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Public Service Commission

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Three Empire State Plaza, Albany, NY 12223-1350
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December 17, 2015

(Via email to secretary@dps.ny.gov)
Honorable Kathleen H. Burgess
Secretary to the Commission
New York State Public Service Commission
Three Empire State Plaza
Albany, New York 12223-1350

Re: Case 15-E-0703 – In the Matter of Performing a Study on the Economic and Environmental Benefits and Costs of Net Metering Pursuant to Public Service Law §66-n.

Dear Secretary Burgess:

On December 17, 2014, §66-n of the Public Service Law was enacted in Chapter 510 of the Laws of 2014. Section 66-n requires the Commission to publish a report related to the costs and benefits of net energy metering.

At the time of the enactment of Chapter 510, the New York State Energy and Research Development Authority (NYSERDA) had commenced a net metering study pursuant to the Commission's NY-Sun Order. NYSERDA, with the concurrence of Department of Public Service Staff (Staff), had engaged Energy & Environmental Economics (E3) to perform that study. With the enactment of PSL §66-n, Staff requested that NYSERDA incorporate the new statutory requirements into the ongoing work. The accompanying report is the product of that engagement, and satisfies the requirements of both the NY-Sun Order and §66-n.

Attached is the report prepared by E3 titled "The Costs and Benefits of Net Energy Metering in New York." The report focuses primarily on solar technology, which constitutes the large majority of net metering projects in New York State. It constructs a range of cost and benefit assumptions across several customer class groupings and analyzes them for all utilities.

During the year since the enactment of PSL §66-n, many related developments have occurred. The Commission's adoption of the Regulatory Policy Framework and Implementation Plan Order on February 26, 2015,[1] the issuance of the Staff White Paper on Ratemaking and Utility Business Models issued July 28, 2015 in Case 14-M-0101, and the Commission's October 16, 2015 order related to net metering caps,[2] collectively identify a wide range of issues directly affecting net metering, which require stakeholder input and further resolution by the Commission.

The E3 report specifically addresses the issues enumerated by the Legislature. Staff has been consulted regularly in the formation of the report and has reviewed it for consistency with the legislative requirement and for the reasonableness of its assumptions and conclusions. Staff has not asserted final positions and has not independently confirmed the underlying assumptions.

The report emphasizes that there are a number of uncertainties inherent in the assumptions required for such an analysis. The conclusions in the report are not presented as definitive answers but rather as a bounded range of reasonable scenarios.

Because of the ongoing closely related proceedings, no independent stakeholder review of this report has been conducted. Pursuant to the Commission's Interim Cap Order,[3] Staff has begun to develop a process that will include stakeholders in a comprehensive evaluation of the value of distributed resources (including those eligible for net metering). This report will serve as a data input to that effort. This process is expected to occur in 2016 and, per the Commission's order, should result in an interim valuation process being presented for adoption by the Commission no later than December 2016.

Very truly yours,

/S/

Scott Weiner, Deputy
Markets and Innovation

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1 Case 14-M-0101, Reforming the Energy Vision, Order Adopting Regulatory Policy Framework and Implementation Plan (issued February 26, 2015).

2 Case 15-E-0407, Orange and Rockland Utilities, Inc., Order Establishing Interim Ceilings on the Interconnection of Net Metered Generation (issued October 16, 2015) (Interim Cap Order).

3 Id. pp. 9-10

The Benefits and Costs of Net Energy Metering in New York

Prepared for: New York State Energy Research and Development Authority and New York State Department of Public Service

December 11, 2015

Energy+Environmental Economics

The Benefits and Costs of Net Energy Metering in New York:

Prepared for: New York State Energy Research and Development Authority and New York State Department of Public Service

December 11, 2015

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Executive Summary

ES.1. Introduction and Background

Energy and Environmental Economics, Inc. (E3 or "we") was retained by the New York State Energy and Research Development Authority (NYSERDA) to perform a study on the behalf of the Department of Public Service (DPS) in response to specific New York state legislation.[1] This study performs the following tasks as outlined by that legislation:

+ "Analyze the economic and environmental benefits[2] from and the economic cost burden, if any, of the net energy metering program."
+ "Analyze the extent to which ratepayers receiving service under the net energy metering program are paying the full cost of services provided to them by combined electric and gas corporations and gas corporations, and the extent to which their customers pay a share of costs of public purpose programs through assessments on their electric and/or gas bills."
+ "The study shall also quantify the economic costs and benefits of net energy metering to participants and non-participants and shall further disaggregate the results by utility."
+ "The study shall also gather and present data on the income distribution of residential net metering participants that is publicly available and aggregated by zip code and county."

