benefits (Million $)	2500 MW NPV $/MWh Benefits	1600 MW NPV Benefits (Million $)	1600 MW NPV $/MWh Benefits
Lease Payments	CB1.3	$ 299.1	$ 4.3	$ 222.0	$ 5.0
PILOTs / Property Taxes	CB1.4	$ 213.2	$ 3.0	$ 159.5	$ 3.6
Generation Value of On-site Generation	CB3.1	$ 132.3	$ 1.9	$ 97.1	$ 2.2
Transmission Value of On-site Generation	CB3.2	$ 21.6	$ 0.3	$ 16.1	$ 0.4
Distribution Value of On-site Generation	CB3.3	$ 52.3	$ 0.7	$ 39.2	$ 0.9
Other Retail Bill Components (Trans., EE, RE)	CB3.4	$ 8.8	$ 0.1	$ 6.8	$ 0.2
Offsetting On-site Usage	CB4.1	$ 13.7	$ 0.2	$ 9.6	$ 0.2
Virtual NM	CB4.2	$ 775.5	$ 11.0	$ 520.4	$ 11.7
Total		**$ 1,516.6**	**$ 21.6**	**$ 1,070.8**	**$ 24.0**

Costs

C/B Component ↓	CB Code	2500 MW NPV Costs (Million $)	2500 MW NPV$/MWh Costs	1600 MW NPV Costs (Million $)	1600 MW NPV $/MWh Costs
MA Income Taxes	CB1.6.b	$ 45.7	$ 0.7	$ 53.0	$ 1.2
Federal Income Taxes	CB1.7b	$ 199.9	$ 2.8	$ 232.0	$ 5.2
Total		**$ 245.7**	**$ 3.5**	**$ 285.0**	**$ 6.4**

(7)

CG Costs and Benefits – SREC Capped

Benefits

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

Costs

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

(8)

CG Costs and Benefits – SREC Uncapped

Benefits

C/B Component ↓	CB Code	1600 MW NPV Benefits (Million $)	1600 MW NPV $/MWh Benefits
ROI (Aggregate Return to Debt & Equity)	CB1.5	$ -	$ -
MA Residential RE Tax Credit	CB1.6.a	$ 42.4	$ 1.0
Federal Incentives (ITC)	CB1.7a	$ 1,258.1	$ 28.9
Direct Incentives (e.g., SRECs)	CB2.1	$ 3,526.7	$ 81.0
Generation Value of On-site Generation	CB3.1	$ 766.0	$ 17.6
Transmission Value of On-site Generation	CB3.2	$ 130.9	$ 3.0
Distribution Value of On-site Generation	CB3.3	$ 320.6	$ 7.4
Other Retail Bill Components (Trans., EE, RE)	CB3.4	$ 51.3	$ 1.2
Offsetting On-site Usage	CB4.1	$ 103.1	$ 2.4
Virtual NM	CB4.2	$ 2,891.5	$ 66.4
Wholesale Market Sales	CB4.3	$ -	$ -
Avoided Generation Capacity Costs	CB5.3	$ 77.9	$ 1.8
Total		**$ 9,168.5**	**$ 210.6**

Costs

C/B Component ↓	CB Code	1600 MW NPV Costs (Million $)	1600 MW NPV $/MWh Costs
System Installed Costs	CB1.1	$ 5,136.5	$ 118.0
Ongoing O&M + Insurance Costs	CB1.2	$ 986.7	$ 22.7
Lease Payments	CB1.3	$ 223.4	$ 5.1
PILOTs / Property Taxes	CB1.4	$ 160.7	$ 3.7
MA Income Taxes	CB1.6.b	$ 23.0	$ 0.5
Federal Income Taxes	CB1.7b	$ 100.8	$ 2.3
Solar Policy Incr. Admin. & Transaction Costs	CB2.4	$ -	$ -
Total		**$ 6,631.2**	**$ 152.3**

(9)

CG Costs and Benefits – Policy A Capped

Benefits

C/B Component ↓	CB Code	2500 MW NPV Benefits (Million $)	2500 MW NPV $/MWh Benefits	1600 MW NPV Benefits (Million $)	1600 MW NPV $/MWh Benefits
ROI (Aggregate Return to Debt & Equity)	CB1.5	$ -	$ -	$ -	$ -
MA Residential RE Tax Credit	CB1.6.a	$ 59.8	$ 0.8	$ 43.8	$ 1.0
Federal Incentives (ITC)	CB1.7a	$ 1,335.4	$ 19.0	$ 1,251.3	$ 28.0
Direct Incentives (e.g., SRECs)	CB2.1	$ 4,342.9	$ 61.7	$ 3,592.3	$ 80.4
Generation Value of On-site Generation	CB3.1	$ 1,462.9	$ 20.8	$ 836.4	$ 18.7
Transmission Value of On-site Generation	CB3.2	$ 213.3	$ 3.0	$ 138.6	$ 3.1
Distribution Value of On-site Generation	CB3.3	$ 551.3	$ 7.8	$ 343.0	$ 7.7
Other Retail Bill Components (Trans., EE, RE)	CB3.4	$ 90.3	$ 1.3	$ 55.9	$ 1.3
Offsetting On-site Usage	CB4.1	$ 114.2	$ 1.6	$ 94.9	$ 2.1
Virtual NM	CB4.2	$ 2,409.7	$ 34.2	$ 2,409.7	$ 53.9
Wholesale Market Sales	CB4.3	$ 841.1	$ 11.9	$ 226.7	$ 5.1
Avoided Generation Capacity Costs	CB5.3	$ 119.0	$ 1.7	$ 77.8	$ 1.7
Total		**$ 11,540.0**	**$ 163.8**	**$ 9,070.2**	**$ 202.9**

Costs

C/B Component ↓	CB Code	2500 MW NPV Costs (Million $)	2500 MW NPV$/MWh Costs	1600 MW NPV Costs (Million $)	1600 MW NPV $/MWh Costs
System Installed Costs	CB1.1	$ 6,267.7	$ 89.0	$ 5,094.3	$ 114.0
Ongoing O&M + Insurance Costs	CB1.2	$ 1,270.7	$ 18.0	$ 949.5	$ 21.2
Lease Payments	CB1.3	$ 304.3	$ 4.3	$ 222.7	$ 5.0
PILOTs / Property Taxes	CB1.4	$ 204.3	$ 2.9	$ 156.8	$ 3.5
MA Income Taxes	CB1.6.b	$ 222.2	$ 3.2	$ 123.1	$ 2.8
Federal Income Taxes	CB1.7b	$ 972.0	$ 13.8	$ 538.5	$ 12.0
Solar Policy Incr. Admin. & Transaction Costs	CB2.4	$ 71.2	$ 1.0	$ 17.9	$ 0.4
Total		**$ 9,312.3**	**$ 132.2**	**$ 7,102.7**	**$ 158.9**

(10)

CG Costs and Benefits – Policy A Uncapped

Benefits

C/B Component ↓	CB Code	2500 MW NPV Benefits (Million $)	2500 MW NPV $/MWh Benefits	1600 MW NPV Benefits (Million $)	1600 MW NPV $/MWh Benefits
ROI (Aggregate Return to Debt & Equity)	CB1.5	$ -	$ -	$ -	$ -
MA Residential RE Tax Credit	CB1.6.a	$ 58.8	$ 0.8	$ 43.2	$ 1.0
Federal Incentives (ITC)	CB1.7a	$ 1,337.1	$ 19.0	$ 1,256.4	$ 28.1
Direct Incentives (e.g., SRECs)	CB2.1	$ 3,830.3	$ 54.5	$ 3,446.4	$ 77.2
Generation Value of On-site Generation	CB3.1	$ 1,258.6	$ 17.9	$ 786.3	$ 17.6
Transmission Value of On-site Generation	CB3.2	$ 182.1	$ 2.6	$ 131.8	$ 3.0
Distribution Value of On-site Generation	CB3.3	$ 452.2	$ 6.4	$ 321.1	$ 7.2
Other Retail Bill Components (Trans., EE, RE)	CB3.4	$ 81.2	$ 1.2	$ 53.2	$ 1.2
Offsetting On-site Usage	CB4.1	$ 133.3	$ 1.9	$ 99.0	$ 2.2
Virtual NM	CB4.2	$ 3,513.1	$ 50.0	$ 2,687.3	$ 60.2
Wholesale Market Sales	CB4.3	$ -	$ -	$ -	$ -
Avoided Generation Capacity Costs	CB5.3	$ 119.2	$ 1.7	$ 77.8	$ 1.7
Total		**$ 10,966.0**	**$ 156.0**	**$ 8,902.6**	**$ 199.3**

Costs

C/B Component ↓	CB Code	2500 MW NPV Costs (Million $)	2500 MW NPV$/MWh Costs	1600 MW NPV Costs (Million $)	1600 MW NPV $/MWh Costs
System Installed Costs	CB1.1	$ 6,236.8	$ 88.7	$ 5,085.4	$ 113.9
Ongoing O&M + Insurance Costs	CB1.2	$ 879.3	$ 12.5	$ 859.7	$ 19.2
Lease Payments	CB1.3	$ 203.8	$ 2.9	$ 198.1	$ 4.4
PILOTs / Property Taxes	CB1.4	$ 146.8	$ 2.1	$ 142.9	$ 3.2
MA Income Taxes	CB1.6.b	$ 211.0	$ 3.0	$ 85.7	$ 1.9
Federal Income Taxes	CB1.7b	$ 922.9	$ 13.1	$ 375.1	$ 8.4
Solar Policy Incr. Admin. & Transaction Costs	CB2.4	$ 69.9	$ 1.0	$ 16.4	$ 0.4
Total		**$ 8,670.5**	**$ 123.3**	**$ 6,763.3**	**$ 151.4**

(11)

CG Costs and Benefits – Policy B Capped

Benefits

C/B Component ↓	CB Code	2500 MW NPV Benefits (Million $)	2500 MW NPV $/MWh Benefits	1600 MW NPV Benefits (Million $)	1600 MW NPV $/MWh Benefits
ROI (Aggregate Return to Debt & Equity)	CB1.5	$ -	$ -	$ -	$ -
MA Residential RE Tax Credit	CB1.6.a	$ 60.0	$ 0.9	$ 43.8	$ 1.0
Federal Incentives (ITC)	CB1.7a	$ 1,325.7	$ 18.8	$ 1,248.6	$ 27.9
Direct Incentives (e.g., SRECs)	CB2.1	$ 4,173.2	$ 59.2	$ 3,577.5	$ 80.0
Generation Value of On-site Generation	CB3.1	$ 1,468.3	$ 20.8	$ 827.0	$ 18.5
Transmission Value of On-site Generation	CB3.2	$ 228.2	$ 3.2	$ 138.9	$ 3.1
Distribution Value of On-site Generation	CB3.3	$ 575.3	$ 8.2	$ 344.1	$ 7.7
Other Retail Bill Components (Trans., EE, RE)	CB3.4	$ 91.2	$ 1.3	$ 55.4	$ 1.2
Offsetting On-site Usage	CB4.1	$ 131.0	$ 1.9	$ 99.5	$ 2.2
Virtual NM	CB4.2	$ 2,409.7	$ 34.2	$ 2,409.7	$ 53.9
Wholesale Market Sales	CB4.3	$ 838.6	$ 11.9	$ 234.9	$ 5.3
Avoided Generation Capacity Costs	CB5.3	$ 119.2	$ 1.7	$ 77.8	$ 1.7
Total		**$ 11,420.4**	**$ 162.1**	**$ 9,057.2**	**$ 202.6**

Costs

C/B Component ↓	CB Code	2500 MW NPV Costs (Million $)	2500 MW NPV$/MWh Costs	1600 MW NPV Costs (Million $)	1600 MW NPV $/MWh Costs
System Installed Costs	CB1.1	$ 6,224.5	$ 88.4	$ 5,086.3	$ 113.8
Ongoing O&M + Insurance Costs	CB1.2	$ 1,315.2	$ 18.7	$ 964.8	$ 21.6
Lease Payments	CB1.3	$ 299.1	$ 4.2	$ 222.4	$ 5.0
PILOTs / Property Taxes	CB1.4	$ 204.3	$ 2.9	$ 157.5	$ 3.5
MA Income Taxes	CB1.6.b	$ 188.9	$ 2.7	$ 118.0	$ 2.6
Federal Income Taxes	CB1.7b	$ 826.5	$ 11.7	$ 510.3	$ 11.4
Solar Policy Incr. Admin. & Transaction Costs	CB2.4	$ -	$ -	$ -	$ -
Total		**$ 9,058.4**	**$ 128.6**	**$ 7,059.2**	**$ 157.9**

(12)

CG Costs and Benefits – Policy B Uncapped

Benefits

C/B Component ↓	CB Code	2500 MW NPV Benefits (Million $)	2500 MW NPV $/MWh Benefits	1600 MW NPV Benefits (Million $)	1600 MW NPV $/MWh Benefits
ROI (Aggregate Return to Debt & Equity)	CB1.5	$ -	$ -	$ -	$ -
MA Residential RE Tax Credit	CB1.6.a	$ 59.1	$ 0.8	$ 43.4	$ 1.0
Federal Incentives (ITC)	CB1.7a	$ 1,334.5	$ 19.0	$ 1,255.7	$ 28.1
Direct Incentives (e.g., SRECs)	CB2.1	$ 3,418.6	$ 48.6	$ 3,496.4	$ 78.3
Generation Value of On-site Generation	CB3.1	$ 1,277.5	$ 18.2	$ 788.0	$ 17.6
Transmission Value of On-site Generation	CB3.2	$ 203.9	$ 2.9	$ 132.3	$ 3.0
Distribution Value of On-site Generation	CB3.3	$ 492.0	$ 7.0	$ 323.5	$ 7.2
Other Retail Bill Components (Trans., EE, RE)	CB3.4	$ 81.3	$ 1.2	$ 53.2	$ 1.2
Offsetting On-site Usage	CB4.1	$ 159.0	$ 2.3	$ 105.2	$ 2.4
Virtual NM	CB4.2	$ 4,197.8	$ 59.7	$ 2,842.0	$ 63.6
Wholesale Market Sales	CB4.3	$ -	$ -	$ -	$ -
Avoided Generation Capacity Costs	CB5.3	$ 119.3	$ 1.7	$ 77.8	$ 1.7
Total		**$ 11,342.9**	**$ 161.3**	**$ 9,117.4**	**$ 204.2**

Costs

C/B Component ↓	CB Code	2500 MW NPV Costs (Million $)	2500 MW NPV$/MWh Costs	1600 MW NPV Costs (Million $)	1600 MW NPV $/MWh Costs
System Installed Costs	CB1.1	$ 6,274.2	$ 89.2	$ 5,095.9	$ 114.1
Ongoing O&M + Insurance Costs	CB1.2	$ 1,365.4	$ 19.4	$ 976.1	$ 21.9
Lease Payments	CB1.3	$ 299.1	$ 4.3	$ 222.0	$ 5.0
PILOTs / Property Taxes	CB1.4	$ 213.2	$ 3.0	$ 159.5	$ 3.6
MA Income Taxes	CB1.6.b	$ 236.6	$ 3.4	$ 91.9	$ 2.1
Federal Income Taxes	CB1.7b	$ 1,035.3	$ 14.7	$ 402.0	$ 9.0
Solar Policy Incr. Admin. & Transaction Costs	CB2.4	$ -	$ -	$ -	$ -
Total		**$ 9,423.8**	**$ 134.0**	**$ 6,947.4**	**$ 155.6**

(13)

NPR Costs and Benefits – SREC Capped

Benefits

C/B Component ↓	CB Code	2500 MW NPV Benefits (Million $)	2500 MW NPV $/MWh Benefits	1600 MW NPV Benefits (Million $)	1600 MW NPV $/MWh Benefits
MA Income Taxes	CB1.6.b	$ 146.9	$ 2.1	$ 150.1	$ 3.4
Displaced RPS Class I Compliance Costs	CB2.3	$ 1,471.6	$ 21.4	$ 921.8	$ 21.2
Generation Value of On-site Generation	CB3.1	$ 135.1	$ 2.0	$ 58.3	$ 1.3
Wholesale Market Sales	CB4.3	$ 3.9	$ 0.1	$ 2.7	$ 0.1
Wholesale Market Price Impacts - Energy	CB5.1	$ 54.4	$ 0.8	$ 64.4	$ 1.5
Avoided Generation Capacity Costs	CB5.3	$ 2,064.4	$ 30.0	$ 1,551.2	$ 35.6
Avoided Transmission Tariff Charges	CB5.5	$ 167.0	$ 2.4	$ 148.4	$ 3.4
Avoided Trans. Investment - Remote Wind	CB6.1	$ 181.8	$ 2.6	$ 112.5	$ 2.6
Avoided Transmission Investment - Local	CB6.2	$ 102.5	$ 1.5	$ 88.6	$ 2.0
Avoided Distribution Investment	CB6.3	$ 232.4	$ 3.4	$ 200.9	$ 4.6
Avoided Environmental Impacts	CB7.1	$ 710.8	$ 10.3	$ 660.0	$ 15.1
Total		**$ 5,270.6**	**$ 76.5**	**$ 3,958.8**	**$ 90.9**

Costs

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

(14)

NPR Costs and Benefits – SREC Uncapped

Benefits

C/B Component ↓	CB Code	1600 MW NPV Benefits	1600 MW NPV $/MWh Benefits
MA Income Taxes	CB1.6.b	$ 76.1	$ 1.7
Displaced RPS Class I Compliance Costs	CB2.3	$ 893.5	$ 20.5
Generation Value of On-site Generation	CB3.1	$ 48.0	$ 1.1
Wholesale Market Sales	CB4.3	$ -	$ -
Wholesale Market Price Impacts - Energy	CB5.1	$ 64.4	$ 1.5
Avoided Generation Capacity Costs	CB5.3	$ 1,549.3	$ 35.6
Avoided Transmission Tariff Charges	CB5.5	$ 148.2	$ 3.4
Avoided Trans. Investment - Remote Wind	CB6.1	$ 112.5	$ 2.6
Avoided Transmission Investment - Local	CB6.2	$ 88.5	$ 2.0
Avoided Distribution Investment	CB6.3	$ 200.6	$ 4.6
Avoided Environmental Impacts	CB7.1	$ 660.0	$ 15.2
Total		**$ 3,841.1**	**$ 88.2**

Costs

C/B Component ↓	CB Code	1600 MW NPV Costs (Million $)	1600 MW NPV $/MWh Costs
MA Residential RE Tax Credit	CB1.6.a	$ 42.4	$ 1.0
Direct Incentives (e.g., SRECs)	CB2.1	$ 3,812.7	$ 87.6
Other Solar Policy Compliance Costs (e.g. SACP)	CB2.2	$ 167.1	$ 3.8
Solar Policy Incr. Admin. & Transaction Costs	CB2.4	$ -	$ -
Transmission Value of On-site Generation	CB3.2	$ 146.6	$ 3.4
Distribution Value of On-site Generation	CB3.3	$ 358.6	$ 8.2
Other Retail Bill Components (Trans., EE, RE)	CB3.4	$ 52.2	$ 1.2
Offsetting On-site Usage	CB4.1	$ 60.3	$ 1.4
Virtual NM	CB4.2	$ 1,920.0	$ 44.1
Total		**$ 6,559.9**	**$ 150.7**

(15)

NPR Costs and Benefits – Policy A Capped

Benefits

C/B Component ↓	CB Code	2500 MW NPV Benefits (Million $)	2500 MW NPV $/MWh Benefits	1600 MW NPV Benefits (Million $)	1600 MW NPV $/MWh Benefits
MA Income Taxes	CB1.6.b	$ 285.5	$ 4.1	$ 175.0	$ 3.9
Displaced RPS Class I Compliance Costs	CB2.3	$ 1,552.6	$ 22.0	$ 961.4	$ 21.5
Generation Value of On-site Generation	CB3.1	$ 91.1	$ 1.3	$ 52.6	$ 1.2
Wholesale Market Sales	CB4.3	$ 47.0	$ 0.7	$ 12.7	$ 0.3
Wholesale Market Price Impacts - Energy	CB5.1	$ 54.4	$ 0.8	$ 64.4	$ 1.4
Avoided Generation Capacity Costs	CB5.3	$ 2,103.3	$ 29.9	$ 1,552.6	$ 34.7
Avoided Transmission Tariff Charges	CB5.5	$ 172.6	$ 2.4	$ 148.4	$ 3.3
Avoided Trans. Investment - Remote Wind	CB6.1	$ 181.8	$ 2.6	$ 112.5	$ 2.5
Avoided Transmission Investment - Local	CB6.2	$ 107.3	$ 1.5	$ 90.7	$ 2.0
Avoided Distribution Investment	CB6.3	$ 243.2	$ 3.5	$ 205.6	$ 4.6
Avoided Environmental Impacts	CB7.1	$ 710.8	$ 10.1	$ 660.0	$ 14.8
Total		**$ 5,549.5**	**$ 78.8**	**$ 4,035.8**	**$ 90.3**

Costs

C/B Component ↓	CB Code	2500 MW NPV Costs (Million $)	2500 MW NPV$/MWh Costs	1600 MW NPV Costs (Million $)	1600 MW NPV $/MWh Costs
MA Residential RE Tax Credit	CB1.6.a	$ 59.8	$ 0.8	$ 43.8	$ 1.0
Direct Incentives (e.g., SRECs)	CB2.1	$ 4,589.4	$ 65.2	$ 3,838.8	$ 85.9
Other Solar Policy Compliance Costs (e.g. SACP)	CB2.2	$ 191.1	$ 2.7	$ 191.1	$ 4.3
Solar Policy Incr. Admin. & Transaction Costs	CB2.4	$ 197.4	$ 2.8	$ 63.5	$ 1.4
Transmission Value of On-site Generation	CB3.2	$ 238.2	$ 3.4	$ 155.9	$ 3.5
Distribution Value of On-site Generation	CB3.3	$ 615.2	$ 8.7	$ 385.3	$ 8.6
Other Retail Bill Components (Trans., EE, RE)	CB3.4	$ 91.0	$ 1.3	$ 56.9	$ 1.3
Offsetting On-site Usage	CB4.1	$ 52.7	$ 0.7	$ 52.6	$ 1.2
Virtual NM	CB4.2	$ 1,668.0	$ 23.7	$ 1,663.5	$ 37.2
Total		**$ 7,702.9**	**$ 109.4**	**$ 6,451.3**	**$ 144.3**

(16)

NPR Costs and Benefits – Policy A Uncapped

Benefits

C/B Component ↓	CB Code	2500 MW NPV Benefits (Million $)	2500 MW NPV $/MWh Benefits	1600 MW NPV Benefits (Million $)	1600 MW NPV $/MWh Benefits
MA Income Taxes	CB1.6.b	$ 247.6	$ 3.5	$ 134.7	$ 3.0
Displaced RPS Class I Compliance Costs	CB2.3	$ 1,515.0	$ 21.5	$ 949.6	$ 21.3
Generation Value of On-site Generation	CB3.1	$ 77.8	$ 1.1	$ 49.4	$ 1.1
Wholesale Market Sales	CB4.3	$ -	$ -	$ -	$ -
Wholesale Market Price Impacts - Energy	CB5.1	$ 54.4	$ 0.8	$ 64.4	$ 1.4
Avoided Generation Capacity Costs	CB5.3	$ 2,101.6	$ 29.9	$ 1,551.2	$ 34.7
Avoided Transmission Tariff Charges	CB5.5	$ 172.3	$ 2.5	$ 148.2	$ 3.3
Avoided Trans. Investment - Remote Wind	CB6.1	$ 181.8	$ 2.6	$ 112.5	$ 2.5
Avoided Transmission Investment - Local	CB6.2	$ 106.9	$ 1.5	$ 90.5	$ 2.0
Avoided Distribution Investment	CB6.3	$ 242.3	$ 3.4	$ 205.1	$ 4.6
Avoided Environmental Impacts	CB7.1	$ 710.8	$ 10.1	$ 660.0	$ 14.8
Total		**$ 5,410.4**	**$ 76.9**	**$ 3,965.6**	**$ 88.8**