[1] See the study Appendix or **http://open.nysenate.gov/legislation/bill/S5149A-2013**

[2] The legislation specifically states that "As it relates to the environmental benefits, the study shall quantify the approximate avoided level of harmful emissions including, but not limited to, information concerning: nitrogen dioxide, sulfur dioxide and carbon dioxide, as well as other air pollutants deemed necessary and appropriate for study by the commission."

ES.2. Methodology

E3 in consultation with a project management team made up of relevant staff at NYSERDA and DPS made several assumptions and analytical methodology choices in order to perform the specific tasks called for in the legislation. One of the major choices was to examine and analyze the current net metering policy without explicitly addressing community solar or remote net metering. These policies were in flux during the period that this study was being performed[3]. Another major choice was to focus the study on the benefits and costs of distributed solar photovoltaics (PV) as this technology constitutes the vast majority of net energy metered (NEM[4]) technologies currently installed, which is a trend that is expected to continue. That being said, the benefits and costs of other NEM-eligible technologies are also examined in this study and those results are presented.

An appropriate range of benefits and costs for net metered systems in New York is constructed and analyzed for all utilities[5] and three customer class groupings (residential, small non-residential, and large non-residential). This analysis is performed from **multiple** perspectives (i.e., participating NEM and non-participating ratepayers plus society) both now and in the future consistent with industry standard practices and the DPS Benefit-Cost Analysis (BCA) White Paper for evaluating distributed energy resource (DER) cost-effectiveness.[6] The methodology and analysis presented in this study are also compared to a number of other NEM or 'value of solar' studies nationwide for contextual purposes.

Further, it is worth noting that there are a number of uncertainties inherent in any assumption-driven and forward-looking analysis such as this and other similar types of studies that should be

[3] We do acknowledge that community solar and remote net metering can result in lower cost installations, which may result in lower total resource costs as compared to the benefits it offers to participants and society. This may result in this analysis being conservative with all else being equal if we are not fully capturing this effect. We also acknowledge that community net metering and remote net metering could accelerate adoption among certain customer segments so the market should be monitored for impact. Further, we do not address the Reforming the Energy Vision (REV) Proceeding which is ongoing and may result in changes to the current net metering policy and structure.

[4] When we refer to 'NEM' throughout this study such as "NEM installations" or "NEM generation" we mean net metered solar PV installations or generation unless otherwise explicitly stated.

[5] These are the six investor owned utilities in New York: Consolidated Edison Company of New York (ConEd), National Grid (Nat Grid or NiMo), New York State Electric and Gas (NYSEG), Rochester Gas and Electric (RG&E), Orange and Rockland Utilities (ORU), and Central Hudson Gas and Electric (CHG&E or Central Hudson) plus PSEG Long Island (LIPA).

[6] **http://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/26be8a93967e604785257cc40066b91a/$FILE/Staff_BCA_Whitepaper_Final.pdf**

considered. Some of these uncertainties are captured in four predefined study scenarios:[7] a "business-as-usual" case ('Untargeted NEM'), a case where resources are potentially sited at higher value locations on the distribution grid (without assuming any change to the current net metering policy) ('Targeted NEM'), and two bookend cases showing a lower ('Lower NEM Value') and higher value ('Higher NEM Value') of net metered systems due to changes in various assumptions.

Lastly, not only is there uncertainty with regards to the quantified benefits and costs of New York's net metering policy both now and over time, it is important to note that the policy itself may change and evolve, i.e., see the Reforming the Energy Vision (REV) Track 2 White Paper[8] and the recent October 15, 2015 Order issued by the New York Public Service Commission (PSC).[9] It is premature, however, at this point to make assumptions about the outcome of the REV regulatory process with regards to net metering as it is still an ongoing proceeding.