Costs

C/B Component ↓	CB Code	2500 MW NPV Costs (Million $)	2500 MW NPV$/MWh Costs	1600 MW NPV Costs (Million $)	1600 MW NPV $/MWh Costs
MA Residential RE Tax Credit	CB1.6.a	$ 58.8	$ 0.8	$ 43.2	$ 1.0
Direct Incentives (e.g., SRECs)	CB2.1	$ 4,080.3	$ 58.0	$ 3,696.4	$ 82.8
Other Solar Policy Compliance Costs (e.g. SACP)	CB2.2	$ 191.7	$ 2.7	$ 191.7	$ 4.3
Solar Policy Incr. Admin. & Transaction Costs	CB2.4	$ 108.1	$ 1.5	$ 61.8	$ 1.4
Transmission Value of On-site Generation	CB3.2	$ 201.9	$ 2.9	$ 148.0	$ 3.3
Distribution Value of On-site Generation	CB3.3	$ 500.3	$ 7.1	$ 360.4	$ 8.1
Other Retail Bill Components (Trans., EE, RE)	CB3.4	$ 81.3	$ 1.2	$ 54.1	$ 1.2
Offsetting On-site Usage	CB4.1	$ 52.9	$ 0.8	$ 52.7	$ 1.2
Virtual NM	CB4.2	$ 1,652.6	$ 23.5	$ 1,648.1	$ 36.9
Total		**$ 6,927.9**	**$ 98.5**	**$ 6,256.5**	**$ 140.1**

(17)

NPR Costs and Benefits – Policy B Capped

Benefits

C/B Component ↓	CB Code	2500 MW NPV Benefits (Million $)	2500 MW NPV $/MWh Benefits	1600 MW NPV Benefits (Million $)	1600 MW NPV $/MWh Benefits
MA Income Taxes	CB1.6.b	$ 251.7	$ 3.6	$ 169.7	$ 3.8
Displaced RPS Class I Compliance Costs	CB2.3	$ 1,555.7	$ 22.1	$ 960.7	$ 21.5
Generation Value of On-site Generation	CB3.1	$ 90.9	$ 1.3	$ 51.9	$ 1.2
Wholesale Market Sales	CB4.3	$ 46.8	$ 0.7	$ 13.1	$ 0.3
Wholesale Market Price Impacts - Energy	CB5.1	$ 54.4	$ 0.8	$ 64.4	$ 1.4
Avoided Generation Capacity Costs	CB5.3	$ 2,100.5	$ 29.8	$ 1,552.8	$ 34.7
Avoided Transmission Tariff Charges	CB5.5	$ 172.2	$ 2.4	$ 148.6	$ 3.3
Avoided Trans. Investment - Remote Wind	CB6.1	$ 181.8	$ 2.6	$ 112.5	$ 2.5
Avoided Transmission Investment - Local	CB6.2	$ 107.1	$ 1.5	$ 90.8	$ 2.0
Avoided Distribution Investment	CB6.3	$ 242.8	$ 3.4	$ 205.8	$ 4.6
Avoided Environmental Impacts	CB7.1	$ 710.8	$ 10.1	$ 660.0	$ 14.8
Total		**$ 5,514.8**	**$ 78.3**	**$ 4,030.4**	**$ 90.2**

Costs

C/B Component ↓	CB Code	2500 MW NPV Costs (Million $)	2500 MW NPV$/MWh Costs	1600 MW NPV Costs (Million $)	1600 MW NPV $/MWh Costs
MA Residential RE Tax Credit	CB1.6.a	$ 60.0	$ 0.9	$ 43.8	$ 1.0
Direct Incentives (e.g., SRECs)	CB2.1	$ 4,419.7	$ 62.7	$ 3,824.0	$ 85.5
Other Solar Policy Compliance Costs (e.g. SACP)	CB2.2	$ 191.1	$ 2.7	$ 191.1	$ 4.3
Solar Policy Incr. Admin. & Transaction Costs	CB2.4	$ 85.3	$ 1.2	$ 30.3	$ 0.7
Transmission Value of On-site Generation	CB3.2	$ 254.0	$ 3.6	$ 156.0	$ 3.5
Distribution Value of On-site Generation	CB3.3	$ 641.9	$ 9.1	$ 386.0	$ 8.6
Other Retail Bill Components (Trans., EE, RE)	CB3.4	$ 91.6	$ 1.3	$ 56.2	$ 1.3
Offsetting On-site Usage	CB4.1	$ 76.9	$ 1.1	$ 58.8	$ 1.3
Virtual NM	CB4.2	$ 1,668.0	$ 23.7	$ 1,663.5	$ 37.2
Total		**$ 7,488.5**	**$ 106.3**	**$ 6,409.7**	**$ 143.4**

(18)

NPR Costs and Benefits – Policy B Uncapped

Benefits

C/B Component ↓	CB Code	2500 MW NPV Benefits (Million $)	2500 MW NPV $/MWh Benefits	1600 MW NPV Benefits (Million $)	1600 MW NPV $/MWh Benefits
MA Income Taxes	CB1.6.b	$ 282.3	$ 4.0	$ 144.9	$ 3.2
Displaced RPS Class I Compliance Costs	CB2.3	$ 1,520.2	$ 21.6	$ 950.2	$ 21.3
Generation Value of On-site Generation	CB3.1	$ 78.7	$ 1.1	$ 49.4	$ 1.1
Wholesale Market Sales	CB4.3	$ -	$ -	$ -	$ -
Wholesale Market Price Impacts - Energy	CB5.1	$ 54.4	$ 0.8	$ 64.4	$ 1.4
Avoided Generation Capacity Costs	CB5.3	$ 2,100.7	$ 29.9	$ 1,551.3	$ 34.7
Avoided Transmission Tariff Charges	CB5.5	$ 172.2	$ 2.4	$ 148.3	$ 3.3
Avoided Trans. Investment - Remote Wind	CB6.1	$ 181.8	$ 2.6	$ 112.5	$ 2.5
Avoided Transmission Investment - Local	CB6.2	$ 106.9	$ 1.5	$ 90.6	$ 2.0
Avoided Distribution Investment	CB6.3	$ 242.2	$ 3.4	$ 205.3	$ 4.6
Avoided Environmental Impacts	CB7.1	$ 710.8	$ 10.1	$ 660.0	$ 14.8
Total		**$ 5,450.2**	**$ 77.5**	**$ 3,977.0**	**$ 89.1**

Costs

C/B Component ↓	CB Code	2500 MW NPV Costs (Million $)	2500 MW NPV$/MWh Costs	1600 MW NPV Costs (Million $)	1600 MW NPV $/MWh Costs
MA Residential RE Tax Credit	CB1.6.a	$ 59.1	$ 0.8	$ 43.4	$ 1.0
Direct Incentives (e.g., SRECs)	CB2.1	$ 3,668.6	$ 52.2	$ 3,599.4	$ 80.6
Other Solar Policy Compliance Costs (e.g. SACP)	CB2.2	$ 191.7	$ 2.7	$ 191.7	$ 4.3
Solar Policy Incr. Admin. & Transaction Costs	CB2.4	$ 85.1	$ 1.2	$ 30.2	$ 0.7
Transmission Value of On-site Generation	CB3.2	$ 225.6	$ 3.2	$ 148.4	$ 3.3
Distribution Value of On-site Generation	CB3.3	$ 544.3	$ 7.7	$ 362.7	$ 8.1
Other Retail Bill Components (Trans., EE, RE)	CB3.4	$ 81.5	$ 1.2	$ 54.0	$ 1.2
Offsetting On-site Usage	CB4.1	$ 90.0	$ 1.3	$ 61.4	$ 1.4
Virtual NM	CB4.2	$ 2,742.0	$ 39.0	$ 1,885.7	$ 42.2
Total		**$ 7,687.9**	**$ 109.3**	**$ 6,376.9**	**$ 142.8**

(19)

C@L Costs and Benefits – SREC Capped

Benefits

C/B Component ↓	CB Code	2500 MW NPV Benefits (Million $)	2500 MW NPV $/MWh Benefits	1600 MW NPV Benefits (Million $)	1600 MW NPV $/MWh Benefits
System Installed Costs	CB1.1	$ 2,812.6	$ 40.8	$ 2,176.9	$ 50.0
Ongoing O&M + Insurance Costs	CB1.2	$ 884.9	$ 12.8	$ 627.4	$ 14.4
Lease Payments	CB1.3	$ 228.2	$ 3.3	$ 209.0	$ 4.8
PILOTs / Property Taxes	CB1.4	$ 152.6	$ 2.2	$ 148.1	$ 3.4
ROI (Aggregate Return to Debt & Equity)	CB1.5	$ 1,120.9	$ 16.3	$ 667.7	$ 15.3
Federal Incentives (ITC)	CB1.7a	$ 195.7	$ 2.8	$ 188.8	$ 4.3
Displaced RPS Class I Compliance Costs	CB2.3	$ 1,471.6	$ 21.4	$ 921.8	$ 21.2
Generation Value of On-site Generation	CB3.1	$ 2,554.3	$ 37.1	$ 1,102.4	$ 25.3
Other Retail Bill Components (Trans., EE, RE)	CB3.4	$ 14.2	$ 0.2	$ 6.8	$ 0.2
Offsetting On-site Usage	CB4.1	$ 157.0	$ 2.3	$ 62.9	$ 1.4
Virtual NM	CB4.2	$ 1,282.7	$ 18.6	$ 1,287.7	$ 29.6
Wholesale Market Sales	CB4.3	$ 72.9	$ 1.1	$ 51.1	$ 1.2
Wholesale Market Price Impacts - Energy	CB5.1	$ 54.4	$ 0.8	$ 64.4	$ 1.5
Avoided Generation Capacity Costs	CB5.3	$ 2,184.5	$ 31.7	$ 1,629.0	$ 37.4
Avoided Transmission Tariff Charges	CB5.5	$ 167.0	$ 2.4	$ 148.4	$ 3.4
Avoided Trans. Investment - Remote Wind	CB6.1	$ 181.8	$ 2.6	$ 112.5	$ 2.6
Avoided Transmission Investment - Local	CB6.2	$ 102.5	$ 1.5	$ 88.6	$ 2.0
Avoided Distribution Investment	CB6.3	$ 232.4	$ 3.4	$ 200.9	$ 4.6
Avoided Environmental Impacts	CB7.1	$ 710.8	$ 10.3	$ 660.0	$ 15.1
Total		**$ 14,581.0**	**$ 211.7**	**$ 10,354.3**	**$ 237.6**

Costs

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

(20)

C@L Costs and Benefits – SREC Uncapped

Benefits

C/B Component ↓	CB Code	1600 MW NPV Benefits (Million $)	1600 MW NPV $/MWh Benefits
System Installed Costs	CB1.1	$ 2,157.3	$ 49.6
Ongoing O&M + Insurance Costs	CB1.2	$ 631.5	$ 14.5
Lease Payments	CB1.3	$ 223.4	$ 5.1
PILOTs / Property Taxes	CB1.4	$ 160.7	$ 3.7
ROI (Aggregate Return to Debt & Equity)	CB1.5	$ 761.2	$ 17.5
Federal Incentives (ITC)	CB1.7a	$ 188.7	$ 4.3
Displaced RPS Class I Compliance Costs	CB2.3	$ 893.5	$ 20.5
Generation Value of On-site Generation	CB3.1	$ 908.1	$ 20.9
Other Retail Bill Components (Trans., EE, RE)	CB3.4	$ 5.8	$ 0.1
Offsetting On-site Usage	CB4.1	$ 51.9	$ 1.2
Virtual NM	CB4.2	$ 1,496.4	$ 34.4
Wholesale Market Sales	CB4.3	$ -	$ -
Wholesale Market Price Impacts - Energy	CB5.1	$ 64.4	$ 1.5
Avoided Generation Capacity Costs	CB5.3	$ 1,627.1	$ 37.4
Avoided Transmission Tariff Charges	CB5.5	$ 148.2	$ 3.4
Avoided Trans. Investment - Remote Wind	CB6.1	$ 112.5	$ 2.6
Avoided Transmission Investment - Local	CB6.2		
Avoided Distribution Investment	CB6.3		
Avoided Environmental Impacts	CB7.1	$ 660.0	$ 15.2
Total		**$ 10,090.7**	**$ 231.8**

Costs

C/B Component ↓	CB Code	1600 MW NPV Costs (Million $)	1600 MW NPV $/MWh Costs
Federal Income Taxes	CB1.7b	$ 332.8	$ 7.6
Direct Incentives (e.g., SRECs)	CB2.1	$ 3,812.7	$ 87.6
Solar Policy Incr. Admin. & Transaction Costs	CB2.4	$ -	$ -
Total		**$ 4,145.4**	**$ 95.2**

(21)

C@L Costs and Benefits – Policy A Capped

Benefits

C/B Component ↓	CB Code	2500 MW NPV Benefits (Million $)	2500 MW NPV $/MWh Benefits	1600 MW NPV Benefits (Million $)	1600 MW NPV $/MWh Benefits
System Installed Costs	CB1.1	$ 2,632.4	$ 37.4	$ 2,139.6	$ 47.9
Ongoing O&M + Insurance Costs	CB1.2	$ 813.2	$ 11.5	$ 607.7	$ 13.6
Lease Payments	CB1.3	$ 304.3	$ 4.3	$ 222.7	$ 5.0
PILOTs / Property Taxes	CB1.4	$ 204.3	$ 2.9	$ 156.8	$ 3.5
ROI (Aggregate Return to Debt & Equity)	CB1.5	$ 668.3	$ 9.5	$ 590.2	$ 13.2
Federal Incentives (ITC)	CB1.7a	$ 200.3	$ 2.8	$ 187.7	$ 4.2
Displaced RPS Class I Compliance Costs	CB2.3	$ 1,552.6	$ 22.0	$ 961.4	$ 21.5
Generation Value of On-site Generation	CB3.1	$ 1,721.8	$ 24.4	$ 993.7	$ 22.2
Other Retail Bill Components (Trans., EE, RE)	CB3.4	$ 10.1	$ 0.1	$ 6.3	$ 0.1
Offsetting On-site Usage	CB4.1	$ 71.6	$ 1.0	$ 51.3	$ 1.1
Virtual NM	CB4.2	$ 1,194.8	$ 17.0	$ 1,199.3	$ 26.8
Wholesale Market Sales	CB4.3	$ 888.1	$ 12.6	$ 239.3	$ 5.4
Wholesale Market Price Impacts - Energy	CB5.1	$ 54.4	$ 0.8	$ 64.4	$ 1.4
Avoided Generation Capacity Costs	CB5.3	$ 2,222.3	$ 31.5	$ 1,630.4	$ 36.5
Avoided Transmission Tariff Charges	CB5.5	$ 172.6	$ 2.4	$ 148.4	$ 3.3
Avoided Trans. Investment - Remote Wind	CB6.1	$ 181.8	$ 2.6	$ 112.5	$ 2.5
Avoided Transmission Investment - Local	CB6.2	$ 107.3	$ 1.5	$ 90.7	$ 2.0
Avoided Distribution Investment	CB6.3	$ 243.2	$ 3.5	$ 205.6	$ 4.6
Avoided Environmental Impacts	CB7.1	$ 710.8	$ 10.1	$ 660.0	$ 14.8
Total		**$ 13,954.3**	**$ 198.1**	**$ 10,268.0**	**$ 229.7**

Costs

C/B Component ↓	CB Code	2500 MW NPV Costs (Million $)	2500 MW NPV$/MWh Costs	1600 MW NPV Costs (Million $)	1600 MW NPV $/MWh Costs
Federal Income Taxes	CB1.7b	$ 1,249.0	$ 17.7	$ 765.6	$ 17.1
Direct Incentives (e.g., SRECs)	CB2.1	$ 4,589.4	$ 65.2	$ 3,838.8	$ 85.9
Solar Policy Incr. Admin. & Transaction Costs	CB2.4	$ 197.4	$ 2.8	$ 63.5	$ 1.4
Total		**$ 6,035.8**	**$ 85.7**	**$ 4,667.9**	**$ 104.4**

(22)

C@L Costs and Benefits – Policy A Uncapped

Benefits

C/B Component ↓	CB Code	2500 MW NPV Benefits (Million $)	2500 MW NPV $/MWh Benefits	1600 MW NPV Benefits (Million $)	1600 MW NPV $/MWh Benefits
System Installed Costs	CB1.1	$ 2,619.5	$ 37.3	$ 2,135.9	$ 47.8
Ongoing O&M + Insurance Costs	CB1.2	$ 562.7	$ 8.0	$ 550.2	$ 12.3
Lease Payments	CB1.3	$ 203.8	$ 2.9	$ 198.1	$ 4.4
PILOTs / Property Taxes	CB1.4	$ 146.8	$ 2.1	$ 142.9	$ 3.2
ROI (Aggregate Return to Debt & Equity)	CB1.5	$ 688.7	$ 9.8	$ 641.8	$ 14.4
Federal Incentives (ITC)	CB1.7a	$ 200.6	$ 2.9	$ 188.5	$ 4.2
Displaced RPS Class I Compliance Costs	CB2.3	$ 1,515.0	$ 21.5	$ 949.6	$ 21.3
Generation Value of On-site Generation	CB3.1	$ 1,471.1	$ 20.9	$ 933.1	$ 20.9
Other Retail Bill Components (Trans., EE, RE)	CB3.4	$ 9.0	$ 0.1	$ 6.0	$ 0.1
Offsetting On-site Usage	CB4.1	$ 92.3	$ 1.3	$ 55.6	$ 1.2
Virtual NM	CB4.2	$ 2,519.7	$ 35.8	$ 1,537.1	$ 34.4
Wholesale Market Sales	CB4.3	$ -	$ -	$ -	$ -
Wholesale Market Price Impacts - Energy	CB5.1	$ 54.4	$ 0.8	$ 64.4	$ 1.4
Avoided Generation Capacity Costs	CB5.3	$ 2,220.7	$ 31.6	$ 1,629.0	$ 36.5
Avoided Transmission Tariff Charges	CB5.5	$ 172.3	$ 2.5	$ 148.2	$ 3.3
Avoided Trans. Investment - Remote Wind	CB6.1	$ 181.8	$ 2.6	$ 112.5	$ 2.5
Avoided Transmission Investment - Local	CB6.2	$ 106.9	$ 1.5	$ 90.5	$ 2.0
Avoided Distribution Investment	CB6.3	$ 242.3	$ 3.4	$ 205.1	$ 4.6
Avoided Environmental Impacts	CB7.1	$ 710.8	$ 10.1	$ 660.0	$ 14.8
Total		**$ 13,718.3**	**$ 195.1**	**$ 10,248.4**	**$ 229.5**

Costs

C/B Component ↓	CB Code	2500 MW NPV Costs (Million $)	2500 MW NPV$/MWh Costs	1600 MW NPV Costs (Million $)	1600 MW NPV $/MWh Costs
Federal Income Taxes	CB1.7b	$ 1,083.1	$ 15.4	$ 589.3	$ 13.2
Direct Incentives (e.g., SRECs)	CB2.1	$ 4,080.3	$ 58.0	$ 3,696.4	$ 82.8
Solar Policy Incr. Admin. & Transaction Costs	CB2.4	$ 108.1	$ 1.5	$ 61.8	$ 1.4
Total		**$ 5,271.6**	**$ 75.0**	**$ 4,347.5**	**$ 97.3**

(23)

C@L Costs and Benefits – Policy B Capped

Benefits

C/B Component ↓	CB Code	2500 MW NPV Benefits (Million $)	2500 MW NPV $/MWh Benefits	1600 MW NPV Benefits (Million $)	1600 MW NPV $/MWh Benefits
System Installed Costs	CB1.1	$ 2,614.3	$ 37.1	$ 2,136.2	$ 47.8
Ongoing O&M + Insurance Costs	CB1.2	$ 841.7	$ 11.9	$ 617.5	$ 13.8
Lease Payments	CB1.3	$ 299.1	$ 4.2	$ 222.4	$ 5.0
PILOTs / Property Taxes	CB1.4	$ 204.3	$ 2.9	$ 157.5	$ 3.5
ROI (Aggregate Return to Debt & Equity)	CB1.5	$ 708.6	$ 10.1	$ 599.4	$ 13.4
Federal Incentives (ITC)	CB1.7a	$ 198.9	$ 2.8	$ 187.3	$ 4.2
Displaced RPS Class I Compliance Costs	CB2.3	$ 1,555.7	$ 22.1	$ 960.7	$ 21.5
Generation Value of On-site Generation	CB3.1	$ 1,719.3	$ 24.4	$ 981.1	$ 21.9
Other Retail Bill Components (Trans., EE, RE)	CB3.4	$ 9.9	$ 0.1	$ 6.3	$ 0.1
Offsetting On-site Usage	CB4.1	$ 65.9	$ 0.9	$ 49.9	$ 1.1
Virtual NM	CB4.2	$ 1,194.8	$ 17.0	$ 1,199.3	$ 26.8
Wholesale Market Sales	CB4.3	$ 885.5	$ 12.6	$ 248.0	$ 5.5
Wholesale Market Price Impacts - Energy	CB5.1	$ 54.4	$ 0.8	$ 64.4	$ 1.4
Avoided Generation Capacity Costs	CB5.3	$ 2,219.7	$ 31.5	$ 1,630.6	$ 36.5
Avoided Transmission Tariff Charges	CB5.5	$ 172.2	$ 2.4	$ 148.6	$ 3.3
Avoided Trans. Investment - Remote Wind	CB6.1	$ 181.8	$ 2.6	$ 112.5	$ 2.5
Avoided Transmission Investment - Local	CB6.2	$ 107.1	$ 1.5	$ 90.8	$ 2.0
Avoided Distribution Investment	CB6.3	$ 242.8	$ 3.4	$ 205.8	$ 4.6
Avoided Environmental Impacts	CB7.1	$ 710.8	$ 10.1	$ 660.0	$ 14.8
Total		**$ 13,986.6**	**$ 198.6**	**$ 10,278.3**	**$ 229.9**

Costs

C/B Component ↓	CB Code	2500 MW NPV Costs (Million $)	2500 MW NPV$/MWh Costs	1600 MW NPV Costs (Million $)	1600 MW NPV $/MWh Costs
Federal Income Taxes	CB1.7b	$ 1,101.2	$ 15.6	$ 736.4	$ 16.5
Direct Incentives (e.g., SRECs)	CB2.1	$ 4,419.7	$ 62.7	$ 3,824.0	$ 85.5
Solar Policy Incr. Admin. & Transaction Costs	CB2.4	$ 85.3	$ 1.2	$ 30.3	$ 0.7
Total		**$ 5,606.2**	**$ 79.6**	**$ 4,590.7**	**$ 102.7**

(24)