ES.3. Results

As part of this study, we determine that the vast majority of NEM systems installed in New York are distributed solar PV systems. From this perspective we believe that the NEM policy has been successful in encouraging a significant number of New York electric customers to invest in NEM installations, which are expected to grow to at least 500 MW on a *cumulative* statewide basis by the end of 2015.[10]

The results[11] presented in this study are based on a 500 MW penetration level of net metered solar PV systems[12] allocated to specific utilities and customer classes. This assumed allocation is

[7] These scenarios are meant to reflect a range of outcomes that could occur based on sensitivities to the underlying benefit-cost component assumptions, e.g. in the 'Untargeted NEM' and 'Targeted NEM' scenario future energy prices are assumed to conform to the 2015 CARIS I LBMP forecast, with these prices being +/- 10% in the 'Higher NEM Value' vs. 'Lower NEM Value' scenarios. Similarly other value components are varied across the scenarios to create a range of outcomes and potential values to reflect inherent forecast uncertainty.
[8] **http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B48954621-2BE8-40A8-903E-41D2AD268798%7D**
[9] **http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B6D51E352-B4C8-48F9-9354-2B64B14546DC%7D**
[10] As of September 2015 there was approximately 340 MW of net metered generation connected to the six IOU systems in New York with another 1,050 MW proposed to be interconnected. In Long Island we estimate that approximately 155 MW were net metered through the end of September.
[11] For brevity individual utility results are grouped together in this study, with utility by utility specific results presented in the Appendix.

based on NY-Sun's MW Block[13] targets. Since the NY-Sun MW Block program has an overall aggregate goal for the Upstate utilities, the current levels of installations are used to develop utility-specific penetration estimates.[14] The impacts of different penetration levels can be estimated based on these results, e.g. results for a 1,000 MW penetration level can be estimated by doubling the results presented.[15]

In order to answer the Legislature's questions about the cost-effectiveness of NEM systems, three Standard Practice Manual (SPM)[16] benefit-cost 'tests' are evaluated using the DPS BCA White Paper methodology. Specifically, we estimate the benefits and costs of the NEM policy and incentives from the perspective of the non-participating ratepayers (Ratepayer Impact Measure or RIM 'test'); the benefits and costs of the NEM systems from the participating or adopting customer (Participant Cost Test or PCT) and from the perspective of society overall (Societal Cost Test or SCT[17]). The SCT specifically includes the quantification of 'harmful emissions' as defined by the legislation (nitrogen dioxide, sulfur dioxide and carbon dioxide) avoided with NEM systems, i.e., non-financial 'societal' benefits.

In addition to the industry standard SPM cost-effectiveness tests, we present a 'value of solar' analysis by adding both financial and non-financial benefit components of distributed solar PV, and then compare to ratepayer costs to demonstrate an alternative 'value' perspective[18]. This viewpoint is useful to compare the 'value of solar' including non-financial societal benefits such as greenhouse gas (GHG) mitigation and improved air quality to the financial costs borne by

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[12] The study is based on assuming that 500 MW of net metered solar distributed PV is installed in 2015 with an assumed 25-year life. Any sensitivity in the study examining benefits and costs in 2025 also assumes 500 MW of solar PV installed in 2025 with a 25-year life.

[13] NY Sun is the $1 billion program to incent solar PV in New York and the MW Block Program is the specific mechanism for those incentives. For more information see: **http://ny-sun.ny.gov/** and **http://ny-sun.ny.gov/for-installers/megawatt-block-incentive-structure**

[14] This is because the MW Block program only has one Upstate geographic target for all the Upstate utilities. This target then needs to be broken up by each Upstate utility, which is done by allocating this overall target to each utility based on the current levels of solar PV installations in each utility, e.g. if National Grid has X% out of the total solar PV installed in Upstate, then X% of the Upstate MW Block target is allocated to them. ConEd and PSEG Long Island do not have this issue as the MW Block program has distinct targets for those specific utilities/regions.

[15] This linear scalability should hold for the penetration levels associated with the NY Sun and MW Block penetration goals of approximately 3 GW.

[16] **http://www.cpuc.ca.gov/nr/rdonlyres/004abf9d-027c-4be1-9ae1-ce56adf8dadc/0/cpuc_standard_practice_manual.pdf**

[17] For the purpose of this study, the Societal Cost Test is defined to be a Total Resource Cost test (as defined in the SPM) plus select environmental externalities.

[18] This perspective looks at both the direct financial benefits found in the standard RIM test as well as the quantified societal benefits of avoided harmful emissions and to mitigate GHG examined in the SCT. This perspective simply compares the ratepayer expenses of NEM generation including NEM customer bill savings, incentives like the MW Block program, and any associated integration/program costs to this 'full value' of solar.

non-participating ratepayers. The results are presented in ranges that span our four predefined scenarios.