C@L Costs and Benefits – Policy B Uncapped

Benefits

C/B Component ↓	CB Code	2500 MW NPV Benefits (Million $)	2500 MW NPV $/MWh Benefits	1600 MW NPV Benefits (Million $)	1600 MW NPV $/MWh Benefits
System Installed Costs	CB1.1	$ 2,635.2	$ 37.5	$ 2,140.3	$ 47.9
Ongoing O&M + Insurance Costs	CB1.2	$ 873.8	$ 12.4	$ 624.7	$ 14.0
Lease Payments	CB1.3	$ 299.1	$ 4.3	$ 222.0	$ 5.0
PILOTs / Property Taxes	CB1.4	$ 213.2	$ 3.0	$ 159.5	$ 3.6
ROI (Aggregate Return to Debt & Equity)	CB1.5	$ 575.7	$ 8.2	$ 651.0	$ 14.6
Federal Incentives (ITC)	CB1.7a	$ 200.2	$ 2.8	$ 188.4	$ 4.2
Displaced RPS Class I Compliance Costs	CB2.3	$ 1,520.2	$ 21.6	$ 950.2	$ 21.3
Generation Value of On-site Generation	CB3.1	$ 1,488.6	$ 21.2	$ 934.5	$ 20.9
Other Retail Bill Components (Trans., EE, RE)	CB3.4	$ 8.7	$ 0.1	$ 6.0	$ 0.1
Offsetting On-site Usage	CB4.1	$ 82.6	$ 1.2	$ 53.4	$ 1.2
Virtual NM	CB4.2	$ 2,231.3	$ 31.7	$ 1,476.7	$ 33.1
Wholesale Market Sales	CB4.3	$ -	$ -	$ -	$ -
Wholesale Market Price Impacts - Energy	CB5.1	$ 54.4	$ 0.8	$ 64.4	$ 1.4
Avoided Generation Capacity Costs	CB5.3	$ 2,220.0	$ 31.6	$ 1,629.2	$ 36.5
Avoided Transmission Tariff Charges	CB5.5	$ 172.2	$ 2.4	$ 148.3	$ 3.3
Avoided Trans. Investment - Remote Wind	CB6.1	$ 181.8	$ 2.6	$ 112.5	$ 2.5
Avoided Transmission Investment - Local	CB6.2	$ 106.9	$ 1.5	$ 90.6	$ 2.0
Avoided Distribution Investment	CB6.3	$ 242.2	$ 3.4	$ 205.3	$ 4.6
Avoided Environmental Impacts	CB7.1	$ 710.8	$ 10.1	$ 660.0	$ 14.8
Total		**$ 13,816.7**	**$ 196.5**	**$ 10,317.0**	**$ 231.0**

Costs

C/B Component ↓	CB Code	2500 MW NPV Costs (Million $)	2500 MW NPV$/MWh Costs	1600 MW NPV Costs (Million $)	1600 MW NPV $/MWh Costs
Federal Income Taxes	CB1.7b	$ 1,235.2	$ 17.6	$ 634.0	$ 14.2
Direct Incentives (e.g., SRECs)	CB2.1	$ 3,668.6	$ 52.2	$ 3,599.4	$ 80.6
Solar Policy Incr. Admin. & Transaction Costs	CB2.4	$ 85.1	$ 1.2	$ 30.2	$ 0.7
Total		**$ 4,989.0**	**$ 71.0**	**$ 4,263.7**	**$ 95.5**

(25)

Task 3 Report: Appendix C

Appendix C:

Task 3 - Analysis of Costs and Benefits: Policy Paths A & B Modeled Incentives

Massachusetts Net Metering and Solar Task Force

PEREGRINE ENERGY GROUP

Sustainable Energy Advantage, LLC

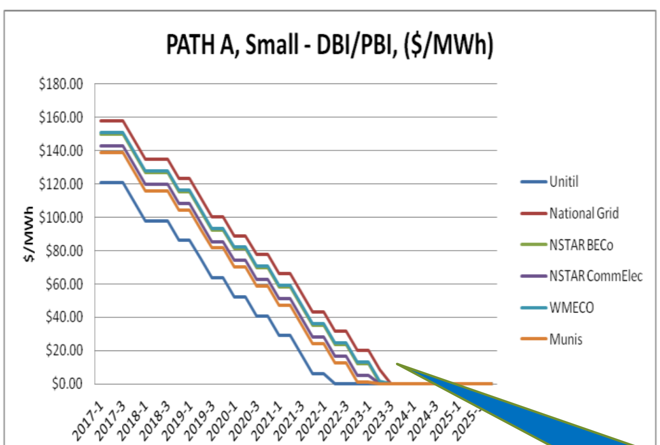
MEISTER CONSULTANTS GROUP

La Capra Associates

Policy Path A – Small Residential DBI/PBI

Slightly different DBI clearing speed function of slightly different starting tech. potential (**extremely** marginal effect)

Capped



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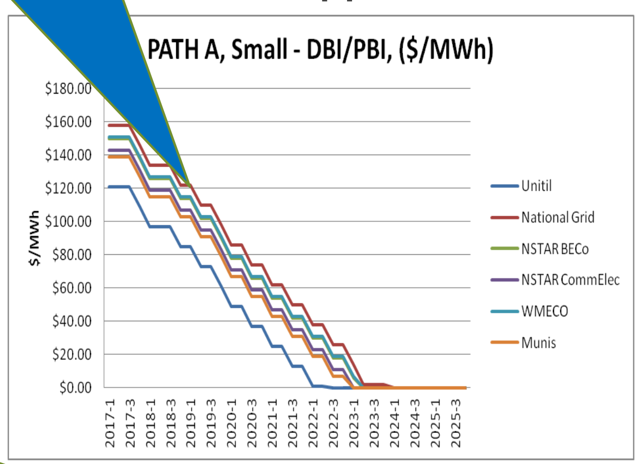


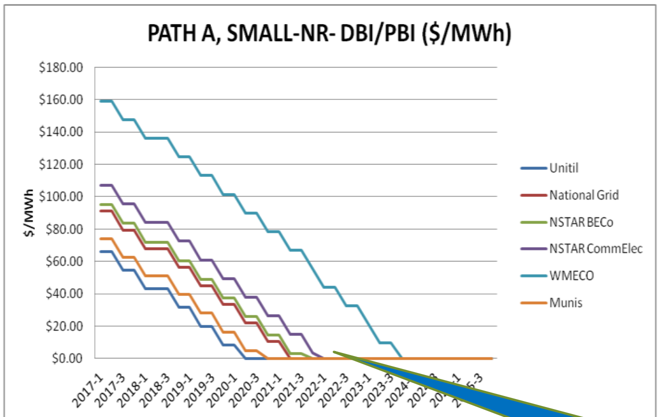
No PBI incentive needed Post-2023-Q2

(2)

Policy Path A – Small Non-Residential DBI/PBI

Slightly different DBI clearing speed function of slightly different starting tech. potential (**extremely** marginal effect)

Capped



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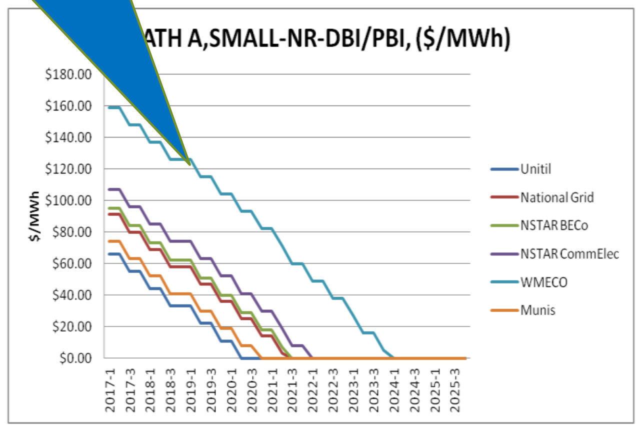


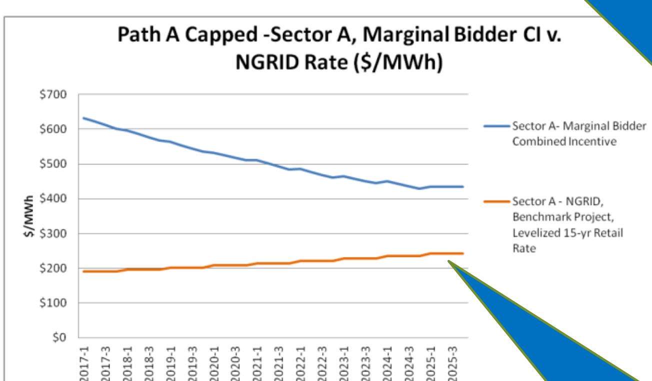
No PBI incentive needed Post-2021

(3)

Policy Path A – Large Competitive PBI – Sector A

When lines cross, Sector A which is dominated by CSS and VNM LIH do not need PBI with VNM.

Capped



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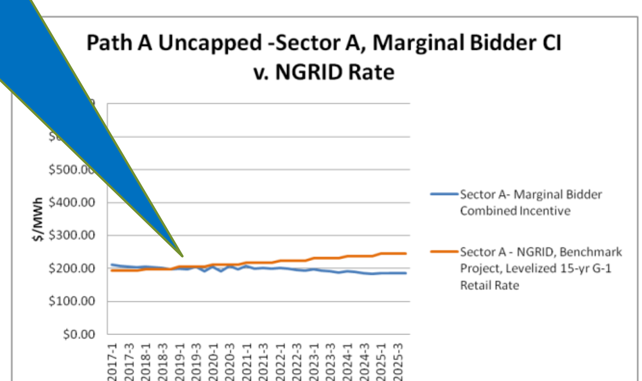


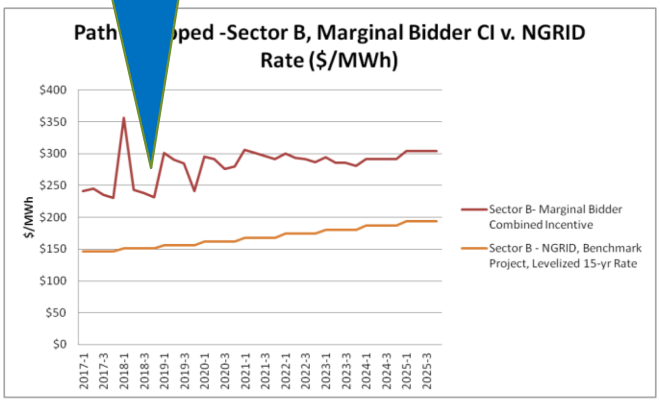
Marginal bid moves to convergence with rates, all Sectors.

(4)

Policy Path A – Large Competitive PBI – Sector B

Spikes reflect supply lumpiness and modeling method.

Capped



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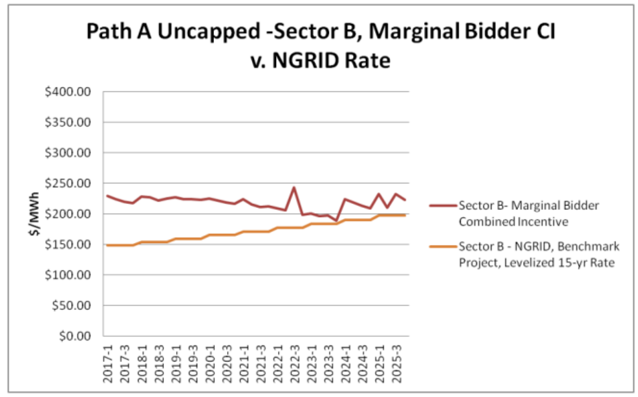
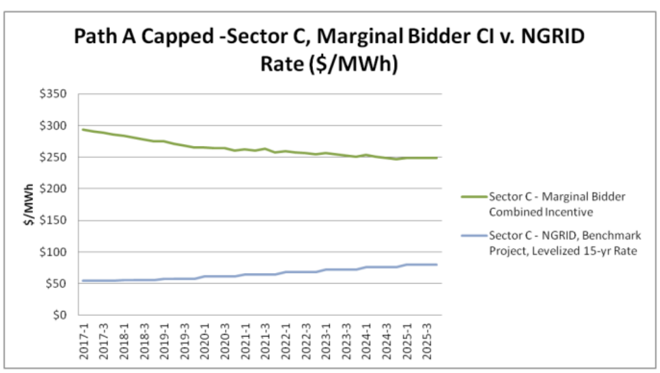


(5)

Policy Path A – Large Competitive PBI – Sector C

Higher Marginal Bid is function of modeling constraints, and not likely to be seen in practice. See Note.

Capped



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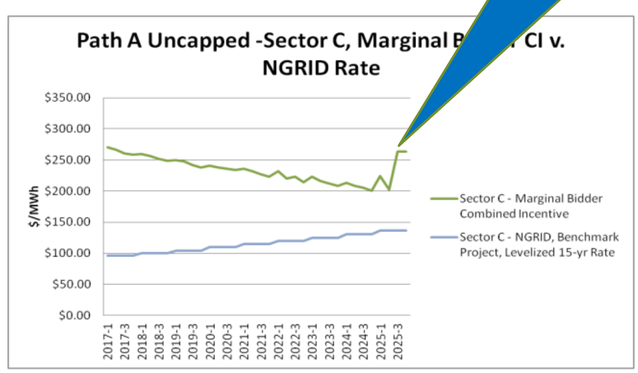
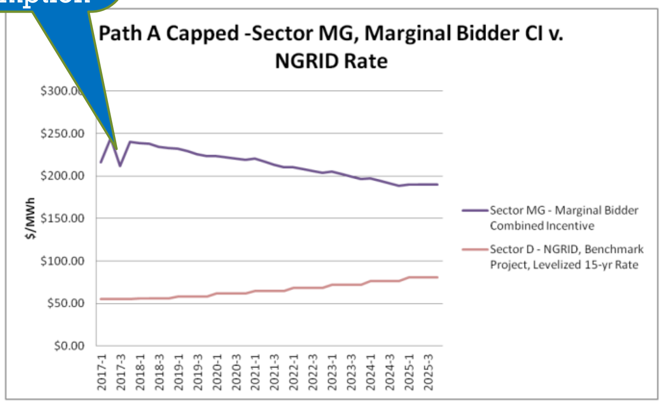


(6)

Policy Path A – Large Competitive PBI – Sector D

Spikes are reflective of "Price is Right" Modeling Assumption

Capped



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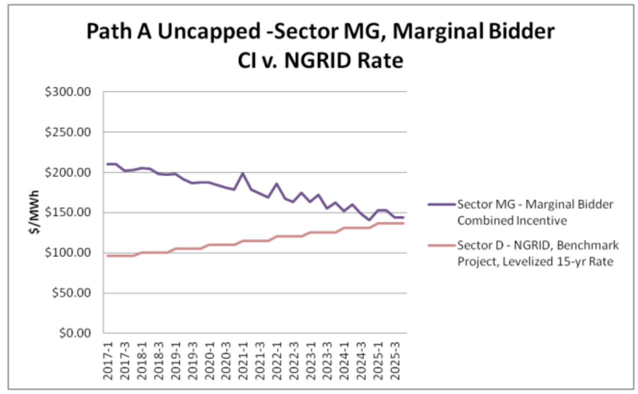
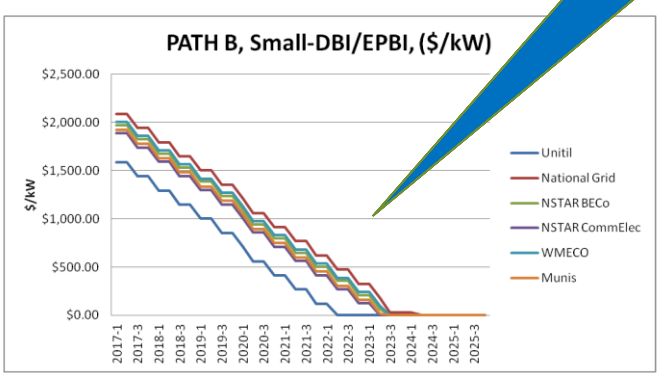


(7)

Policy Path B – Small Residential DBI/EPBI

Same for Both NM/ no NM

Capped



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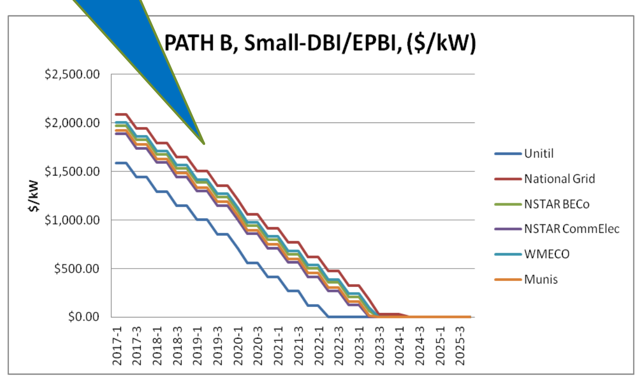
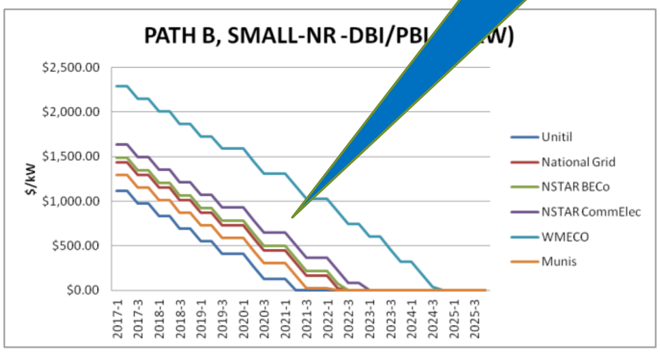


(8)

Policy Path B – Small Non-Residential DBI/EPBI

Same for Both NM/ no NM

Capped



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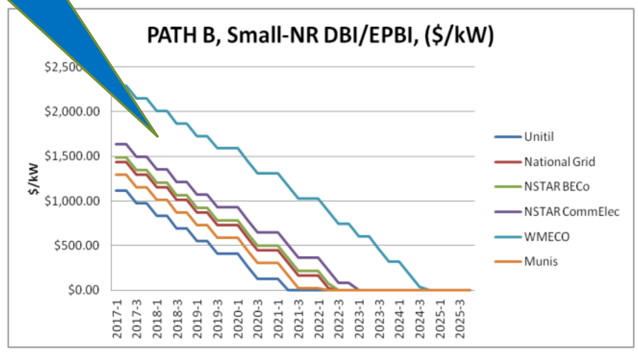
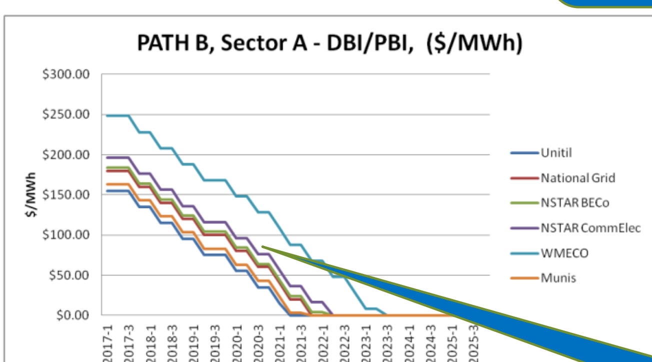


(9)

Policy Path B – Sector A DBI/PBI

By 2019, CSS and VNM LIH are no longer dependent on PBI at current NM levels

Capped



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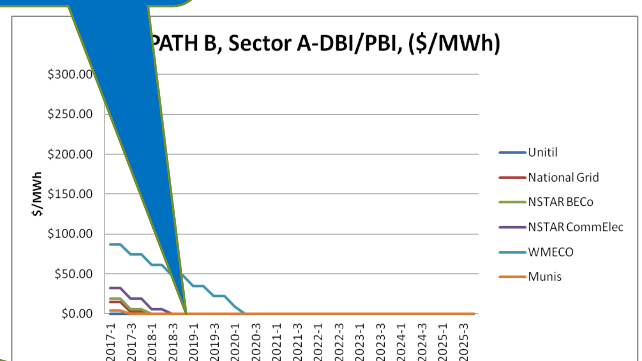
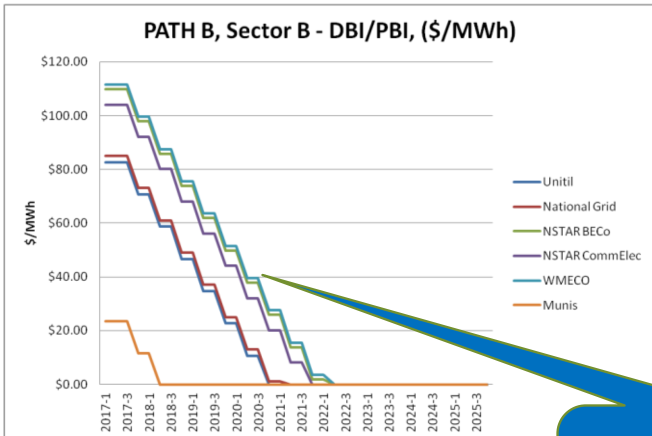


Comparative PBI levels must be viewed in context of lowered target (25%-10%)

(10)

Policy Path B – Sector B DBI/PBI

Capped



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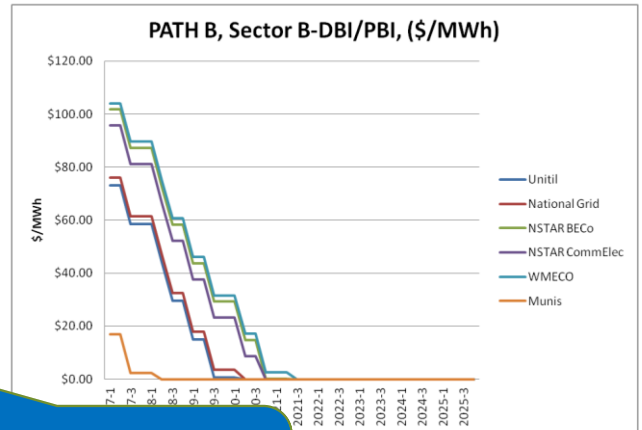


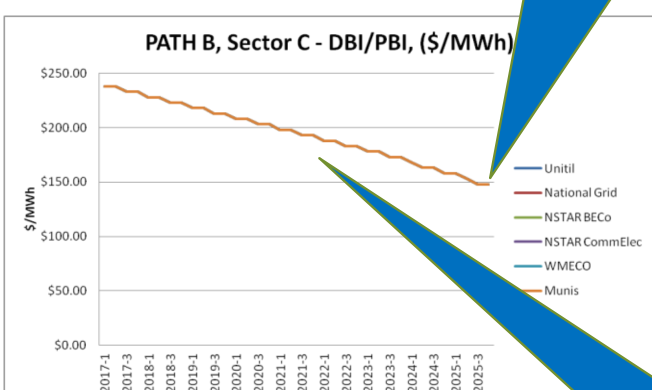
Comparative PBI levels must be viewed in context of raised target (25%-30%)

(11)

Policy Path B – Sector C DBI/PBI

Without NM retail rate is QF wholesale rate which is assumed equal across utility territories

Capped



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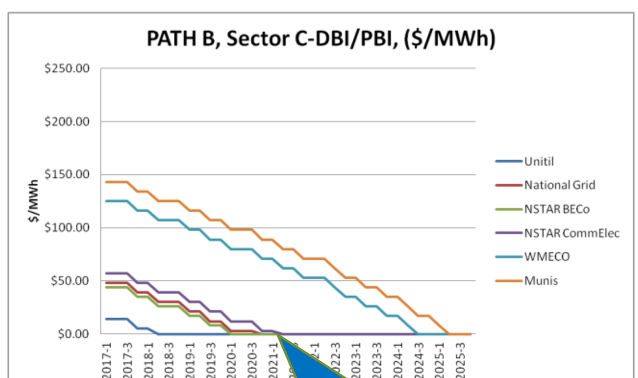


Comparative PBI levels must be viewed in context of raised target (25%-30%)

Most growth post-2020 is NM rate driven; signals no need for PBI after 2021

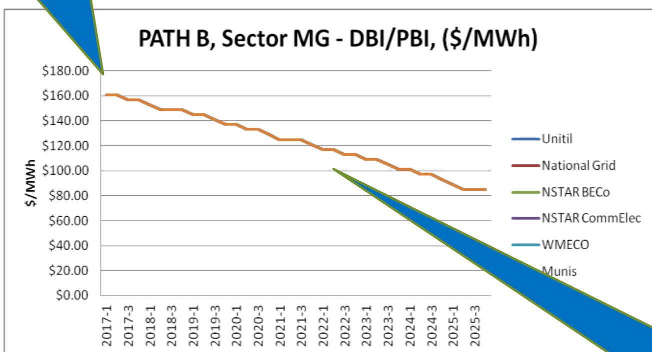
(12)

Policy Path B – Sector MG DBI/PBI

Without NM retail rate is QF wholesale rate which is assumed equal across utility territories

Most growth post 2021 is NM Rate Driven

Capped



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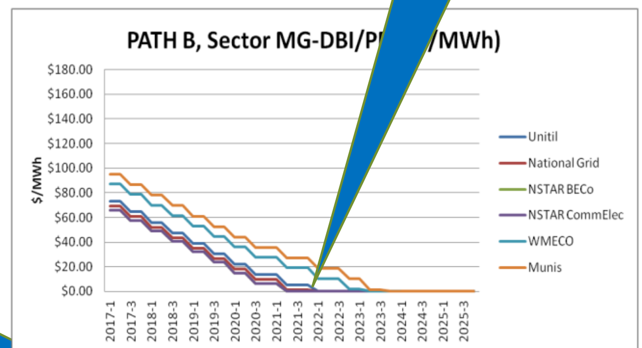


Comparative PBI levels must be viewed in context of raised target (25%-30%)

(13)

APPENDIX D: COMPONENTS OF COST/BENEFIT ANALYSIS

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

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

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

D.1 Overview of Cost Benefit Categories and Subcategories

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

D.1.1 Ratepayer & Participant Costs and Benefits

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

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

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

D.1.2 Secondary Costs and Benefits

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

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

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

D.2 Cost and Benefit Components and Level of Analysis

Within each of these categories, there are a number of individual cost and benefit components that comprise the individual impacts to be considered. Table 43 below illustrates the subcategories associated with these three categories of secondary costs and benefits. A color coding of these broad categories by color code and hue is used throughout to aid the reader in following the various components of this complex analysis.