Based on a 500 MW penetration level, the annual net costs[19] to non-participating ratepayers for the NEM policy[20] (as it is currently structured and administered) is $38 million for the Untargeted Case in 2015 and ranges between **$10 million to $60 million in 2015[21] on a statewide basis** (levelized[22] $0.02 to $0.10 per kWh of solar PV production). This translates to potential estimated rate impacts in 2015 for non-participants between **$0.0001 and $0.0004 per kWh**[23] across the four defined scenarios we examine[24] (aggregated across each utility and customer class).

The value of distributed solar PV, i.e., the 'value of solar', based on direct financial benefits ranges from $0.08 to $0.16 per kWh of assumed solar PV production on a levelized basis across the study's four defined scenarios. When adding in the quantified non-financial societal benefits (these range from $0.02 to $0.07 per kWh of solar PV production) then the **'value of solar' ranges from $0.10 to $0.23 per kWh**.

The levelized net benefits to participating ratepayers for installing NEM resources across the four defined scenarios (averaged across each utility and customer class) are between **$0.02 and $0.03 per kWh** of assumed solar PV production for systems installed in 2015.

If NEM customer installations were to be sited or 'targeted' to higher value locations on the distribution grid versus being random or untargeted (i.e., current business-as-usual) then the

[19] When looking at ratepayer impacts and cost-effectiveness, the net benefits to non-participating ratepayers are defined as benefits (utility avoided costs and market price effects) minus costs (NEM customer bill savings/utility lost revenues + NEM program/integration costs + MW Block Incentives). MW Block incentives are assumed to be at current levels in 2015 and zero by 2025. Net costs are defined as the opposite.

[20] In 2015, the net costs to non-participating ratepayers include both the costs of the MW Block Incentive program and NEM. Both factors have an effect on rates. For the Untargeted case, if we exclude the MW Block Incentive from net costs, the net impact to non-participants in 2015 is $16 million and $0.03 per kWh of solar production. Across the 4 scenarios, the net impact to non-participants ranges from a net cost of $36 million to a net benefit of $13 million, or from a net cost of $0.06 per kWh of solar production to a net benefit of $0.02 per kWh of solar production.

[21] This means only costs and benefits accrued in the single snapshot year of 2015.

[22] The benefits and costs of NEM systems are levelized on a real basis assuming a 2% inflation rate over an assumed 25-year life over the entire solar kWh production associated with the assumed 500 MW of NEM installations. The actual effect on rates is much less than these levelized figures.

[23] For reference electric retail rates in New York generally range between $0.10-0.25/kWh across utilities/classes so this rate impact is on the order of ~0.1% to ~0.5% assuming the New York State overall average retail rate is $0.185/kWh.

[24] From the highest NEM value to lowest NEM value scenarios.

net costs of NEM (as it is currently structured and administered) to non-participating ratepayers in 2015 would be **lower by $16 million** ($22 million 'targeted' net costs vs. $38 million 'untargeted' net costs) in 2015 (levelized $0.04 vs. $0.07 per kWh of assumed solar PV production).

The societal perspective shows that NEM systems installed in 2015 result in either net costs or net benefits depending on the scenario. There are ***net costs***[25] over the life[26] of these systems (benefits being 27% to 5% less than the costs) in the 'Lower NEM Value' and 'Untargeted NEM' scenarios. In the 'Targeted NEM' and 'Higher NEM Value' scenarios there is a ***net benefit*** to society that ranges from the benefits being 6% to 27% greater than the costs. Based on forecast trends in NEM installation costs and NEM value over time it is expected that the societal net benefits of NEM installations will increase over time.

Lastly, our analysis of income demographics indicates that those residential customers in New York that have installed NEM systems have higher annual median household incomes on average (approximately $80,000 per year) than the median New Yorker (approximately $60,000 per year) based on census tract data. This difference is primarily driven by the higher incomes of NEM adopter census tracts in Downstate vs. Upstate locations, as well as a large recent uptick in adoptions by customers in Long Island, who generally have higher than statewide average incomes; and the inability of renter households, who may have lower than average incomes, to participate in NEM prior to the introduction of the community distributed generation program in late 2015.

ES.4. Conclusions

A range of reasonable input assumptions and results affect the cost-effectiveness of net metered resources. There are also significant differences in results across utilities, the NEM

[25]When looking at societal impacts and cost-effectiveness, the net benefits to society are defined as benefits (utility avoided costs + federal incentives + societal environmental benefits (SO_2, Nox, and CO_2 impacts)) minus costs (NEM resource costs + program/integration costs). Net costs are defined as the opposite.

[26] Assumed to be 25-years, this is the levelization period.

installation vintage,[27] the customer class, and other key inputs that are captured in the four defined scenarios used in the study. However, several key conclusions can be reached, which are as follows:

Conclusion 1: NEM is a key component of the policy to encourage distributed renewable generation in New York, most especially solar PV. However, while NEM offers a simple and understandable tool for consumers, it is an imprecise instrument with no differentiation in pricing for either higher or lower locational values or higher or lower value technology performance (e.g. peak coincident energy production). The costs and benefits of NEM should be monitored given the fast evolution of this market as contemplated in the recent PSC October 15, 2015 Order.[28]

Conclusion 2: After installing a NEM system, a customer experiences electric bill savings due to reduced consumption, which means the utility is receiving less revenue from that customer including reduced revenues for public purpose programs.[29]

Conclusion 3: The results from cost-effectiveness analysis estimate how much non-participating customers may be paying to enable 500 MW of NEM achievements. Direct financial net costs are borne by non-participating ratepayers across most scenarios and most years of the analysis, especially in the residential customer classes. This analysis shows that potential rate impacts in 2015 for non-participants range between $0.0001 and $0.0004 per kWh across the four defined scenarios (aggregated across each utility and customer class). Unless forecasted NEM adoptions increase much more than expected (i.e., based on the current NY-Sun policy goals), the direct

[27] This refers to the year the NEM systems are installed. It is expected that NEM system costs will decline over time.
[28] **http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B6D51E352-B4C8-48F9-9354-2B64B14546DC%7D**
[29] These public purpose charges range between $0.007 and $0.009 per kWh (or about $4 to $5 per month for the typical New York residential customer) and exist, largely, to reduce the pollution caused by electricity consumption and generation.

These charges are collected on a per kWh basis since these program costs and benefits are caused by kWh consumption and production. NEM customers who now consume less kWh compared to non-NEM customers therefore lower their payment on these charges on a kWh per kWh basis, i.e., every kWh they generate, they avoid paying $0.007 to $0.009 per kWh.

Alternatively every kWh NEM customers generate is one kWh that does not produce the harmful emissions. This prevention of harmful emissions is one of the reasons these programs were created.

financial net costs of the NEM program will remain relatively modest from a statewide perspective, i.e., result in less than an approximately 0.3% annual rate impact in 2015.

Conclusion 4: In some cases the non-financial societal benefits of NEM systems, i.e., GHG mitigation and improved air quality, when added to the financial benefits, may be greater than the direct financial costs of NEM.

Conclusion 5: Depending on the underlying rate design of a NEM customer and their specific consumption pattern, there will be variations around whether an individual customer was underpaying or overpaying its utility cost of service before and after installing a NEM system, which may result in that customer paying less than its cost of service[30].

Conclusion 6: For NEM systems installed in 2015, there is a net cost to society (financial and non-financial benefits are approximately 5% less than costs) over the lifetime of these systems in the baseline scenario. However, with a reasonable assumption of forecasted capital cost declines and increases in benefits it was found that there is a net benefit to society for NEM systems installed in 2025 over the lifetime of these systems (financial and non-financial benefits are approximately 25% higher than costs). If NEM systems can be targeted to higher value locations on the distribution grid, then there is a net benefit to society for both systems installed in 2015 (financial and non-financial benefits higher than costs by 6%) as well as in 2025 (financial and non-financial benefits higher than costs by 43%).

Conclusion 7: Current NEM customers tend to have higher incomes than average statewide customers, although not necessarily higher incomes than households in their immediate geographic regions (e.g. Long Island). Furthermore, NEM customers live in census tracts with slightly more expensive houses, a slightly older population, a younger housing infrastructure, a higher fraction of owner-occupied housing, and in much denser areas than the State's overall average.

[30] Rate design for customers varies significantly by utility and by type of customer class. Generally speaking, residential customer retail rates are designed to recover the utility's cost to serve that class based on average usage and consumption, with over 90% of all variable and fixed costs collected volumetrically on a per kWh basis. However, many customers are not average and by definition any below average or above average customer may not pay the actual cost the utility incurs to serve that specific type of customer. These considerations are inherent and accepted in utility ratemaking.

It is expected that New York’s new community distributed generation program should help address the disproportionate participation of home-owners and single-family homes in the NEM program, which should make solar more accessible to more New Yorkers.