Table 75: Cost and Benefit Categories and Components

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

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

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

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

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

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

    - Impacts identified as addressed qualitatively will be discussed in a generalized sense later in this report. Table 43 shows which cost and benefit components are quantified, and which are dealt with qualitatively.

In order to clearly illustrate the "flows" or distribution of costs and benefits associated with each policy future, each component of costs and benefits discussed in this section has a table describing how that cost and benefit category manifests as either a cost or benefit (or both) from each of the four perspectives. These tables also identify whether quantitative or qualitative analysis is performed for this study, and in some instances, whether a parametric assumption is used in estimating a quantified impact; the manner in which it is being used, and whether the result accrues as a benefit, cost, or is not considered to be either from each of the four cost-benefit perspectives. Table 44 below presents a key to understanding when each type of data is being used, and if that result is a cost or benefit to the perspective in question, within the sections that follow.

Table 76: Key to Cost and Benefit Description Tables

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

D.3 Category 1: PV System Costs

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

Subcategory	Code	Analysis
System Installed Costs	CB1.1	Quantitative
Ongoing O&M + Insurance Costs	CB1.2	Quantitative
Lease Payments	CB1.3	Quantitative
PILOTs / Property Taxes	CB1.4	Quantitative

ROI (to lenders & investors)	CB1.5	Quantitative
MA Residential RE Tax Credit	CB1.6a	Quantitative
MA Income Taxes	CB1.6b	Quantitative
Federal Incentives (ITC)	CB1.7a	Quantitative
Federal Income Taxes	CB1.7b	Quantitative

For ease of estimation, PV system installed and operating costs are assumed to be independent of the specific state policy futures, primarily driven by global module markets and local scale economies.[106] These costs vary by installation type and in some cases ownership model, but are held constant across alternative policy futures. When calculated installed costs throughout the baseline policy and alternative policy futures, the total costs per year can be stated as:

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

where

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

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

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

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

Table 77: PV System Cost Applicability to Analysis Perspectives

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

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

the Commonwealth at Large **(C@L)**	- Lease Payments - PILOTs/Property Taxes - MA Income Taxes - ROI to Lenders/Investors	-

D.3.1 System Installed Costs

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

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

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

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

Table 78: PV System Installed Cost Impacts by Perspective

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

D.3.2 Ongoing O&M and Insurance Costs

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

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

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

Table 79: Ongoing O&M + Insurance Costs Impacts by Perspective

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

D.3.3 Lease Payments

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

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

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

Table 80: Land Lease Payments Impacts by Perspective

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

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

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

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

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

Table 81: PILOTs / Property Taxes Impacts by Perspective

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

D.3.5 Aggregate Return to Debt & Equity

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

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

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

Table 82: Aggregate Return to Debt & Equity Impacts by Perspective

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

D.3.6 Massachusetts Residential Renewable Energy Tax Credit

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

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

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

Table 83: MA Residential RE Tax Credit Impacts by Perspective

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

D.3.7 Massachusetts Income Taxes

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

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

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

Table 84: MA Income Taxes Impacts by Perspective

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

D.3.8 Federal Incentives (Investment Tax Credit)

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

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

Table 85: Federal Incentives (ITC) Impacts by Perspective

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

D.3.9 Federal Income Taxes

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

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

Table 86: Federal Income Taxes Impacts by Perspective

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

D.4 Category II: Solar Policy

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

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

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

Table 87: Solar Policy Impact Applicability to Analysis Perspectives

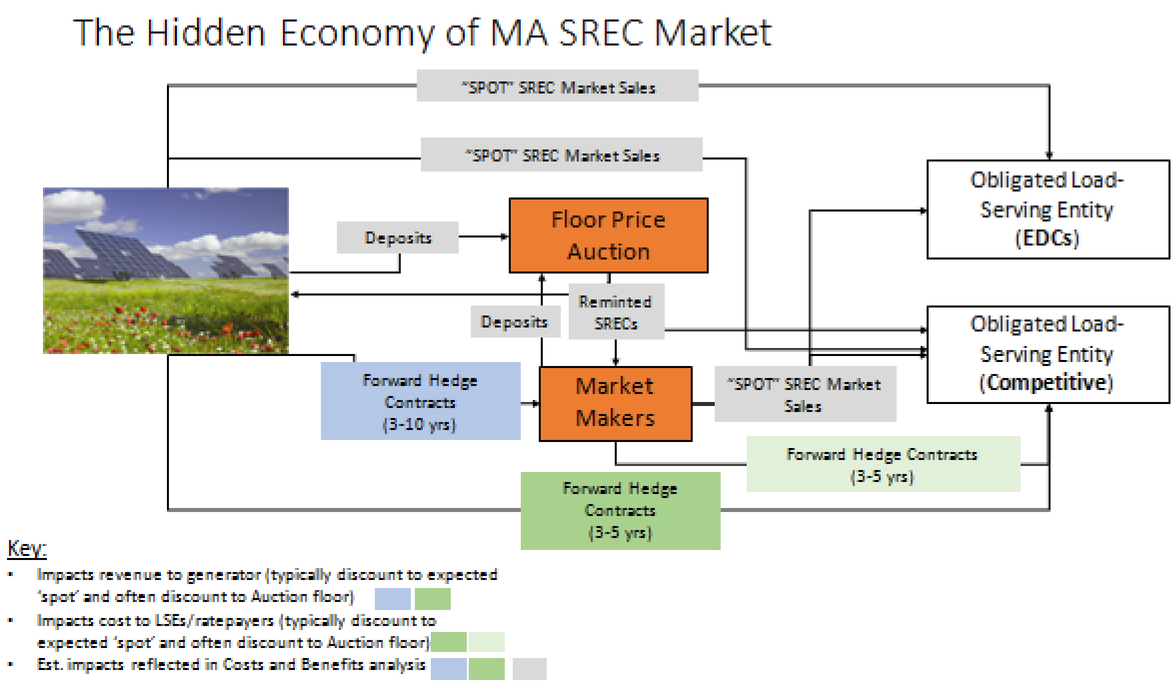
Perspective	Subcategories Accruing as Net Benefits to Some or All With Perspective	Subcategories Accruing as Net Costs to Some or All With Perspective
*Non-Owner Participants **(NOP)***	- N/A	- N/A
*Customer-Generators **(CG)***	- Direct Incentives	- Solar Policy Incremental Admin. and Transaction Costs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

D.4.1 Direct Incentives

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

To calculate the value of SREC payments, it is important to understand the structure of the existing SREC markets, as well as how a hypothetical program (SREC-III) that extends the basic structure of SREC-I and SREC-II to 2025. Figure 76 is an illustration of the main structural flows and features of the Massachusetts SREC market, underscoring the hedging transactions that result in revenues to generators differing from costs to ratepayers.

Figure 76: Schematic Diagram of Hedging Transactions within the SREC Carve-out Market



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

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

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

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

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

Table 88: Direct Incentives Impacts by Perspective

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

D.4.2 Other Solar Policy Compliance Costs

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

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

Table 89: Other Solar Policy Compliance Costs Impacts by Perspective

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

D.4.3 Displaced RPS Class I Compliance Costs

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

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

Table 90: Displaced RPS Class I Compliance Costs Impacts by Perspective

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

D.4.4 Solar Policy Incremental Administrative and Transaction Costs

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

Table 91: Solar Policy Incremental Admin. & Transaction Costs Impacts by Perspective

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

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

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

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

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

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

Table 92: BTM Production within the Billing Month Applicability to Analysis Perspectives

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

D.5.1 Generation Value of On-Site Generation

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

Table 93: Generation Value of On-site Generation Impacts by Perspective

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

D.5.2 Transmission Value of On-Site Generation

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

Table 94: Transmission Value of On-site Generation Impacts by Perspective

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

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

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

Table 95: "Adjusted" Distribution Value of On-site Generation Impacts by Perspective

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

D.5.4 Other Retail Bill Components

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

Table 96: Other Retail Bill Components (Transition, EE, RE) Impacts by Perspective

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

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

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

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

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

Table 97: Net Metering Credits beyond the Billing Month (Including Virtual Net Metering) Applicability to Analysis Perspectives

Perspective	Subcategories Accruing as Benefits	Subcategories Accruing as Costs

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

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

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

Table 98: Offsetting On-site Usage Beyond Current Billing Month Impacts by Perspective

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

D.6.2 Virtual Net Metering

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

Path A is reduced to the value of the wholesale value of electricity. The treatment of net metering credits for virtually net metered systems would be analogous to the treatment of customer-hosted systems.

Table 99: Virtual Net Metering Impacts by Perspective

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

D.6.3 Wholesale Market Sales

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

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

Table 100: Wholesale Market Sales Impacts by Perspective

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

D.6.4 Virtual Net Metering Administrative Costs

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

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

Table 101: VNM Admin Costs Impacts by Perspective

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

D.7 Category V: Electric Market

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

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

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

Table 102: Electric Market Impacts Applicability to Analysis Perspectives

Perspective	Subcategories Accruing as Benefits to Some or All With Perspective	Subcategories Accruing as Costs to All or Some With Perspective

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

D.7.1 Wholesale Market Impacts – Energy

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

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

Table 103: Wholesale Market Price Impacts – Energy Impacts by Perspective

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

D.7.2 Wholesale Market Impacts – Capacity

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

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

Table 104: Wholesale Market Price Impacts – Capacity Impacts by Perspective

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

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

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

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

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

In addition, the analysis described in Section 3.1 revealed that solar PV's electric load carrying capacity (ELCC), which decreases as PV penetration increases and shifts peak hours later into the evening, is substantially higher than the Seasonal Claimed Capacity for intermittent renewables in FCM – the value of which is independent of penetration. As Figure 19 in Section 3.1 shows, solar reduces peak, and thus the ICR, to the extent the peak reduction benefit is not fully captured in solar SCC calculations. The analysis in Section 3.1 also calculates the impact on peak reduction from solar PV as a function of penetration, which is used in these calculations. Thus, this analysis derives both the capacity impacts of distributed solar PV, and the installed capacity reserves (ICR), the net of which is the value of avoided capacity reserve requirements and on-peak line losses (also discussed in Section 3.2 and Section D.7.4).

Table 105: Avoided Generation Capacity Costs (Including Avoided Generation Capacity Reserve Costs) Impacts by Perspective

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

D.7.4 Avoided Line Losses

Line losses represent the generated energy that is lost due to electrical resistance in the process of delivering (i.e. transmitting and distributing) electricity from source to sink. The derivation of loss factors in discussed in Section 3.2. The applicable loss factors are applied to individual cost and benefit components throughout this study, rather than being tallied explicitly as an individual line item. The value of avoided *marginal* losses due to locating generation on the periphery of the distribution system near load is not captured by prices for generation, but accrues broadly to load, and thus to all ratepayers. Thus, the study adjusts many of the costs and benefit subcategories within this analysis using a solar production-weighted line loss formula based on statewide average line loss figures outlined in Table 42 in Section 3.2.

D.7.5 Avoided Transmission Tariff Charges

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

Table 106: Avoided Transmission Tariff Charges Impacts by Perspective

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

D.8 Category VI: Electric Investment Impacts

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

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

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

Table 107: Electric Investment Impacts Applicability to Analysis Perspectives

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

D.8.1 Avoided Transmission Investment – Remote Wind

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

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

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

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

Table 108: Avoided Transmission Investment - Remote Wind Impacts by Perspective

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

D.8.2 Avoided Transmission Investment – Local

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

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

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

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

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

Table 109: Avoided Transmission Investment – Local Impacts by Perspective

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

D.8.3 Avoided Distribution Investment

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

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

- First, estimates of deferral benefits were taken from a literature review. Seven sources were selected to represent a reasonable range of conditions and methodologies, and an average value was calculated from these sources for the area-wide passive deferral benefit of solar PV, as described more fully in Appendix E.[107] These sources included three case studies of active deferral in particular New England locations and four reports with estimates of passive or area-wide deferral impacts and with adequate detail on their methodologies. Where necessary, the estimates from four of these sources were adjusted to be comparable by applying MA-specific and PV-specific factors.
- Second, to confirm the reasonableness of the average distribution deferral value from the literature, that value was compared against a simplified analysis driven by assumptions about distribution feeder load growth, upgrade costs, solar penetration and coincidence of solar output with feeder load.
- Third, the analysis assumes that the percentage of the state's distribution system to which estimates of "active deferral" are applicable; this is the portion of the system that is growing and so will require new capacity or otherwise provides opportunities to defer distribution investments, estimated to be 30%.[108] This was applied to estimates from the literature review to the simplified analysis in Step 2 to get statewide values.[109]

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

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

where

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

However, if distributed solar PV is installed without integration into planning, the net deferral or avoidance benefits accrue in a rather different manner. While current utility planning assumes limited to no distribution

[107] These sources are listed in Appendix E, along with their URLs. Some of them were also referenced in "Review Of Solar PV Benefit & Cost Studies," 2nd Edition, Rocky Mountain Institute, September 2013 (www.rmi.org/elab_emPower), pages 31-34.
[108] For portions of the distribution system on which there is literally no load growth, there is essentially no deferral opportunity for DER. However, the deferral benefit is at its highest with load growth around ½ of 1 percent/year, other things being equal, since DER (at an assumed 10% penetration) can not only defer the upgrade but avoid it for an entire 30-year period.
[109] The average values used in this report will not be representative of any particular location.

deferral or avoidance benefit associated with PV in the short run, it can be assumed that over time, localized distribution planning (or the existence of distribution congestion pricing, if applicable) will take the solar into account in advance, leading to a "passive" deferral value that may be quantifiable in the future. While the passive value cannot currently be calculated on a locational basis without similar location-specific deferral values at many smaller, distribution-level nodes (often known as "buses") the analysis calculates the total deferral value (including an estimate of passive deferral value) that can currently be averaged across each EDC service territory.

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

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

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

where

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

and

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

Table 110: Avoided Distribution Investment Impacts by Perspective

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

D.8.4 Avoided Natural Gas Pipeline

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

When new natural gas-fired power plants are built or add to their capacity, added pipeline capacity to serve those plants may be needed (and under current pipeline-constrained conditions in New England, this can be assumed to be the case).

While solar has a lower capacity value during winter peak electricity (which coincides roughly with peak annual gas demand), increased PV capacity can potentially reduce total investment in gas pipeline capacity. These effects could be accentuated as technologies evolve to optimize PV's dependable capacity.

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

Table 111: Avoided Natural Gas Pipeline Impacts by Perspective

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

D.9 Category VII: Externalities and Other

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

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

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

Table 112: Externalities and Other Impacts Applicability to Analysis Perspectives

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

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

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

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

Table 113: Avoided Environmental Costs CO_2, NO_x and SO_x Impacts by Perspective

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

D.9.2 Avoided Fuel Uncertainty

Avoided fuel uncertainty accounts for the costs associated with the risk of a significant change in the price of fuels for electricity generation (specifically natural gas) and the associated costs of fuel hedging contracts and other instruments that can be avoided by solar PV deployment. In the case of solar PV, the value of avoided fuel cost uncertainty would capture the value of price-certain resource compared to a price-uncertain resource. While quantitative analysis of this value is beyond the scope of this study, the factor was recently included in Maine's Value of Solar Study (Clean Power

Research, LLC; Sustainable Energy Advantage, LLC; Perez Richard; Pace Law School Energy and Climate Center, 2015) released in March 2015. The Maine VOSS quantified this value to be $0.037/kWh (on a 25-year levelized basis) at by estimating the cost associated with eliminating long term price uncertainty with procuring the quantity of natural gas displaced by solar PV. To do this, the authors of that analysis calculated the difference between the non-guaranteed and guaranteed price of natural gas to determine the net present value of hedging natural gas purchases. Thus, it appears that this methodology could be utilized in Massachusetts and could represent a significant value in Massachusetts. We have not, however, included this value within this analysis.

Table 114: Avoided Fuel Price Uncertainty Impacts by Perspective

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

D.9.3 Resiliency

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

Table 115: Resiliancy Impacts by Perspective

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

D.9.4 Impact on Jobs

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

D.9.5 Cost-Benefit Impacts by Perspective

Table 116: Impact on Jobs Impacts by Perspective

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

D.9.6 Policy Transition Frictional Costs

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

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

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

Table 117: Policy Transition Frictional Costs Impacts by Perspective

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

APPENDIX E: BACKGROUND ON AVOIDED DISTRIBUTION INVESTMENT

The Avoided Distribution Investment component was described as follows in Appendix D:

- When solar PV is installed near load, some of it will contribute to changes in EDC planning, such that some upgrade investments will be deferred[110] that otherwise would have been needed to provide additional capacity to meet peak growth; this is referred to as "active" deferral and applies to a subset of distribution area(s).
- In contrast, when solar PV is installed without integration into planning, there may be no deferral benefit in the short run, but over time it can nevertheless be assumed that, with experience, planning will take the solar into account, explicitly or implicitly, and this will lead to a "passive" deferral.
- Active and passive deferrals are estimated on the average and combined for the state.[111]

The Avoided Distribution Investment component represented a benefit to two of the four perspectives in this analysis: Non-Participating Ratepayers and Citizens at Large, as summarized in the following table:

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

The Avoided Distribution Investment methodology for this study had four main steps. The approach and assumptions are summarized below for each step.

Step 1: Literature Review

First, estimates of deferral benefits were taken from a literature review.

The following documents attempt to provide an overview of methodologies that have been and/or should be used to estimate the benefits and costs of solar PV for the T&D systems:

- A Regulator's Guidebook: Calculating the Benefits and Costs of Distributed Solar Generation, Interstate Renewable Energy Council, Inc., 2013, pages 26-30;
- Review Of Solar PV Benefit & Cost Studies, 2nd Edition, Rocky Mountain Institute, September 2013 (www.rmi.org/elab_emPower), pages 31-34.
- Minnesota Value of Solar: Methodology, Minnesota Department of Commerce, Division of Energy Resources, by Clean Power Research, April 9, 2014, pages 31, 36, 41.

These methodologies distinguish between T&D capacity benefits and "grid support" impacts. For present purposes, while grid support benefits and costs may become increasingly important over time,

[110] The deferral may last for many years in some cases, particularly where load growth is slow and the DER penetration is substantial, such that in present value terms the "deferral" is equivalent to "avoiding" most of the investment. See note 3.

[111] In addition to deferral of capacity investments, solar PV may have other grid support benefits, such as frequency and voltage regulation. There may also be grid integration costs that are not internalized through the interconnection process. These are complex subjects with changing technologies and rules, but for present purposes, these were not quantified and may be assumed to largely offset each other.

we do not attempt to quantify them here, since there is little information available with which reliable estimates could be made for Massachusetts. We also assume that, to the extent solar interconnection and integration costs are incurred that are not internalized in the cash flows of solar owners, they are offset by grid support benefits.[112] Therefore, T&D capacity benefits are the only T&D benefits that are quantified in this report.

It is widely accepted that, under certain conditions, solar PV may contribute to economic savings by deferring the need to upgrade certain elements of the T&D system. The primary basis for the estimates of deferral benefits used in the present report is a set of economic values reported for case studies and planning studies that are publicly available. Specifically, the following seven sources provide a representative range of estimates.

1. "DG and Distribution Planning: An Economic Analysis for the Massachusetts DG Collaborative," Navigant Consulting, Attachment G to Report to DPU, Jan. 2006
2. "2014 System Reliability Procurement Report," The Narragansett Electric Company d/b/a National Grid, R.I.P.U.C. Docket No. 4453
3. Grid Solar Boothbay: Order Approving Stipulation, State of Maine Public Utilities Commission Docket No. 2011-138, April 30, 2012, Request for Approval of Non-Transmission Alternative (NTA) Pilot Projects for the Mid-Coast and Portland Areas
4. "The Value of Distributed Photovoltaics to Austin Energy and the City of Austin," Clean Power Research, L.L.C., March 17, 2006
5. "The Value of Distributed Solar Electric Generation to New Jersey and Pennsylvania," for Mid-Atlantic Solar Energy Industries Association & Pennsylvania Solar Energy Industries Association, by Perez, Norris & Hoff, Clean Power Research
6. "The Benefits and Costs of Solar Distributed Generation for Arizona Public Service," by Beach & McGuire, Crossborder Energy, May 8, 2013
7. "Evaluating the Benefits and Costs of Net Energy Metering in CA," prepared for The Vote Solar Initiative, Crossborder Energy, January 2013.

The following table compares the most relevant estimates from these seven sources, and shows their average value: $.016/kWh.

[112] This report has not addressed any possible differences between the Policy Paths in the ability to optimize these unquantified costs and benefits, such as by targeting feeders or other locations with relatively low interconnection costs for solar projects or with relatively high grid support benefits.

				A	B	C	D	E
Key Metrics from Literature Review				T&D Capacity Value (2015 dollars)		Deferral Benefit from PV with Specified DCP (2015 dollars)		
				Potential Deferral		Active Deferral		Statewide
				$/kW or $/kVa	$/kW-year (not PV)	$/kW-year of PV	$/kWh of PV	$/kWh of PV
				Blue= source value Green= calculated value using assumptions as needed				
1	**MA**	DG and Distribution Planning: An Economic Analysis for the Massachusetts DG Collaborative, Navigant Consulting, Attachment G to Report to DPU, Jan. 2006	2006	$35	$5	$8	$0.007	**$0.002**
2	**RI**	2014 System Reliability Procurement Report, The Narragansett Electric Company d/b/a National Grid, R.I.P.U.C. Docket No. 4453	2014			$49	$0.038	**$0.012**
3	**ME**	Grid Solar Boothbay: Order Approving Stipulation, 2012	2012			$281	$0.220	**$0.066**
4	**TX**	The Value of Distributed Photovoltaics to Austin Energy and the City of Austin, Clean Power Research, L.L.C., March 17, 2006	2006	$1,516	$64	$31	$0.025	**$0.007**
5	**NJ & PA**	The Value of Distributed Solar Electric Generation to New Jersey and Pennsylvania, for Mid-Atlantic Solar Energy Industries Association & Pennsylvania Solar Energy Industries Association, by Perez, Norris & Hoff, Clean Power Research	2012					**$0.003**
6	**AZ**	The Benefits and Costs of Solar Distributed Generation for Arizona Public Service, by Beach & McGuire, Crossborder Energy, May 8, 2013	2013					**$0.002**
7	**CA**	Evaluating the Benefits and Costs of Net Energy Metering in CA, prepared for The Vote Solar Initiative, Crossborder Energy, January 2013	2012		$55 (SCE) $77 (SDG&E) ~$80 (PG&E)			**$0.022**
							Average of values above	**$0.016**

One other study appeared too late to add into this average: "Value of Distributed Generation, Solar PV in Massachusetts," Acadia Center, April 2015. Its estimate of statewide deferral value for south-facing solar in Massachusetts -- $.018/kWh -- was only slightly above the average of the seven sources above, so it wouldn't have significantly changed the result.

Other sources provided relevant estimates of distribution investments or capital costs that are potentially deferrable (e.g., load or capacity upgrades), but stopped short of estimating deferral impacts.

As can be seen from the table, the literature includes a wide range of estimates. Also, different metrics are reported that are often not directly comparable. Where necessary (see green values in table), values have been converted to comparable units of dollars per solar kW and cents per solar kWh, using assumptions for solar capacity factor (for column D) and ELCC (solar match, for column E) that are consistent with the rest of the present project.   Values have also been adjusted to 2015 dollars, using a 2.5% annual escalator.

Step 2: Simplified Generic Worksheet of Distribution Deferral

To confirm the reasonableness of the $.016/kWh average distribution deferral value from the literature, that value was compared against a simplified generic worksheet driven by a basic set of assumptions about distribution feeder load growth, upgrade cost, solar penetration and coincidence of solar output with feeder load. This worksheet illustrates the range of potential deferral benefits as these assumptions are varied, and provides additional confidence in the deferral value from the literature in step 1. The following table illustrates a scenario with a deferral from 2018 to 2037, which leads to a 56% savings in the present value of distribution investment required. The assumptions that lead to this scenario are listed below.

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
				Upgrade cost incurred in year when needed							
		Load as % of Capacity		Year of Need for Upgrade		Cost of Upgrade ($000)	Capital Cost & Timing of Upgrades ($000)		Amortized Cost of Upgrades ($000), based on 30-year NPV		
		Existing	with DER	Existing	with DER		Upgrade, No DER	Upgrade, with DER	Upgrades, No DER	Upgrades with DER	Annual Savings ($000)
0	2015	98.0%	83.0%			$ 250			100%	44%	56%
1	2016	98.7%	83.7%	0	0	256			$	$	$
2	2017	99.5%	84.5%	0	0	263			$	$	$
3	2018	100.2%	85.2%	2018	0	269	269		$ 31	$ 4	$ 8
4	2019	101.0%	86.0%	0	0	276			$ 31	$ 4	$ 8
5	2020	101.7%	86.7%	0	0	283			$ 31	$ 4	$ 8
6	2021	102.5%	87.5%	0	0	290			$ 31	$ 4	$ 8
7	2022	103.3%	88.3%	0	0	297			$ 31	$ 4	$ 8
8	2023	104.0%	89.0%	0	0	305			$ 31	$ 4	$ 8
9	2024	104.8%	89.8%	0	0	312			$ 31	$ 4	$ 8
10	2025	105.6%	90.6%	0	0	320			$ 31	$ 4	$ 8
11	2026	106.4%	91.4%	0	0	328			$ 31	$ 4	$ 8
12	2027	107.2%	92.2%	0	0	336			$ 31	$ 4	$ 8
13	2028	108.0%	93.0%	0	0	345			$ 31	$ 4	$ 8
14	2029	108.8%	93.8%	0	0	353			$ 31	$ 4	$ 8
15	2030	109.6%	94.6%	0	0	362			$ 31	$ 4	$ 8
16	2031	110.4%	95.4%	0	0	371			$ 31	$ 4	$ 8
17	2032	111.3%	96.3%	0	0	380			$ 31	$ 4	$ 8
18	2033	112.1%	97.1%	0	0	390			$ 31	$ 4	$ 8
19	2034	112.9%	97.9%	0	0	400			$ 31	$ 4	$ 8
20	2035	113.8%	98.8%	0	0	410			$ 31	$ 4	$ 8
21	2036	114.6%	99.6%	0	0	420			$ 31	$ 4	$ 8
22	2037	115.5%	100.5%	0	2037	430		430	$ 31	$ 4	$ 8
23	2038	116.4%	101.4%	0	0	441			$ 31	$ 4	$ 8
24	2039	117.2%	102.2%	0	0	452			$ 31	$ 4	$ 8
25	2040	118.1%	103.1%	0	0	463			$ 31	$ 4	$ 8
26	2041	119.0%	104.0%	0	0	475			$ 31	$ 4	$ 8
27	2042	119.9%	104.9%	0	0	487			$ 31	$ 4	$ 8
28	2043	120.8%	105.8%	0	0	499			$ 31	$ 4	$ 8
29	2043	121.7%	106.7%	0	0	512			$ 31	$ 4	$ 8
30	2044	122.6%	107.6%	0	0	524			$ 31	$ 4	$ 8
					Sum		269	430	878	388	490
					Net Present Value		**235**	**104**	**356**	**157**	**199**
					Levelized Values				27	0	5
					Upgrade and Savings Percentages				**100%**	**44%**	**56%**

The assumptions which lead to this deferral from 2018 to 2037 are listed below, including a distribution feeder load growth rate of 0.75%/year, an upgrade cost of $250/kW, penetration of 15% for solar (or a combination of solar and other Distributed Energy Resources (DER), and coincidence of 33% between solar output and feeder load (equivalent to the ELCC, but at the distribution level; see Section 3.1 for a chart of this value over time). The following table also summarizes the results of this deferral scenario in present value terms:

- a 56% savings in the present value of distribution investment required, and
- a distribution deferral value of $.055/kWh for PV on this feeder (for "active deferral") from this simple model.[113]

Two additional calculations appear at the bottom of this table, which are described in Steps 3 and 4 below:

- a statewide (or "passive") distribution deferral value of $.016/kWh (which is nearly the same as the average from the literature in Step 1), after assuming (per Step 3 below) that 30% of the feeders statewide would have an opportunity for such an active deferral, and
- a net statewide distribution deferral value of $.008/kWh after assuming that deferral would be feasible on 50% of the feeders despite technical challenges discussed in Step 4 below.

Illustrative Model of Upgrade Deferral by DER (4/27/15)

Inputs: (input cell)

#	Inputs	Value
1	Feeder Capacity (MW)	1.0
2	Current Load %	98%
3	Current Load (MW)	1.0
4	Peak Load Growth	0.750%
5	New DER as % of Feeder Load	15.0%
6	DER Reduction of Load (MW)	0.147
7	Upgrade Cost/kW*	$ 250.00
8	Upgrade Capacity	100%
9	Upgrade Capacity (MW)	1.0
10	Cost ($000, $/kW-yr)	$250
11	Escalation of Upgrade Cost	2.5%
12	Discount Rate/WACC	7.0%
13	Carrying Chg/ Fixed Chg Rate (see sheet)	13.3%
14	Solar DCP (Distrib Contrib as % of PV kW)	33%
15	Solar MW (AC)	0.445
16	Solar MWh/yr	567
17	Deferral years	19
18	MWh in deferal years	10,771

Results:

Present Value Analysis:	Capital Costs: Upgrade, No DER	Capital Costs: Upgrade, with DER	Annual Costs: Upgrade, No DER	Annual Costs: Upgrade, with DER
Upgrade Cost ($000)	$ 220	$ 97	$ 333	$ 147
Savings ($000)		$ 123		$ 186
Savings (% reduction)		56%		**56%**
Savings $/kW of DER		$ 834		$ 1,262
Savings $/kW of Solar		$ 275		**$ 1,043**

	This Run	Weighted*
Cumulative Savings $/kWh of Solar	$ 0.0617	$ 0.0548

** Weighted by load growth and DER penetration*

	Active	% of load on feeders with growth	Statewide
Distribution Deferral for PV across territory from model ($/kWh)	$ 0.0548	30%	$ 0.0164
Average of 5 values from the literature ($/kWh)	$ 0.0542	30%	$ 0.0163
Weighted/selected results	$ 0.0542		$ 0.0163
Adjustment for technical issues			50%
Assumed Distribution Deferral for PV ($/kWh)			$ 0.0081

Step 3: Opportunities to Defer Distribution Investments

[113] The amortized Annual Savings in column (10) are divided by the cumulative solar kW installed each year to defer the investment, and then the resulting $/kW annual savings are divided by solar output each year and levelized for this active deferral value of $.055/kWh.

We make an assumption for the percentage of the state's distribution system to which estimates of "active deferral" are applicable; this is the portion of the system that is growing and so will require new capacity or otherwise provides opportunities to defer distribution investments.[114] We have used 30 percent as a placeholder assumption for this factor. This was applied to estimates from four of the literature sources and to the results from the worksheet in Step 2 to get a statewide distribution deferral value of $.016/kWh.[115]

Step 4: Technical Factors to Achieve Deferral

There are a number of factors that may be required in order for distribution planners to sufficiently rely upon solar DG to actually achieve a deferral of upgrade investments. Some of these factors may affect the physical availability of PV to reduce load under challenging conditions, such as following power quality disturbances and grid outages; planning lead time is also a factor.

These factors include:

- IEEE 1547 standards requires DG to trip for low voltage and other disturbances, and low-voltage ride-through may be incompatible with anti-islanding protection;
- Planners can't count on PV to be on-line instantly as power is restored after outage; and,
- Physical assurance may be needed to keep load off the distribution system if the solar goes down.

These issues are important and should be addressed through further R&D, pilot testing and policy development. This will lead to better information to estimate their impact on the benefits and costs of solar for the T&D system. In the meantime, we simply apply a factor for the percentage of PV that can be counted upon for distribution deferral through the use of physical assurance, storage, smart inverters with ride-through, linked demand response and/or other means. We have used 50 percent as a placeholder assumption for this factor, resulting in a net statewide distribution deferral value of $.008/kWh.

Results

The result for steps 1 through 3 for this illustration was $.016 average statewide value of Avoided Distribution Investment per kWh of solar PV. After applying the 50% factor from Step 4, the net value = $.008/kWh. The modeling for this study replaced the static assumption for peak coincidence described above with the with the solar penetration-dependent value for each year, calculated as discussed in Section 3.1.

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

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

Evaluation of Net Metering in Vermont Conducted Pursuant to Act 99 of 2014

Public Service Department
October 1, 2014
Revised November 7, 2014

1 Introduction
Act 99 of the 2014 Vermont legislative session directed the Public Service Department (Department) to complete an evaluation of net metering in Vermont and file the resulting report with the Public Service Board. The report is required to include an analysis of each of the items described under 30 V.S.A. §8010(d)(1)-(9), paraphrased here:

- *§8010(d)(1) – Analyze Current Pace of Net Metering deployment Statewide and by Utility*
- *§8010(d)(2) – Recommend future pace of net metering deployment Statewide and by Utility*
- *§8010(d)(3) – "Existence and degree" of cross subsidy between Net Metered customers and Others.*
- *§8010(d)(4) – Effect of net metering on retail electricity provider infrastructure and revenue.*
- *§8010(d)(5) – Benefits to net metering customers of connecting to the distribution system*
- *§8010(d)(6) – Economic and environmental benefits of Net Metering*
- *§8010(d)(7) – Reliability and Supply diversification costs and benefits.*
- *§8010(d)(8) – Ownership and transfer of environmental attributes of energy generated by Net Metered Systems*
- *§8010(d)(9) – Best practices for net metering identified from other states*

This report to the Public Service Board (Board) addresses the legislative request. It builds directly from the report completed by the Department in January 2013 pursuant to Act 125 of the 2012 legislative session, updating assumptions and methodology as appropriate and described herein. Aspects of the methodology and approach that are not significantly changed from the 2013 Report will not be restated in this report. Instead, interested readers can find the 2013 Report on the Department's website at http://publicservice.vermont.gov/topics/renewable_energy/net_metering.

The Department undertook several steps to address the legislative request and evaluate net metering in Vermont. The Department issued a letter to stakeholders describing its proposed approach to the report, to which we received several sets of comments. Many of these comments urged the Department to hold a set of technical working group meetings inviting stakeholders to address each Act 99 criteria. Given time constraints and the Public Service Board process that will follow this report, significant stakeholder interaction and feedback was not solicited for this report. Rather, this report is intended to *start* the dialogue expected to take place via the upcoming Public Service Board process. The Department did hold a meeting for stakeholders to vet the updated structure and assumptions in the spreadsheet cost-benefit model.

Section 2 of this report begins with a brief background describing the changes to net metering contained in Act 99 of 2014, and the current status and pace of net metering deployment in Vermont. Section 3 updates the analysis of the existence and magnitude of any cross subsidy created by the current net metering program that was originally completed pursuant to Act 125 of 2012. Section 4 addresses lessons learned and guiding principles for net metering program design from a review of recent literature discussing these issues. Finally, Section 5 addresses the balance of the Act 99 criteria.

2 Background
A brief history of Vermont's net metering statute can be found in the 2013 Report. This section describes the changes to net metering contained in Act 99 of 2014. It will also update the current status and pace of net metering deployment Statewide and by utility.

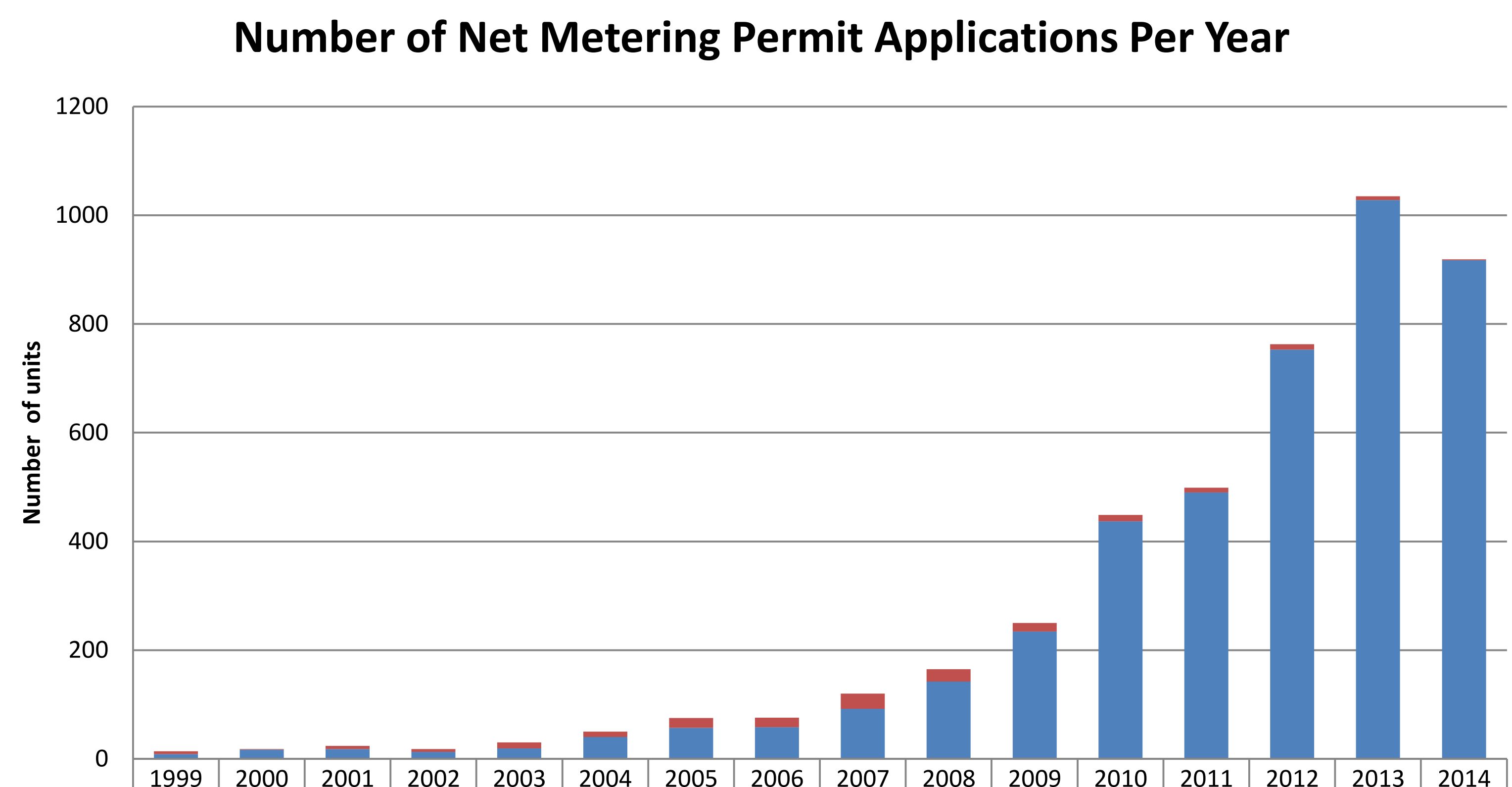
2.1 Act 99 of 2014

Act 99 of 2014 amended Vermont's net metering statute in the following relevant ways:

- Utilities must now allow net metering up to 15% of their peak capacity, changed from 4%.
- For systems over 15 kW the solar credit is now calculated by subtraction from 19 cents, down from 20 cents.
- Following the 10 year period of the solar credit, the systems are to be credited at the blended rate, rather than the highest residential rate. The solar credit is also calculated by reference to the blended rate.
- Net metered customers may now assign the renewable energy attributes of their generation to their utility for retirement on their behalf.
- Approval for various pilots and alternate net metering structures for utilities that have met certain criteria.

2.2 Current pace of net metering deployment statewide and by utility

Net metering has experienced rapid growth over the last seven years as the demand for local renewable energy has grown, costs have decreased, and access to renewables has broadened. As can be seen in Exhibit 1, solar PV has had the most substantial growth of all the renewable technologies. The number of PV systems applying for net metering permits annually has grown by a factor of more than seven since 2008.



	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Fuel Cell	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	5	1	6	5	11	10	18	18	28	23	16	12	9	10	7	2
Solar	9	17	18	13	19	39	57	58	92	141	232	435	490	752	1027	917
Methane	0	0	0	0	0	1	0	0	0	1	2	2	0	1	1	0

Exhibit 1. *Number of net metering applications & registrations annually. (Data as of 9/26/14.)*

With the recent rise in number of PV applications, solar now accounts for 93.5% of all net metering capacity. Wind turbines represent less than 3% of all net metered capacity and hydroelectric represents approximately 2.2% (see Exhibit 2). To date, there have been no net metered fuel cells or combined heat and power systems in Vermont.

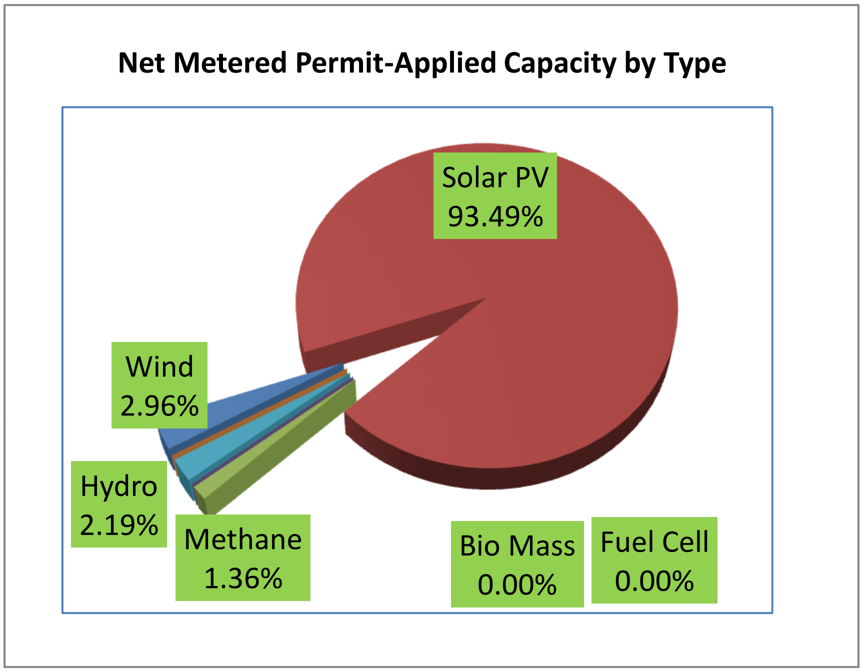
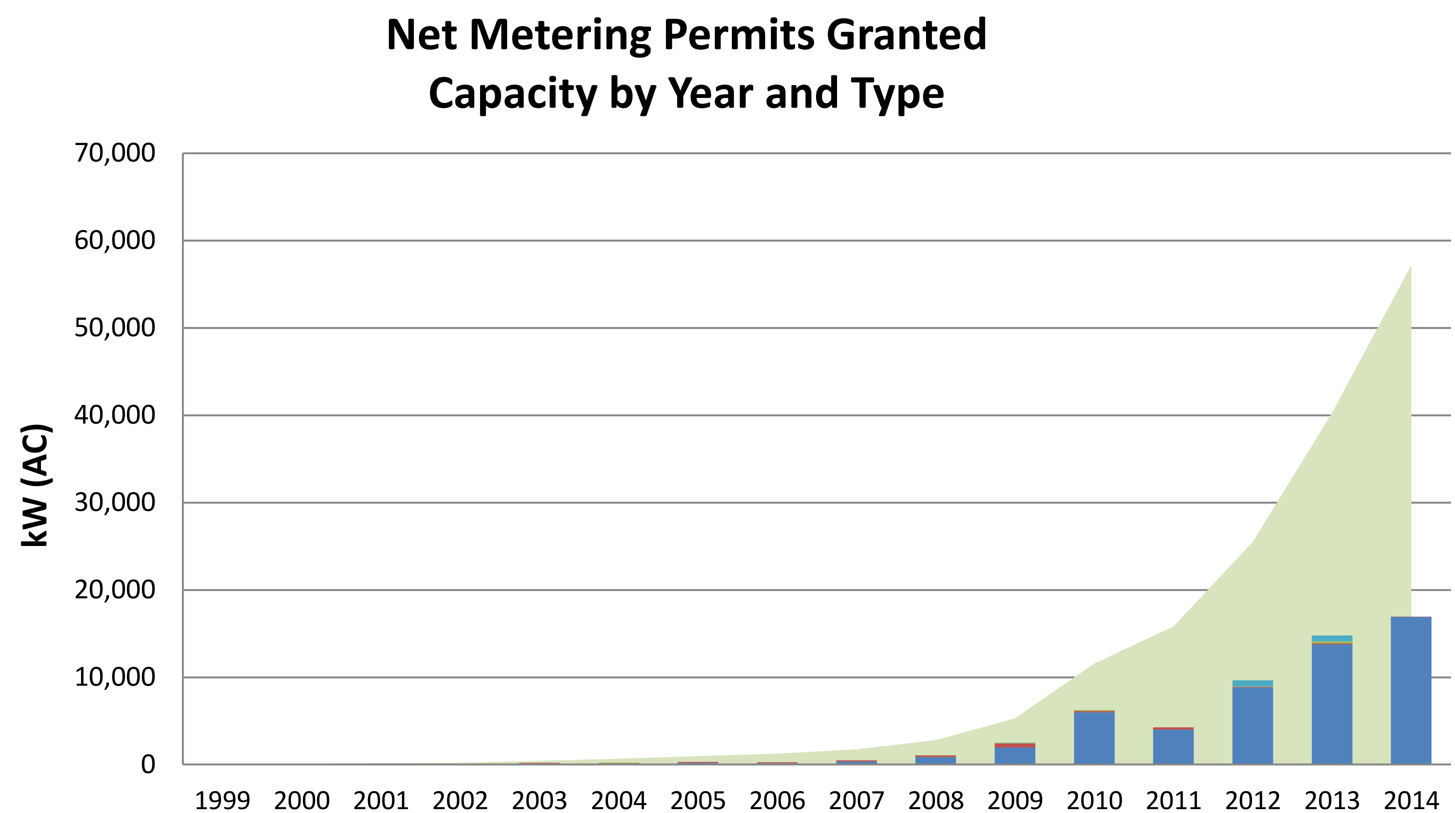


Exhibit 2. *Capacity of net metering permit applications by technology type (as of 9/26/14)*

The exponential increase in the number of PV system installations has driven not only the overall number of net metered systems but also the total growth of permitted net metered system capacity to 57.2 MW (see Exhibit 3). In addition to permitted systems, and additional 6.8 MW of proposed net metered projects have applied for permits but not yet received them, for a total of 64 MW.



	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Cumulatve Capacity	50	99	177	224	436	670	980	1,255	1,749	2,798	5,307	11,568	15,828	25,496	40,274	57,188
Hydro	-	-	-	-	-	-	-	-	-	-	18	-	-	716	664	-
Methane	-	-	-	-	-	65	-	-	-	19	39	127	-	49	248	-
Wind	32	10	28	31	98	72	123	102	147	158	482	154	239	66	125	12
Solar	18	39	50	16	114	97	187	174	347	872	1,969	5,981	4,021	8,838	13,741	16,902

Exhibit 3. *Capacity of net metering permits granted by type and cumulative capacity. (Data as of 9/26/14.)*

The capacity histogram (Exhibit 4) shows that 48% of net metering systems that have applied for permits to date are less than 5 kW, 36% are between 5-10 kW and fewer than four percent are larger than 100kW. Notably, a significant number of 500kW applications have been submitted in 2014, potentially indicating a trend towards larger group net metering systems.

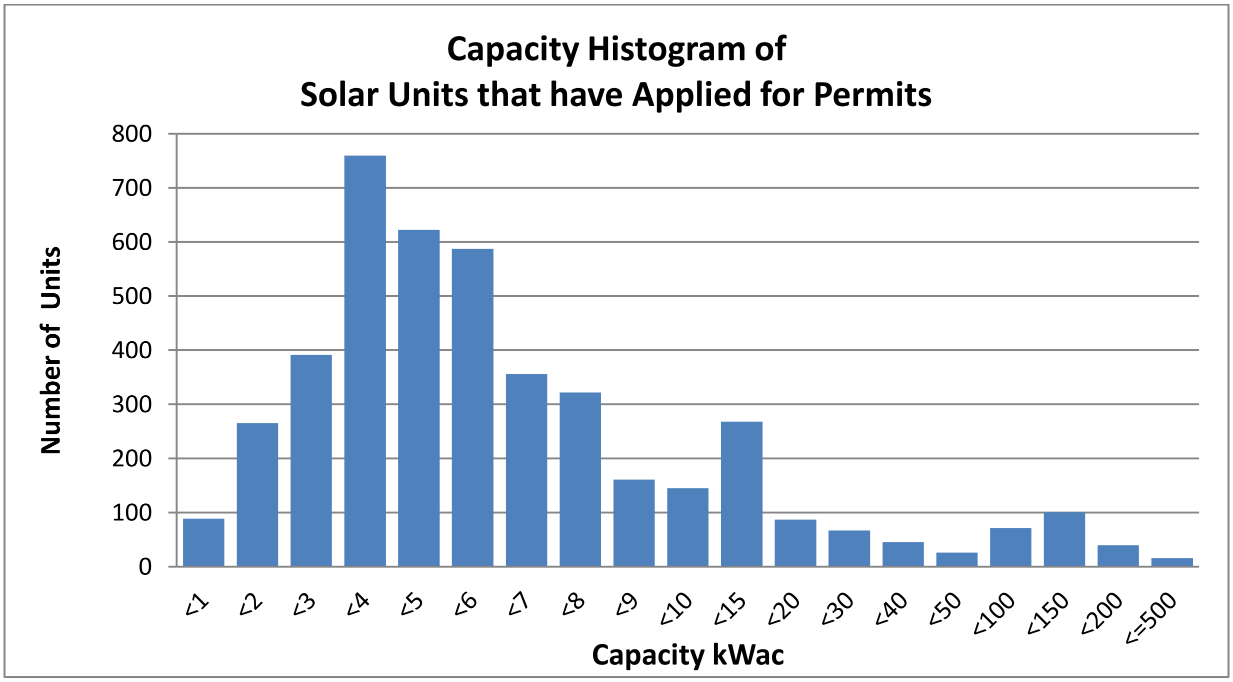


Exhibit 4. *Histogram by Capacity (in kW AC) of all net metered solar PV system permit applications (as of 9/26/14)*

While the growth has been rapid, 63.8 MW of net metered systems represents a small fraction of Vermont's overall electrical portfolio. GMP, VEC, WEC, Hardwick, Jacksonville and Morrisville have all exceeded the previous 4% capacity cap. If all permitted and constructed, net metered systems to date would produce less than 2% of the electric energy Vermont uses each year or approximately 80 GWh per year.

	Solar PV		Wind		Methane		Hydroelectric		Total	Approx.
Utility	**Count**	**Capacity**	**Count**	**Capacity**	**Count**	**Capacity**	**Count**	**Capacity**	**Capacity**	**% of peak**
Barton	8	43	2	19	0	0	0	0	62	2.0%
BED	96	1,836	4	15	1	248	0	0	2,099	3.1%
Enosburg	12	83	0	0	0	0	0	0	83	1.5%
GMP	3,376	50,010	107	1,231	7	489	10	1,399	53,128	6.9%
Hardwick	57	473	9	79	0	0	0	0	552	8.0%
Hyde Park	19	87	1	10	0	0	0	0	97	3.8%
Jacksonville	2	159	3	11	0	0	0	0	170	14.4%
Johnson	6	220	0	0	0	0	0	0	220	7.8%
Ludlow	0	0	0	0	0	0	0	0	0	0.0%
Lyndonville	43	276	2	99	0	0	0	0	374	1.7%
Morrisville	28	493	4	38	0	0	0	0	531	5.8%
Northfield	17	107	0	0	0	0	0	0	107	2.0%
Orleans	1	6	0	0	0	0	0	0	6	0.2%
Stowe	32	276	0	0	1	20	0	0	296	1.6%
Swanton	7	33	0	0	0	0	0	0	33	0.3%
VEC	498	4,174	45	332	1	96	0	0	4,602	5.5%
WEC	214	1,566	7	60	0	0	0	0	1,626	10.2%
TOTAL	**4,416**	**59,842**	**184**	**1,892**	**10**	**853**	**10**	**1,399**	**63,986**	**6.2%**

Exhibit 5. *Number of net metered permit applications and the capacity of those generators (in kW), by utility and type of generation, with the approximate percent of each utility's 2013 peak load.*

3 Existence and degree of cross-subsidy

The Department's Act 125 report described a statewide average analysis of the existence and degree of potential cross-subsidy between those customers participating in net metering and those not participating. This section describes several updates to that analysis and provides summary results by utility. The analysis uses the same logical structure as the Act 125 analysis. The reader is encouraged to review that report for examination of choices to include or exclude certain costs and benefits, the perspective from which the analysis is conducted, which generation to include, etc.

3.1 Costs and benefits

The Department's analysis includes the following costs:

- Lost revenue (due to participants paying smaller electric bills);
- Vermont solar credit, for solar PV systems; and
- Net metering-related administrative costs (engineering, billing, etc.).

The Department's analysis includes the following benefits:

- Avoided energy costs, including avoided costs of line losses and avoided internalized greenhouse gas emission costs;
- Avoided capacity costs, including avoided costs of line losses;
- Avoided regional transmission costs (costs for built or un-built pooled transmission facilities, or PTF, embodied in the ISO-NE Regional Network Service charge and other regional changes allocated in a similar fashion);
- Avoided in-state transmission and distribution costs (avoiding the construction of new non-PTF facilities). New for this report is the separation between transmission and distribution costs, in order to account for differences between utilities;
- Market price suppression in both energy and capacity markets; and
- Potential future regulatory value associated with retention of renewable energy credits in Vermont;

Net costs and benefits were calculated both including and excluding the value of avoided greenhouse gas emissions that are currently not internalized in the cost of energy or the value of renewable energy credits. Ratepayers face a risk that more costs associated with mitigation of greenhouse gases from electricity production will be internalized into energy prices in the future, potentially leading to stranded assets if resource decisions are made without consideration of the value of greenhouse gas emissions mitigation or abatement.

Costs and benefits are determined from a Vermont ratepayer perspective; transfers from entities which are not Vermont ratepayers to Vermont ratepayers are included; any potential transfers between Vermont ratepayers are not included. Utility-specific analysis attempts to measure costs or benefits that accrue to ratepayers of each utility.

The assumptions used for each of these costs and benefits are described in more detail in Section 3.2 below.

3.2 Modeling assumptions

The spreadsheet model[1] estimates the costs and benefits incurred as a result of any single net metering installation installed in 2015 or a later year. It projects costs and benefits over the 20-year period following installation, allowing examination of the potential changing costs and benefits over that period as well as calculation of a levelized net benefit or cost per kWh over 20 years. The Act 125 report includes a summary of what the spreadsheet model does not attempt to do; this list is still accurate, aside from the new attempt to capture differences between utilities and a revised treatment of the value of renewable attributes.

3.2.1 Utility-specific costs and benefits

In the context of this study, "costs" and "benefits" are measured from the ratepayer standpoint. The utility regulatory structure in Vermont (including GMP's alternative regulation plan, the co-op structure of VEC and WEC, and the municipal structure of the state's other utilities) results in the relevant set of costs and benefits faced by the state's utilities being passed to the state's ratepayers. As a result, the analytical framework treats utility costs as ratepayer costs, and utility benefits as ratepayer benefits.[2]

3.2.1.1 Costs

Net metering reduces utility revenue by enabling a participating customer to provide some of their own electricity (including, at times, spinning their meter backward while exporting energy), which reduces their monthly bill. In order to calculate the size of this reduction due to a modeled net metering installation, the model requires the energy produced per year, along with the expected average customer rate, and any solar credit. The Department collected current rates from each of the state's utilities. We used the residential rate structure, as changes in Act 125 established that nearly all net metered customers will see credit to their bills at the residential rate. Act 99 changed the calculation of credits to use the blended rate (defined as the average rate faced by an average residential customer over all of their usage), rather than the highest residential rate. We used the 2013 average residential consumption of each utility to calculate this blended rate.

Rates were forecast to change in the future using the same methodology employed in the Act 125 report. This methodology incorporates forecasts of energy, capacity, and transmission, and other costs, and accounts for internally consistent avoided energy costs and lost rate revenue.

The Department made no changes to how administrative costs were calculated, and did not vary them by utility.

The Department modeled the costs to non-participating ratepayers due to the current net metering program in each utility territory, including the alternate program in effect for Washington Electric Cooperative members. We understand the purpose of the Board investigation subsequent to this report is to consider alternate net metering program designs; these alternatives would be expected to have different costs.

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[1] Available for download from http://publicservicedept.vermont.gov/topics/renewable_energy/net_metering.
[2] Externalities, such as the externalized portion of the value of greenhouse gas emission reductions, do not follow this pattern.

3.2.1.2 Benefits

3.2.1.2.1 Avoided energy cost

From the perspective of the regional electric grid or a utility purchasing power to meet its load, net metering looks like a load reduction. A utility therefore purchases somewhat less power to meet the needs of their customers. While Vermont utilities purchase much of their energy through long-term contracts, this kind of moment-by-moment change in load is reflected in changes in purchases or sales on the ISO-NE day-ahead or spot markets. The Department assumes that the energy source displaced or avoided by the use of net metering is energy purchased on the ISO-NE real-time spot markets (the difference between day-ahead and spot markets over the course of the year is relatively minor).

The Department calculated a hypothetical 2013-14 avoided energy cost on an hourly basis by multiplying the production of real Vermont generators by the hourly price set in the ISO-NE market. This annual total value was then updated to 2015 and beyond by scaling the annual total price according to a market price forecast. These calculations indicate that fixed solar PV had a weighted average avoided energy price 9% lower than the annual ISO-NE average spot market price, 2-axis tracking solar PV is equal to the annual average spot market price, and small wind is 29% higher. This is a change from the Act 125 report, and is driven primarily by the recent high ISO-NE market prices in the winter.

The Department assumed that the capacity factor for each solar technology is projected capacity factor using the NREL PVWatts tool for a location in Montpelier, using all PVWatts default settings. The assumed capacity factor for wind is the 2013-14 capacity factor of the real Vermont generator used to calculate the correlation. Separating the capacity factor from the price-performance correlation allows the analysis to correct for differences between the typical capacity factors expected over many years for a generic facility and the capacity factors exhibited for a particular generator in only one year.

The Department's market energy price forecast is based on that developed filed by the Department in Docket 8010, related to the setting of avoided costs in the context of Public Service Board Rule 4.100. This is a forecast of Vermont's Locational Marginal Price – for energy measured at the VELCO system border. Energy generated by net metering systems, however, is produced on distribution circuits and often used locally; the difference between the energy avoided at the VELCO border and the energy produced at the net metering system is line losses. The Department updated line loss values consistent with the recent updated analysis completed for the marginal line losses avoided from load reductions associated with energy efficiency in proceeding EEU-2013-07. Across different costing periods, these marginal losses average approximately 11%.

Exhibit 6: *Department assumptions and forecasts of avoided energy, capacity, regional transmission, and in-state transmission and distribution costs, along with assumed self-consistent residential rate forecast, developed for this study. Values are in nominal dollars.*

	Energy ($/MWh)	Capacity ($/kW-month)	Regional transmission (PTF) ($/kW-month)	Vermont Transmission (non-PTF) ($/kW-month)	Vermont Distribution (non-PTF) ($/kW-month)
2015	$67.51	$3.01	$8.17	$3.42	$9.26
2016	$59.04	$3.27	$8.75	$3.46	$9.36
2017	$55.24	$5.41	$9.33	$3.52	$9.53
2018	$47.64	$9.84	$9.93	$3.50	$9.46
2019	$49.31	$11.97	$10.56	$3.57	$9.65
2020	$50.23	$12.18	$11.23	$3.64	$9.84
2021	$54.62	$12.43	$11.95	$3.68	$9.97
2022	$53.71	$12.68	$12.71	$3.73	$10.08
2023	$58.30	$12.95	$13.52	$3.74	$10.12
2024	$59.70	$13.22	$14.39	$3.78	$10.23
2025	$65.27	$13.49	$15.30	$3.84	$10.38
2026	$66.99	$13.77	$16.28	$3.88	$10.49
2027	$72.34	$14.07	$17.32	$3.91	$10.59
2028	$73.12	$14.37	$18.42	$3.95	$10.69
2029	$80.24	$14.64	$19.59	$3.98	$10.78
2030	$81.48	$14.91	$20.84	$4.02	$10.87
2031	$84.42	$15.17	$22.17	$4.05	$10.95
2032	$80.03	$15.45	$23.58	$4.08	$11.03
2033	$85.70	$15.73	$25.09	$4.10	$11.10
2034	$84.57	$16.01	$26.69	$4.13	$11.17
2035	$91.27	$16.30	$28.39	$4.15	$11.24
2036	$91.82	$16.59	$30.20	$4.17	$11.29
2037	$97.62	$16.89	$32.12	$4.19	$11.34
2038	$97.63	$17.20	$34.17	$4.21	$11.39
2039	$107.50	$17.51	$36.35	$4.22	$11.42
2040	$108.13	$17.82	$38.67	$4.23	$11.45

3.2.1.2.2 Avoided capacity cost

From the bulk grid perspective, net metering systems look like a reduction in demand, and therefore reduce the utility's cost for capacity. There are multiple potential methods to measure the effective capacity of generators with respect to different purposes. In determining the peak coincidence factors described in this and the following subsections, the Department examined the timing of the relevant peaks: ISO-NE's peak for capacity costs, Vermont summer peaks for in-state transmission costs, monthly Vermont peaks for RNS costs, and utility-specific peak hours for distribution costs. The ability of variable generators to help avoid ISO-NE capacity costs depends on the level of generation during the summer hours when ISO-NE's region-wide grid demand peaks. The Department calculated coincidence values by averaging the production from generic fixed and tracking solar PV systems as well as an example small wind generator during the months and hours (e.g. July hours ending 5pm or August hours ending 3pm) of the ISO-NE peaks since 2003.

Exhibit 7: *Department assumptions of net-metered generators' performance during peak times used to calculate values of avoided capacity, avoided regional RNS cost, and avoided in-state transmission infrastructure. Each value shows the fraction of the system's rated capacity that is assumed in the calculation of the value of the three avoided costs. For example, in calculating the value of avoided capacity costs due to a fixed solar PV system with a nameplate capacity of 100 kW, the system is assumed to reduce capacity costs by the same amount as a system that can output 52 kW and is always running or perfectly dispatchable.*

	Capacity	RNS	In-state Transmission
Fixed PV	0.520	0.210	0.536
Tracking PV	0.579	0.230	0.551
Wind	0.082	0.121	0.058

The capacity price forecast assumed by the Department, and used by default in the model, is based on that developed for use in Docket 8010 relating to avoided costs and Rule 4.100. The resulting capacity price forecast (in nominal dollars) is shown above in Exhibit 6.

3.2.1.2.3 Avoided regional transmission costs

Regional Network Service (RNS) charges are charged by ISO-NE to each of the region's utilities to pay for the cost of upgrades to the region's bulk transmission infrastructure. These are costs that have already been incurred, or are required to meet reliability standards, and thus cannot be entirely avoided – only their allocation among New England ratepayers can be changed. Avoiding these costs through net metering shifts the costs to ratepayers in other states. RNS charges are allocated to each utility based on its share of the monthly peak load within Vermont. Exhibit 7 shows the values for relevant peak coincidence calculated by considering the production expected from generators of each type during the hours of each month when peaks have occurred since 2003.

The values assigned to this cost are based on the ISO-NE forecast of the next 3 years' worth of RNS charges, and escalated based on historical increases in the Handy-Whitman Index of public utility construction costs. The resulting regional transmission price forecast (in nominal dollars) is shown above in Exhibit 6.

3.2.1.2.4 Avoided in-state transmission and distribution costs

In-state transmission and distribution costs are those costs incurred by the state's distribution utilities or VELCO and which are not subject to regional cost allocation. The values used in this model are derived from those developed by a working group consisting of representatives from the state's distribution, transmission, and efficiency utilities, and the Department in proceeding EEU 2011-02 for the update to the electric energy efficiency cost-effectiveness screening tool.

The Department updated the net metering model to separately consider avoided in-state transmission and distribution costs. Burlington Electric Department's forecasts contained in their Integrated Resource Plan show that even without the effects of energy efficiency, there are no load growth related infrastructure investments planned within the next 20 years. Thus, they are assumed to not have any avoided distribution costs. All other utilities are assumed to have avoided distribution costs consistent with the statewide average cost.

The in-state transmission and distribution upgrades deferred due to load reduction or on-site generation (such as net metering) are driven by reliability concerns. Therefore, rather than average peak coincidence for a net metering technology, the critical value is how much generation the grid can rely on seeing at peak times. Therefore, the Department calculated "reliability" peak coincidence values, separate from the "economic" peak coincidence used in avoided capacity and regional transmission cost calculations. The Department calculated reliability peak coincidence for in-state transmission by calculating the weighted average production from generators of each type during the July afternoon hours when Vermont's summer peak has occurred since 2003. These values are shown in Exhibit 7.

The Department calculated distribution peak coincidence values separately for each of the state's distribution utilities. The methodology is implemented in a spreadsheet tool available for download from the Department's website.[3] The methodology was as follows: First, the Department examined the 2013 hourly loads from each of the state's utilities. Load-growth-related distribution infrastructure needs are driven by the extremes of utility load, so the first step was to identify the 5% of all hours (438 hours over the year) during which the utility had the highest load. These were then collected into month-hour pairs (such as the hour ending 6pm in January of the hour ending 3pm in July). Month-hours with at least 9 high-load hours were then identified for each utility. This filter produced lists of between 13 and 26 month-hour pairs during which avoided load would be most likely to avoid the need for infrastructure investments. The next step was to calculate the average production for each type of generation during these high-load hours, compared with the generator's peak capacity. Exhibit 8 shows the resulting coincidence factors.

Exhibit 8. *Utility-specific distribution peak coincidence factors for each generator type.*

Utility	PV: Fixed	PV: 2-Axis Tracker	Small Wind
VT Average	0.223	0.269	0.124
Barton	0.026	0.065	0.176
BED	0.404	0.484	0.074
Enosburg	0.160	0.201	0.098
GMP	0.219	0.261	0.115
Hardwick	0.009	0.027	0.194
Hyde Park	0.062	0.052	0.205
Jacksonville	0.145	0.229	0.156
Johnson	0.218	0.308	0.140
Ludlow	0.077	0.101	0.147
Lyndonville	0.128	0.196	0.144
Morrisville	0.287	0.310	0.105
Northfield	0.054	0.072	0.165
Orleans	0.262	0.378	0.118
Stowe	0.103	0.151	0.128
Swanton	0.306	0.374	0.113
VEC	0.033	0.083	0.180
WEC	0.000	0.001	0.193

[3] Available for download from http://publicservicedept.vermont.gov/topics/renewable_energy/net_metering.

3.2.1.2.5 Market price suppression

Reductions in load shift the relationship between the supply curve and demand curve for both energy and capacity, resulting in changes in market price. Because net metering looks like load reduction, the Department has approximated the market price suppression effect using analysis based on the 2013 Avoided Energy Supply Cost (AESC) study's calculation of the demand reduction induced price effect ("DRIPE") for Vermont. This is the same (but updated) source as used in the Act 125 report.

3.2.1.2.6 Value associated with renewable energy credits

The model allows for assignment of a value that ratepayers see that is attributable to the environmental attributes of the energy generated by a net metered system. Act 99 allows net metering participants to assign the environmental attributes associated with their generation to the utility for retirement. In addition, future policy design considerations in the coming year's Public Service Board process will likely incorporate discussion of the value and ownership of environmental attributes. For the purposes of this report, the Department has assumed a fixed value of $30/MWh in nominal terms, with a switch in the spreadsheet to turn this value on and off.

Ownership of Renewable Energy Credits ("RECs") conveys upon the owner the right to claim the use of renewable energy. If a net metered customer retains their RECs, they may claim that the load served by their utility account is in some or whole part renewable. If a customer transfers their RECs to their utility under Act 99 for retirement on their behalf, they may make the same claim. However, if a customer transfers the RECs to a third party, then the customer may no longer make that claim. There is potential future regulatory value in REC retirement to utilities, if Vermont were to adopt a renewable portfolio standard that used RECs as a compliance mechanism. Vermont may only claim environmental benefits of net metering projects (e.g. avoided greenhouse gas emissions) toward state targets if RECs are retained or purchased for retirement in Vermont.

3.2.1.2.7 Climate change

The Department's analysis calculates the costs and benefits of net metering to the state's non-participating ratepayers both with and without the estimated externalized cost of greenhouse gas emissions. It should be noted that these benefits from a marginal net metering installation in Vermont do not flow to Vermonter ratepayers in direct monetary terms. Instead, they reflect both a societal cost that is avoided and the size of potential risk that Vermont ratepayers avoid by reducing greenhouse gas emissions. If these environmental costs were fully internalized, for example into the cost of energy, ratepayers would bear those costs. The Department is assuming a value of $100 per metric ton of CO_2 emissions reduced (in $2013); this is the societal value adopted by the Public Service Board for use in energy efficiency screening, and is intended to reflect the marginal cost of abatement. About $5, rising to approximately $10, of the $100/ton is internalized in forecasted energy costs through the Regional Greenhouse Gas Initiative, so the analysis incorporates an additional cost of about $90-95 (in $2013) for cases in which costs of environmental externalities are included.

CO_2 emission reductions are calculated by using the 2012 ISO-New England marginal emission rate of 854 lbs/MWh.[4] ISO-NE grid operations and markets almost always result in a gas generator dispatched as the marginal plant, so this value is comparable to the emissions from a natural gas generator. The Department's analysis does not track or account for emissions or abatement of other greenhouse gasses.

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[4] http://www.iso-ne.com/static-assets/documents/genrtion_resrcs/reports/emission/2012_emissions_report_final_v2.pdf

3.3 Results of Cross-Subsidization Analysis

3.3.1 Systems Examined

This report presents the results of the cross-subsidization analysis for 6 systems:

- A 4 kW fixed solar PV system, net metered by a single residence;
- A 4 kW 2-axis tracking solar PV system, net metered by a single residence;
- A 4 kW wind generator, net metered by a single residence;
- A 100 kW fixed solar PV system, net metered by a group;
- A 100 kW 2-axis tracking solar PV system, net metered by a group; and
- A 100 kW wind generator, net metered by a group.

3.3.2 Results for Systems Installed in 2015

The methodology described in section 3.2 allows the model to calculate costs incurred and benefits received from each typical net-metered generator on an annual basis. These values may also be combined into a 20-year levelized value. A levelized value is the constant value per kWh generated that has the same present value as the projected string of costs and/or benefits over the 20-year study period. This section presents graphs of the statewide average annual costs and benefits along with levelized costs, benefits, and net costs (costs minus benefits). The graphs presented below depict the ratepayer perspective.[5] The tables are presented for net benefits for both the ratepayer and a statewide/societal perspective.[6] For each system we separately present the ratepayer-perspective numbers for each utility.

[5] The ratepayer perspective calculation uses the higher discount rate (7.44%) and includes a REC value. RECs were assumed to have a fixed value of $30/MWh, so the reader may adjust for a no-REC-value case by subtracting 3 cents ($0.03) from the benefits values.

[6] The statewide/societal calculation uses a lower discount rate (4.95%), includes avoided externalized GHG costs and does not include a REC value. We have selected a "parochial" version of society which counts avoided RNS costs and Vermont-specific market price suppression; each of these involve transfers between Vermont and other New England states and might not be included in a societal test with a broader perspective.

3.3.2.1 4 kW fixed solar PV system, net metered by a single residence

A 4 kW fixed solar PV system would generate about nearly 5,000 kWh annually with a capacity factor of 14.2%.

Exhibit 9. *Per-kWh costs (red line) and benefits (colored areas) for a 4 kW fixed solar PV system installed in 2015, from a ratepayer perspective.*

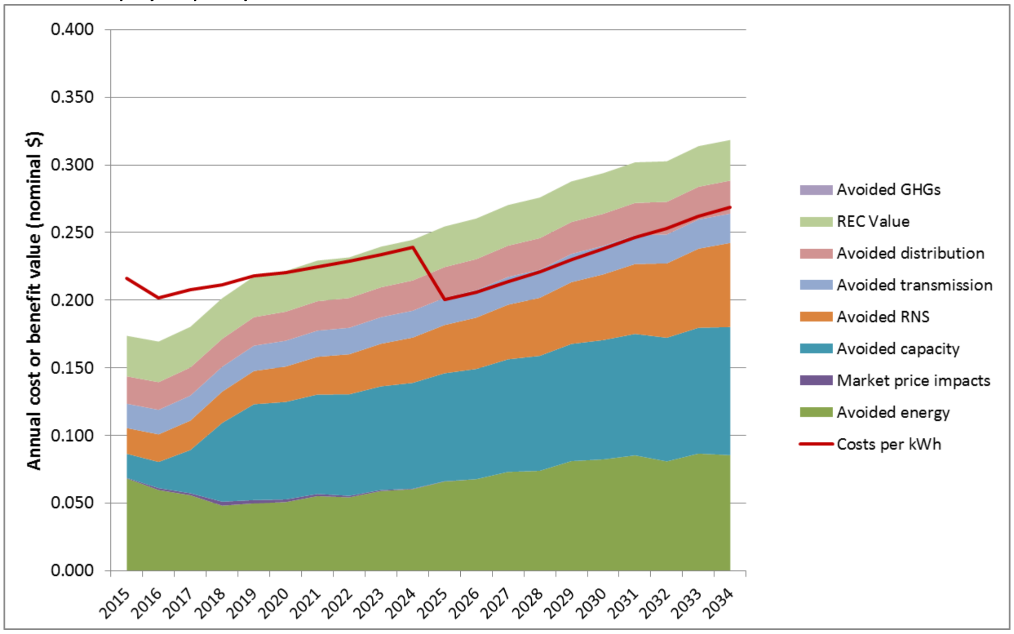

Exhibit 10. *Levelized cost, benefit, and net benefit of a 4 kW fixed solar PV residential system installed in 2015 to other ratepayers or society. Units are $ per kWh generated.*

	Cost	Benefit	Net Benefit
Ratepayer	$0.229	$0.237	$0.009
Statewide/Society	$0.230	$0.256	$0.026

Exhibit 11. *Levelized cost, benefit, and net benefit of a 4 kW fixed solar PV residential system installed in 2015 to other ratepayers, by utility. Refer to Section 3.2 for a description of why these values vary by utility. Units are $ per kWh generated.*

Utility	Cost	Benefit	Net Benefit
Barton	$0.229	$0.217	($0.011)
BED	$0.224	$0.215	($0.010)
Enosburg	$0.229	$0.231	$0.002
GMP	$0.226	$0.237	$0.011
Hardwick	$0.232	$0.216	($0.017)
Hyde Park	$0.232	$0.221	($0.011)
Jacksonville	$0.227	$0.229	$0.003
Johnson	$0.231	$0.237	$0.006
Ludlow	$0.206	$0.223	$0.017
Lyndonville	$0.221	$0.228	$0.006
Morrisville	$0.225	$0.244	$0.019
Northfield	$0.217	$0.220	$0.003
Orleans	$0.212	$0.241	$0.030
Stowe	$0.236	$0.225	($0.011)
Swanton	$0.207	$0.246	$0.039
VEC	$0.233	$0.218	($0.014)
WEC[7]	$0.197	$0.215	$0.017

[7] Due to its unique program, WEC's costs and benefits depend on the fraction of the customer's use that is offset by the net metered system. For this and each other example system, the Department assigned the household a usage comparable to the average residential energy use among WEC members.

3.3.2.2 4 kW tracking solar PV system, net metered by a single residence

A 4 kW 2-axis tracking solar PV system would generate about 6,600 kWh annually with a capacity factor of 18.8%.

Exhibit 12. *Per-kWh costs (red line) and benefits (colored areas) for a 4 kW 2-axis tracking solar PV system installed in 2015, from a ratepayer perspective.*

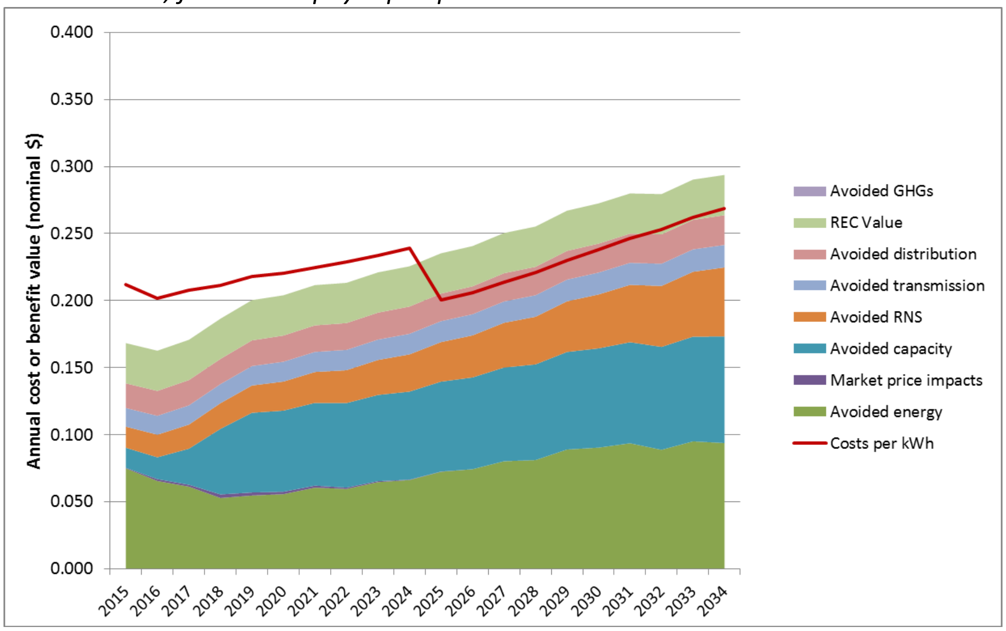

Exhibit 13. *Levelized cost, benefit, and net benefit of a 4 kW 2-axis tracking solar PV residential system installed in 2015 to other ratepayers or society. Units are $ per kWh generated.*

	Cost	Benefit	Net Benefit
Ratepayer	$0.228	$0.221	($0.007)
Statewide/Society	$0.229	$0.238	$0.009

Exhibit 14. *Levelized cost, benefit, and net benefit of a 4 kW 2-axis tracking solar PV residential system installed in 2015 to other ratepayers, by utility. Refer to Section 3.2 for a description of why these values vary by utility. Units are $ per kWh generated.*

Utility	Cost	Benefit	Net Benefit
Barton	$0.228	$0.205	($0.023)
BED	$0.224	$0.200	($0.024)
Enosburg	$0.229	$0.216	($0.013)
GMP	$0.225	$0.220	($0.005)
Hardwick	$0.232	$0.202	($0.030)
Hyde Park	$0.232	$0.204	($0.027)
Jacksonville	$0.227	$0.218	($0.009)
Johnson	$0.231	$0.224	($0.007)
Ludlow	$0.205	$0.208	$0.003
Lyndonville	$0.221	$0.215	($0.006)
Morrisville	$0.225	$0.224	($0.001)
Northfield	$0.217	$0.206	($0.011)
Orleans	$0.211	$0.229	$0.018
Stowe	$0.235	$0.212	($0.023)
Swanton	$0.207	$0.229	$0.022
VEC	$0.232	$0.207	($0.025)
WEC	$0.187	$0.201	$0.014

3.3.2.3 4 kW wind generator, net metered by a single residence

A 4 kW wind generator generates approximately 3,400 kWh per year, with a capacity factor of 9.6%. If such a generator were sited optimally, it could have a higher capacity factor and generate more electricity. However, the per-kWh costs and benefits described here would be unlikely to change significantly.

Exhibit 15. *Per-kWh costs (red line) and benefits (colored areas) for a 4 kW wing generator installed in 2015, from a ratepayer perspective.*

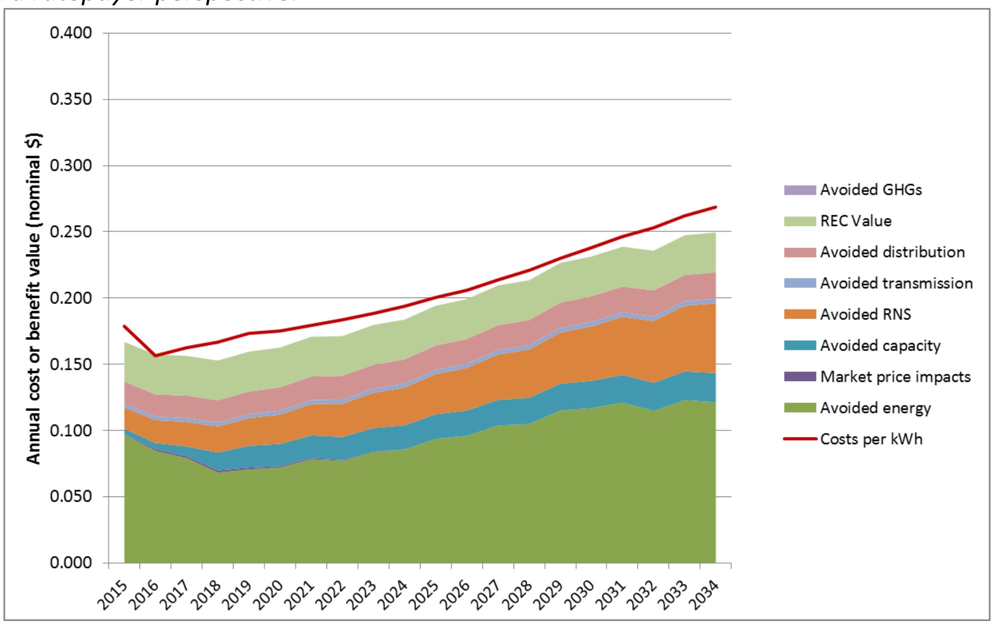

Exhibit 16. *Levelized cost, benefit, and net benefit of a 4kW wind generator installed in 2015 to other ratepayers or society. Units are $ per kWh generated.*

	Cost	Benefit	Net Benefit
Ratepayer	$0.198	$0.188	($0.009)
Statewide/Society	$0.201	$0.204	$0.003

Exhibit 17. *Levelized cost, benefit, and net benefit of a 100kW wind generator installed in 2015 to other ratepayers, by utility. Refer to Section 3.2 for a description of why these values vary by utility. Units are $ per kWh generated.*

Utility	Cost	Benefit	Net Benefit
Barton	$0.197	$0.196	($0.001)
BED	$0.187	$0.170	($0.017)
Enosburg	$0.198	$0.184	($0.014)
GMP	$0.194	$0.187	($0.007)
Hardwick	$0.207	$0.199	($0.008)
Hyde Park	$0.206	$0.200	($0.006)
Jacksonville	$0.193	$0.193	($0.000)
Johnson	$0.203	$0.191	($0.012)
Ludlow	$0.141	$0.192	$0.051
Lyndonville	$0.180	$0.191	$0.012
Morrisville	$0.189	$0.185	($0.004)
Northfield	$0.169	$0.194	$0.025
Orleans	$0.155	$0.187	$0.032
Stowe	$0.215	$0.189	($0.026)
Swanton	$0.144	$0.187	$0.043
VEC	$0.207	$0.197	($0.011)
WEC	$0.219	$0.199	($0.020)

3.3.2.4 100 kW fixed solar PV system, group net metered

A 100 kW fixed solar PV system would generate about 125,000 kWh annually with a capacity factor of 14.2%.

Exhibit 18. *Per-kWh costs (red line) and benefits (colored areas) for a 100kW fixed solar PV system, group net metered, installed in 2015, from a ratepayer perspective.*

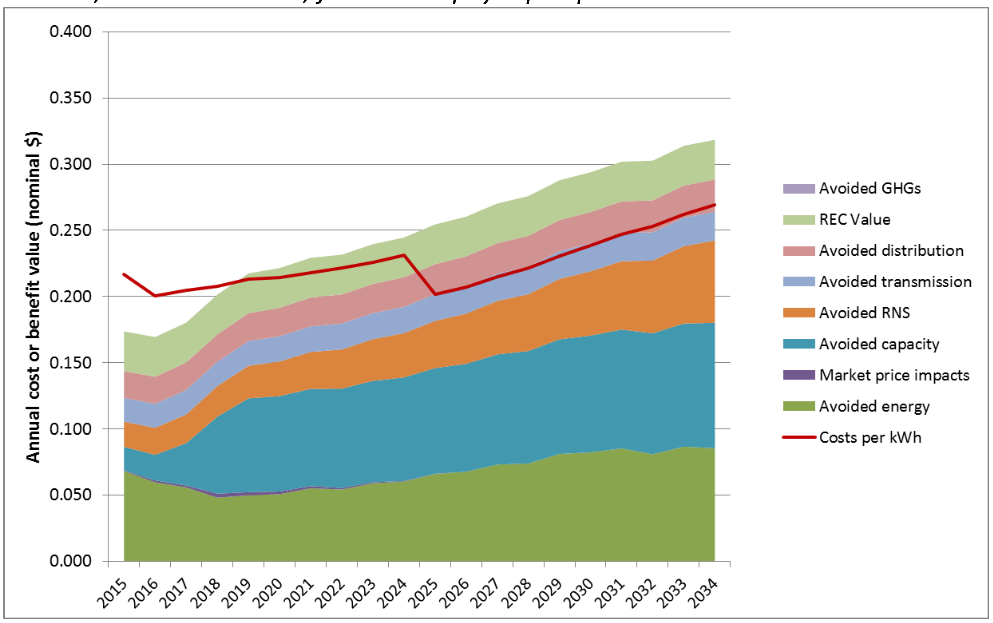

Exhibit 19. *Levelized cost, benefit, and net benefit of a 100kW fixed solar PV system, group net metered, installed in 2015 to other ratepayers or society. Units are $ per kWh generated.*

	Cost	Benefit	Net Benefit
Ratepayer	$0.226	$0.237	$0.011
Statewide/Society	$0.227	$0.256	$0.028

Exhibit 20. *Levelized cost, benefit, and net benefit of a 100kW fixed solar PV system, group net metered, installed in 2015 to other ratepayers, by utility. Refer to Section 3.2 for a description of why these values vary by utility. Units are $ per kWh generated*

Utility	Cost	Benefit	Net Benefit
Barton	$0.226	$0.217	($0.009)
BED	$0.222	$0.215	($0.007)
Enosburg	$0.226	$0.231	$0.005
GMP	$0.223	$0.237	$0.014
Hardwick	$0.230	$0.216	($0.014)
Hyde Park	$0.230	$0.221	($0.008)
Jacksonville	$0.224	$0.229	$0.005
Johnson	$0.228	$0.237	$0.009
Ludlow	$0.203	$0.223	$0.020
Lyndonville	$0.219	$0.228	$0.009
Morrisville	$0.223	$0.244	$0.021
Northfield	$0.215	$0.220	$0.006
Orleans	$0.209	$0.241	$0.032
Stowe	$0.233	$0.225	($0.008)
Swanton	$0.204	$0.246	$0.041
VEC	$0.230	$0.218	($0.012)
WEC	$0.212	$0.215	$0.002

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3.3.2.5 100 kW tracking solar PV system, group net metered

A 100 kW 2-axis tracking solar PV system would generate about 165,000 kWh annually with a capacity factor of 18.8%.

Exhibit 21. *Per-kWh costs (red line) and benefits (colored areas) for a 100kW 2-axis tracking solar PV system, group net metered, installed in 2015, from a ratepayer perspective.*

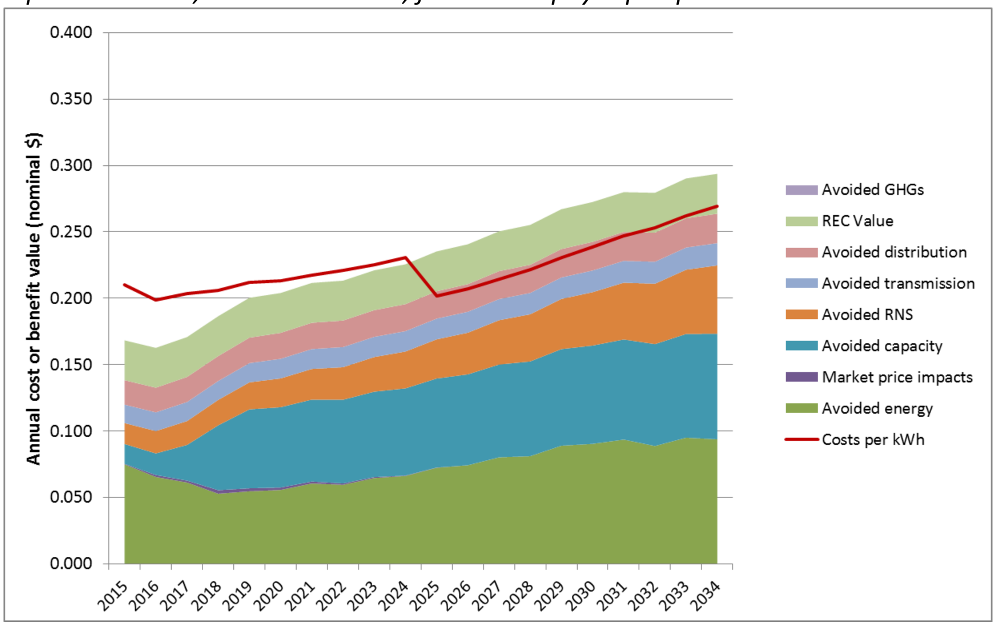

Exhibit 22. *Levelized cost, benefit, and net benefit of a 100kW 2 axis tracking solar PV system, group net metered, installed in 2015 to other ratepayers or society. Units are $ per kWh generated.*

	Cost	Benefit	Net Benefit
Ratepayer	$0.225	$0.221	($0.004)
Statewide/Society	$0.226	$0.238	$0.012

Exhibit 23. *Levelized cost, benefit, and net benefit of a 100kW 2 axis tracking solar PV system, group net metered, installed in 2015 to other ratepayers, by utility. Refer to Section 3.2 for a description of why these values vary by utility. Units are $ per kWh generated.*

Utility	Cost	Benefit	Net Benefit
Barton	$0.225	$0.205	($0.019)
BED	$0.220	$0.200	($0.020)
Enosburg	$0.225	$0.216	($0.009)
GMP	$0.222	$0.220	($0.001)
Hardwick	$0.228	$0.202	($0.026)
Hyde Park	$0.228	$0.204	($0.024)
Jacksonville	$0.223	$0.218	($0.005)
Johnson	$0.227	$0.224	($0.003)
Ludlow	$0.202	$0.208	$0.007
Lyndonville	$0.217	$0.215	($0.002)
Morrisville	$0.221	$0.224	$0.003
Northfield	$0.213	$0.206	($0.007)
Orleans	$0.207	$0.229	$0.022
Stowe	$0.232	$0.212	($0.020)
Swanton	$0.203	$0.229	$0.026
VEC	$0.228	$0.207	($0.022)
WEC	$0.206	$0.201	($0.006)

3.3.2.6 100 kW wind generator, group net metered

A 100 kW wind generator generates approximately 84,000 kWh per year, with a capacity factor of 9.6%. If such a generator were sited optimally, it could have a significantly higher capacity factor and generate more electricity. However, the per-kWh costs and benefits described here would be unlikely to change significantly.

Exhibit 24. *Per-kWh costs (red line) and benefits (colored areas) for a 100kW wind generator, group net metered, installed in 2015, from a ratepayer perspective.*

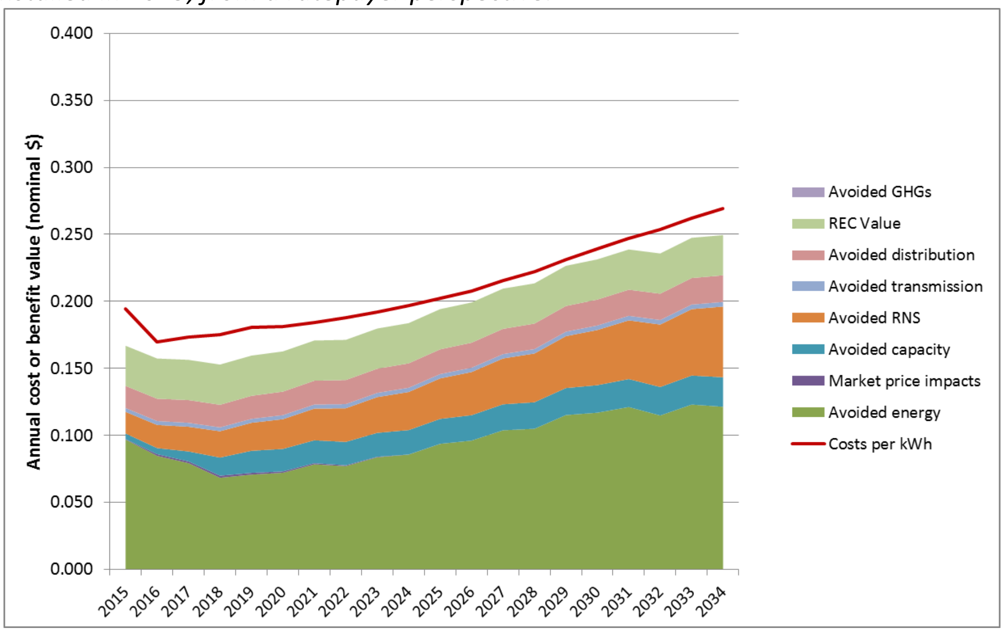

Exhibit 25. *Levelized cost, benefit, and net benefit of a 100kW wind generator, group net metered, installed in 2015 to other ratepayers or society. Units are $ per kWh generated.*

	Cost	Benefit	Net Benefit
Ratepayer	$0.204	$0.188	($0.016)
Statewide/Society	$0.207	$0.204	($0.003)

Exhibit 26. *Levelized cost, benefit, and net benefit of a 100kW wind generator, group net metered, installed in 2015 to other ratepayers, by utility. Refer to Section 3.2 for a description of why these values vary by utility. Units are $ per kWh generated.*

Utility	Cost	Benefit	Net Benefit
Barton	$0.204	$0.196	($0.008)
BED	$0.193	$0.170	($0.024)
Enosburg	$0.205	$0.184	($0.020)
GMP	$0.200	$0.187	($0.013)
Hardwick	$0.213	$0.199	($0.015)
Hyde Park	$0.213	$0.200	($0.012)
Jacksonville	$0.200	$0.193	($0.007)
Johnson	$0.209	$0.191	($0.019)
Ludlow	$0.147	$0.192	$0.044
Lyndonville	$0.186	$0.191	$0.005
Morrisville	$0.195	$0.185	($0.010)
Northfield	$0.175	$0.194	$0.019
Orleans	$0.162	$0.187	$0.026
Stowe	$0.221	$0.189	($0.033)
Swanton	$0.150	$0.187	$0.036
VEC	$0.214	$0.197	($0.017)
WEC	$0.213	$0.199	($0.015)

3.3.3 Concluding Remarks on Cross-Subsidization

The analysis presented in the preceding sections indicates that the aggregate net cost over 20 years to non-participating ratepayers due to net metering under the current policy framework is close to zero, and there may be a net benefit. Analysis of the differences between utilities indicates that winter-peaking utilities, which see fewer benefits from net metered solar PV, will incur a larger share of the net cost than summer peaking utilities or those utilities with lower retail rates. As such, for the post-2016 period, the Department recommends that the Board consider whether or not changes to the current program structure to allow flexibility for the program to vary by utility would better serve the state.

It is appropriate to note that cross-subsidies are common in utility ratemaking. While rates strive to assign costs to those who cause them, this cannot be done exactly. The classic example is the comparison of urban and rural rates – the rural ratepayers have caused the construction of an extensive distribution system, form which the urban customers do not directly benefit, yet all pay equally for distribution network costs. This challenge is a portion of why rural electrification required explicit government action in the early part of the last century. Society as a whole has benefited from universal electrification, and concern about this cross-subsidy has generally faded. While policymakers can strive to minimize cross-subsidization in the net metering context, a precise elimination is unlikely and would hold net metering policies to a higher standard than that achieved by other ratemaking.

Net benefits from net metering systems, are either positive or negative depending on the details of utility rate structures, benefits from avoided distribution infrastructure, and the inclusion or exclusion of the value of renewable energy and greenhouse gas emission reductions. Notably, wind net metered systems performed much better in the model based on 2013-14 data than it did for the previous Act 125 model. This is largely due to wind's operation more often during the recent high prices for energy in the winter, and the more comprehensive treatment of winter distribution peaks in this report. As such, small wind as modeled performs even better for some utilities whose peak demand is during dark, winter hours. On the other hand, solar PV has much greater coincidence of generation with times of regional and some local peak demand than does wind power. This phenomenon underscores the year-to year, and utility-to-utility, variability associated with the benefits from net metering technology. It will be important to consider this variability in considering program design, but as described further below (see Section 4), designing a program with stability in mind can mitigate single year price and value volatility. Further, structures could be considered that incent technologies to be developed and/or sited in ways that focus on peak benefits – whether they relate to energy and capacity prices or a utility's peak demand.

The Department suggests that there is value in having a common methodology for the quantification of the value of distributed generation (represented in the benefits side of the above calculations). This will allow interested parties to identify areas of agreement and disagreement on the value of DG resources, and potentially reach consensus regarding assumptions. To that end, the Department has made the spreadsheets used to calculate all of the results presented here publicly available. There need not be a direct link between the value provided by DG resources and the amount or form of compensation provided through a net metering program – Vermont's current policy approaches a lack of cross-subsidy while not explicitly linking compensation to benefits. It may be that in order to achieve long-term objectives for DG deployment, compensation needs to be above value provided for particular technologies or particular time-periods – such compensation above value could be delivered through a net metering tariff, or through alternate incentives structures, and may depend on the availability and structure of funding.

4 Lesson learned for net metering identified from other states

While Act 99 requires that the Department address "best practices" from other jurisdictions, our review of the literature and the current state of distributed generation regulation across the country indicates that it is premature to identify "best practices." Instead, this section identifies lessons learned from other jurisdictions and describes "guiding principles" published in recent literature and offered for consideration here.

4.1 Literature review

The 2013 *Freeing the Grid*[8] report from the Interstate Renewable Energy Council and the Vote Solar Initiative provides a good summary of the nation's net metering policies; an independent catalog of the range of existing net metering policies was not completed for this report. Instead, this section of the report will summarize two key reports, one from the National Renewable Energy Laboratory ("NREL", with assistance from the Regulatory Assistance Project, "RAP") and the other from RAP, which provide both overview and detail on regulatory options for addressing high penetrations of distributed generation (particularly solar). Together, they provide a framework for Vermont to evaluate existing and potential tools to expand or modify our net metering program, drawn from lessons learned across the country.

[8] Barnes, J., Culley, T., Haynes, R., Passera, L., Wiedman, J., and Jackson, R. (2013). Freeing the Grid: Best Practices in State Net Metering Policies and Interconnection Procedures. New York, NY and San Francisco, CA. Interstate Renewable Energy Council and The Vote Solar Initiative. Retrieved from http://freeingthegrid.org/wp-content/uploads/2013/11/FTG_2013.pdf.

4.1.1 "Regulatory Considerations Associated with the Expanded Adoption of Distributed Solar"

In their November 2013 technical report, *Regulatory Considerations Associated with the Expanded Adoption of Distributed Solar*,[9] NREL and RAP provide a useful primer on the range of issues – from cost-benefit analyses to business models and ratemaking options – that regulators should consider when undertaking redesign of mechanisms to accommodate increasing penetrations of distributed solar. The authors recommend that regulators borrow methods learned from energy efficiency program design and regulation in order to address increased distributed solar, or even seek to simultaneously address issues related to distributed generation (DG), demand side management, and energy efficiency in order to achieve optimal regulatory and rate-making solutions.

The authors refrain from advocating any particular tool or combination of tools, stress that there is no one-size-fits all solution, and posit that new regulatory tools or combinations of existing tools will emerge as regulators begin to address the increasing pace of distributed solar deployment happening across the U.S. They suggest the optimal solution will make sense at any scale of solar deployment, rendering revisions and exceptions unnecessary; but if that should prove an impossible task, then regulators should at least anticipate high penetration levels and set in motion a transparent, predictable process to design tariffs that will address those levels.

The study discusses ratemaking options, spanning the universe of existing tools employed by regulators to accommodate distributed solar. They are framed in terms of performance, limits and downsides, and relevant utility type (i.e. investor-owned, cooperative, municipal) and include: net metering, fixed charges, stand-by rates, time-based pricing, two-way rates, minimum monthly billing, and creation of a new customer class for photovoltaic customers. Helpful case studies of places where these various tools are being deployed are included (e.g., implementation of a value of solar tariff – a type of two-way rate – in Minnesota). Notably, the report provides a list of "Questions for Framing the Regulatory Discussion." These questions are attached to this report as an appendix in recognition of its wholesale value to the present discussion.

The authors place emphasis throughout the paper on the various avenues by which regulators can influence the actions of utilities and – consequentially – the climate for solar deployment within a state. One option they discuss is for regulators and utilities to consider strategically placed distributed solar in the resource planning process, as one among a suite of potential least cost options to increase system reliability. The Vermont System Planning Committee (VSPC) serves as a venue today for discussions of utility infrastructure planning; the VSPC plays a role in the identification of constrained areas where DG could provide "sufficient benefit" in the context of the Standard Offer program and in the incorporation of DG into load forecasts.

Finally, the authors point to gaps in the knowledge base that need to be addressed in order for regulators to make informed decisions, such as the benefits and costs of distributed solar at high penetration levels, and the changes in cost-of-service figures and utility financials that will inevitably transpire if and when high penetrations of distributed solar are achieved. As noted in section 5.4, Vermont may be reaching these high penetrations of distributed solar sooner rather than later.

[9] Bird, L., Mclaren, J., Heeter, J., Linvill, C., Shenot, J., Sedano, R., & Migden-Ostrander, J. (2013). Regulatory Considerations Associated with the Expanded Adoption of Distributed Solar (NREL/TP-6A20-60613). Golden, CO: National Renewable Energy Laboratory. Retrieved from http://www.nrel.gov/docs/fy14osti/60613.pdf.

4.1.2 "Designing Distributed Generation Tariffs Well"

In their 2013 paper, *Designing Distributed Generation Tariffs Well*,[10] the Regulatory Assistance Project focuses specifically on the design of tariffs that fairly compensate both customer-sited DG resources as well as utility services to customers. They note the importance of other regulatory tools to accommodate solar and distributed resources, such as those mentioned in the NREL paper discussed above, but focus on a discussion of tariffs and specifically advocate for two-way distribution tariffs, where both generators and utilities are fairly and accurately compensated for the specific services provided.

The authors are quick to acknowledge barriers to enacting perfect tariffs, such as immaturity of hardware and information technologies as well as legacy imperfections built into retail rate design, but stress the importance of improving upon existing compensation mechanisms in a way that moves toward greater fairness and accuracy while setting the stage for an easy transition to more sophisticated mechanisms (i.e. a transactive energy economy, where multiple parties including utilities, distributed generators, and aggregators are fairly and accurately compensated for the services provided) as technologies and markets evolve.

The RAP highlights that keeping tariffs simple and practical – as advocated by Bonbright[11] – is especially important in examining replacements for relatively well understood tools such as net metering. Beyond that, they then consider whether a serious cross-subsidy problem actually exists; and, if so, which tariff and rate design approaches might address the cross-subsidy. Finally, they propose to solve any remaining sources of stakeholder conflict with additional regulatory treatment (e.g. decoupling).

The RAP report examines issues important for consideration by regulators as they evaluate benefits, costs, and net value of DG to various stakeholders (DG adopters, non-adopter ratepayers, utilities, and society more broadly) as part of the tariff design process. This includes a discussion of sources of mutual benefit and sources of conflict among stakeholder value propositions drawn from examples in various states and jurisdictions. The report considers rate design options and alternative ratemaking approaches for fairly reconciling the needs and perspectives of various stakeholders. The options examined (through the lens of Bonbright's "Principles of Public Utility Rates," also discussed in the NREL paper) include: enacting a fixed charge for distribution costs; imposing a demand charge-based distribution charge and time-of-use (TOU) rate; and implementing a bidirectional distribution rate. (A different take on these approaches is illustrated in Exhibit 27 below.) The impacts of these various approaches on

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[10] Linvill, C., Shenot, J., and Lazar, J. (2013). Designing Distributed Generation Tariffs Well: Fair Compensation in a Time of Transition. Montpelier, VT: The Regulatory Assistance Project. Retrieved from http://www.raponline.org/document/download/id/6898.

[11] Bonbright, J.C. (1961). Principles of Public Utility Rates. New York, NY: Utilities Reports, Inc. & Columbia University Press. The principles, as summarized in the RAP paper, include:

- Tariffs should be practical: simple, understandable, acceptable to the public, feasible to apply, and free from controversy as to their interpretation.
- Tariffs should keep the utility viable, effectively yielding the total revenue requirement and resulting in relatively stable cash flow and revenues from year to year.
- Rates should be relatively stable such that customers experience only minimal unexpected changes that are seriously adverse.
- Tariffs should fairly apportion the utility's cost of service among consumers and should not unduly discriminate against any customer or group of customers.
- Tariffs should promote economic efficiency in the use of energy as well as competing products and services while ensuring the level of reliability desired by customers.

representative ratepayer groups – apartment dwellers, typical residences, large residences, and photovoltaic customers – are then examined.

The RAP authors suggest that today's tools – net metering and feed-in tariffs – may achieve simplicity (per Bonbright) but fall short on precision (per a transactive energy economy). However, they offer suggestions for "Getting NEM and FIT Right" in the meantime.

For net metering, these include: recognizing the premium value of renewable resources, which may justify full retail rate value; avoiding fixed monthly customer charges, which tend to penalize apartment dwellers and urban residents; and considering time-of-use arrangements in tariffs to encourage prices that are closer to the value of power consumed.

For feed-in-tariffs, suggestions include: providing stable and long terms (of at least ten years); allowing for different types of resources that offer unique attributes; considering auctions; committing to a stable policy that still allows for reasonable modification of prices and terms; and making sure program caps are not unreasonably restrictive.

Finally, the RAP authors provide 12 specific recommendations for regulators, reproduced here (additional detail on each is provided in the paper's conclusion):

1. Recognize that value is a two way street.
2. Distributed generation should be compensated at levels that reflect all components of relevant value over the long term.
3. Select and implement a valuation methodology.
4. Remember that cross-subsidies may flow to or from DG owners.
5. Don't extrapolate from anomalous situations.
6. Infant-industry subsidies are a long tradition.
7. Remember that interconnection rules and other terms of service matter.
8. Tariffs should be no more complicated than necessary.
9. Support innovative business models and delivery mechanisms for DG.
10. Keep the discussion of incentives separate from rate design.
11. Keep any discussion of the throughput incentive separate.
12. Consider mechanisms for benefitting "have not" consumers.

4.2 Literature review insights

There are a number of options for the future design of net metering in Vermont. Exhibit 27 highlights a range of possible models for the evolution of net metering in different jurisdictions. Reformed net metering programs (those, like Vermont's, that go beyond simple "spin the meter backward" net metering) can be divided into those which retain a single-rate approach, but reform some piece of that rate (e.g. a fixed charge, demand charge, or other solar charge), and those which use more than one rate (such as a solar value rate). As can be seen, program attributes vary by approach.

	CAMP 1	CAMP 2				
	Continue NEM	Reforming the Solar Customer Transaction (NEM reform)				
RATE CONSTRUCT	Single Transaction (Rate) Approach				Two or More Transactions (Rates)	
	Apply NEM	Reform Existing Rates (all customers or solar only)			Solar Rate	Reform All Rates
MODEL	Current Rates	Increased Fixed Charge and/or Minimum Bill	Demand Charge	Stand-by or Solar Charge	Independent Energy Sale and Solar Purchase Rates	Value of Services
ATTRIBUTES	• Currently applicable rates result in an acceptable transaction • Solar penetration does not warrant action	• Add or increase basic service charge ($/month) • Raise min bill requirements ($/month)	• Add or increase customer fee for demand ($/kW/month)	• Charge for stand-by capacity, based on DG system size ($/kW/month or ($/kW/yr)	• Retain existing rates for services provided from utility to cust. • Establish second rate to purchase from customer	• Design rates to reflect itemized services from utility to cust. and from cust. to utility

Exhibit 27. *Summary table of rate structure options for net metering, including options that use one rate and include specific charges and options that use more than one rate. Figure courtesy of Julia Hamm, Solar Electric Power Association.*[12]

In addition to the guiding principles articulated by NREL and RAP, there are other considerations that will affect the success of any redesigned net metering program. For instance, the numerous changes in Vermont net metering statutes over the last decade have highlighted the value of stability in policy and financial programs. This stability allows time for the market to understand and respond to policy goals without the fear of potential swift program changes that might deter innovative solutions. Another consideration should be the value of price certainty for investors; a reasonably predictable credit for generation may allow for more accessible financing of small generation.

It is important to note that the pace of deployment doesn't necessarily only depend on net metering program tariff design. Other, complementary efforts such as tax policy or separate incentive funding mechanisms should be considered in the upcoming process.

The RAP and NREL reports clearly articulate that there is no "best practice" which Vermont can simply emulate; there is no "one size fits all" policy framework that can simply be adopted. Instead, the design of future programs must begin with a critical review of the pertinent issues relevant to Vermont stakeholders to determine feasible options and make informed decisions. While it is unlikely that a perfect tariff could be established that equally addresses concerns of ratepayers and developers (including both home and business owners) installing net metered distributed generation across all of Vermont's utilities, striking the appropriate balance between potentially competing interests will help determine the success of the future of net metering in Vermont.

[12] Originally presented at the RPS Collaborative Summit, September 23, 2014. Reproduced with permission.

5 Other topics required by Act 99

5.1 Economic and environmental benefits of net metering

The cost and benefit discussion in Section 3 above describes the economic and environmental costs and benefits of net metering that are quantifiable on a per-kWh or per-kW basis. In addition to these costs and benefits, there are impacts which are hander to quantify on that basis. These include the direct employment of Vermonters in the design, permitting, construction, and operation of net metered generators. The Solar Foundation has identified that Vermont has the most solar jobs per capita of any state in the country. These jobs are to some large part a result of the state's aggressive adoption of net metered solar PV generation. In addition, the recent Clean Energy Development Fund *Clean Energy Industry Report*, which surveyed clean energy firms around the state, estimates that over 1,500 Vermonters work in the solar industry in some fashion, the greatest of any renewable energy technology. Maintaining a sustainable economic sector that develops clean energy resources is also a component of the state's recent Comprehensive Economic Development Strategy. The Department did not attempt to quantify these types of benefits in the analysis presented in Section 3; however the spreadsheet model offers the opportunity to add, on a per kWh basis, such values to the benefit of net metered technologies.

The Department considered attempting to quantify the reductions in air pollutants other than carbon dioxide due to net metering, but initial evaluation indicated there is significant uncertainty in the valuation of such emission reductions, and that the values are likely to be comparatively small regardless.[13]

5.2 Reliability and supply diversification costs and benefits

The benefit discussion in Section 3.2 above describes the reliability benefits that can occur due to net metered generators which reduce stress on the transmission and distribution grids during peak hours. At greater levels of deployment on particular circuits, net metered generators could result in "reverse" flows on energy on electric circuits not designed for those flows; equipment upgrades may be required at that point in order to maintain reliability.

Vermont has long valued diversification in its electric energy supply portfolio. For example, extensive dependence on any one fuel, such as oil, coal, nuclear, biomass, or natural gas, can leave ratepayers at risk that increases in the cost of that fuel would result in rate spikes. Vermont utilities have pursued a policy of constructing their portfolios with a substantial fraction made up from contracts for or ownership of different types of generation, and with fixed prices, known price escalation (e.g. with inflation), or prices with "collars" that prevent or dampen spikes. This has served a purpose of maintaining stable rates, leading to predictability for business and household costs. (The downside is that Vermont has not benefitted when one fuel or another falls sharply in price.) Many renewable generators for which there is no direct fuel cost (e.g. solar, wind, and hydroelectric) have economic structures that are fundamentally compatible with this desire for rate stability.

The benefits for rate stability of this sort that flow from net metering programs depend on the structure whereby participating customers are credited by their utility for their generation. Under a feed-in-tariff model or other fixed price arrangement between customer and utility, other ratepayers benefit from

[13] For example, the ISO-NE marginal emissions rate of NO_x was 0.22 lb/MWh in 2012. A rooftop solar PV system might generate 5 MWh/year, and avoid 1.1 lb. of NO_x emissions. Recent Federal rulemakings value NO_x emission reductions at between $476 and $4,893 per ton, or a maximum of less than $2.50 per pound.

price stability. A retail rate based structure has somewhat more risk, but retail rates are generally relatively smoothly increasing (historically roughly in line with overall inflation in Vermont), due to the many components that comprise a utility's cost of service. The lack of fuel price volatility makes most renewable net metered generators a good fit (in this respect) for Vermont utility portfolios.

5.3 Benefits to net metering customers of connecting to the distribution system

The analysis is Section 3 of this report discusses the costs and benefits of net metering form the utility or non-participating ratepayer point of view. Net metering also has costs and benefits from the standpoint of the participating net metered generator. Access to the electric distribution system, as opposed to being "off grid," allows a net metered customer to avoid the need to deploy energy storage, match supply and demand on-site, or use a diesel or other fuel-based generator. The grid also provides assurance of access to electrical power above that which and off-grid generator may provide. Use of a shared energy generation, transmission, and distribution infrastructure can be a societally least-cost way to meet energy service demand. Net metering customers benefit from the presence of the grid to transmit excess generation to other customers, and to draw upon at times when the net metered generator is not generating enough power to meet the customer's needs. "Virtual" group net metered customers use the distribution, and perhaps even the transmission, systems to connect the power generated by a remote generator to their account (although, as the name implies, this is done through accounting, rather than direct electrical flows).

5.4 The future pace of net metering deployment statewide and by utility

The Department recommends that Vermont ratepayers and utilities take maximum advantage of the current Federal tax incentive structure to build well-sited[14] distributed net metered generators, including solar PV, in the state between now and the end of 2016, when Federal tax treatment for solar PV may change. The design of a future net metering system for the time after 2016, which is the subject of the Public Service Board investigation to follow submission of this report, should be sensitive to the impact of Federal incentive policy. The investigation should also be informed by the amount of distributed solar PV and other generation built in the state and in each utility's service territory by the end of 2016. The Department therefore recommends that the Board take a relatively flexible approach to the setting of any targets for the pace of future deployment.

It is likely that the solar PV industry in Vermont and around the country will see a boom from now until the end of 2016. The economic activity and jobs associated with that boom will boost the clean energy sector in Vermont. Once Federal tax treatment changes, however, the industry will be at risk of a significant drop in activity, with associated economic hardship for particular firms and their employees. If this bust is sharp and deep, it may hamper the industry's ability to rebound, and thus the state's ability to meet long-term renewable energy goals. To that end, stakeholders and the Public Service Board should consider industry impacts when evaluating the impacts of different policy options for the post-2016 period.

At the current pace of permit applications, it is possible that the total permitted net metering may approach 150 MW by the end of 2016. Combined with other distributed generators built under the Standard Offer program or under PPA or utility ownership, this could mean 250 MW or more solar PV permitted in the state. This will have noticeable impacts on the state's load shape, and the load shapes

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[14] Encouragement for generators sited on "ideal" locations such as brownfields, landfills, industrial parks, etc. may be an appropriate consideration for the upcoming Public Service Board process.

of each of the state's utilities. In particular, it may push all summer peaks to near or past sunset in the summer.[15] This would have a significant impact on the value delivered by solar PV in terms of avoided in-state transmission and distribution infrastructure, as well as RNS costs. A slower transition throughout New England may impact the ISO-NE peak, shifting it later in the day as well, which will impact the energy and capacity markets. One unknown facing future distributed generation deployment is the level of deployment at which reverse flows and other integration challenges, with associated costs, begin to appear on the grid.[16]

Taking into account the context described in the previous three paragraphs, the Department recommends that the Board and stakeholders strive for a sustained pace of deployment while avoiding market booms or busts. Given the roughly 20-25 year lifetime of most distributed generators, the expectation of continued technological progress and associated falling real prices, and the likely continued development in grid management systems and technologies (including energy storage), renewable energy deployment toward 2050 goals can afford to take a longer-term view. This should be balanced with a need to remain flexible in order to take full advantage of changes in technology, Federal programs and policies, and evolving business models. The Board, and state policymakers in general, should strive for policies that balance the costs and benefits of distributed generation, including net metered generation, remain flexible, and aim for overall targets regarding renewable electricity (such as those established in 30 VSA 8005a) and renewable energy in all sectors.

[15] Given this shift, it may be worthwhile to consider policies that incent developers to increase focus on peak benefits at some expense of energy generation. An inexact calculation of a west-facing solar PV system in the Department's cost-benefit model indicates that a west-facing fixed solar PV system might produce as much as 15% more value per kWh generated than a south-facing system.

[16] Reliability issues such as maintenance of voltage and frequency events, and potential for accelerated ramping potentially necessary to meet peak demand have been the subject of significant discussion at the ISO-NE Distributed Generation Forecast Working Group. Information is available at http://iso-ne.com/committees/planning/distributed-generation

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Appendix: "Questions for Framing the Regulatory Discussion"

An excerpt from *National Renewable Energy Laboratory's Regulatory Considerations Associated with the Expanded Adoption of Distributed Solar.* Bird et. al. November 2013.