1 Introduction

1.1 Background of Study

On December 17, 2014, Governor Andrew Cuomo signed into law Chapter 510 of the Laws of 2014, which directed New York's Department of Public Service (DPS) to conduct a "net metering study" to perform the following tasks:

+ "Analyze the economic and environmental benefits[31] from and the economic cost burden, if any, of the net energy metering program."
+ "Analyze the extent to which ratepayers receiving service under the net energy metering program are paying the full cost of services provided to them by combined electric and gas corporations and gas corporations, and the extent to which their customers pay a share of costs of public purpose programs through assessments on their electric and/or gas bills."
+ "The study shall also quantify the economic costs and benefits of net energy metering to participants and non-participants and shall further disaggregate the results by utility."
+ "The study shall also gather and present data on the income distribution of residential net metering participants that is publicly available and aggregated by zip code and county."

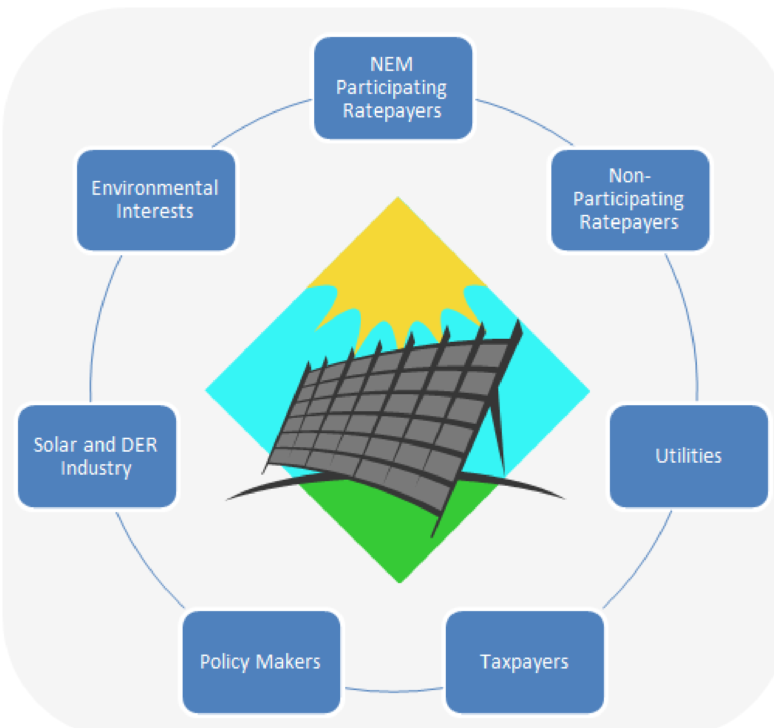
Energy and Environmental Economics, Inc. (E3 or "we") was retained by the New York State Energy Research and Development Authority (NYSERDA) to conduct this study on the behalf of DPS. A project management team consisting of key members of NYSERDA and DPS staff was formed and consulted with regarding the methodology, analysis approach, and results throughout the entire study process.

[31] The legislation specifically states that "As it relates to the environmental benefits, the study shall quantify the approximate avoided level of harmful emissions including, but not limited to, information concerning: nitrogen dioxide, sulfur dioxide and carbon dioxide, as well as other air pollutants deemed necessary and appropriate for study by the commission."

This study looks at a range of possible future outcomes in four defined scenarios[32] to reflect the uncertainty inherent in each of the projected benefit and cost components of net metered resources. This study also looks at the stand alone 'value of solar' perspective from both a direct financial benefits standpoint and a standpoint that includes the non-financial environmental benefits of greenhouse gas (GHG) mitigation and improved air quality.

It is important to note that the net energy metering (NEM[33]) policy is a program designed to encourage distributed energy resources. Further, the NEM issue is a complex one, given its overall success in encouraging distributed energy resources and the wide number of different stakeholders it impacts. There are a number of different stakeholders in the net metering context, some of which may have different and even opposing viewpoints and concerns.

Figure 1: Example of NEM Stakeholders



[32] These scenarios are meant to reflect a range of outcomes that could occur based on sensitivities to the underlying benefit-cost component assumptions, e.g. in the 'Untargeted NEM' and 'Targeted NEM' scenario future energy prices are assumed to conform to the 2015 CARIS I LBMP forecast, with these prices being +/- 10% in the 'Higher NEM Value' vs. 'Lower NEM Value' scenarios. Similarly other value components are varied across the scenarios to create a range of outcomes and potential values to reflect inherent forecast uncertainty.

[33] When we refer to 'NEM' throughout this study such as "NEM installations" or "NEM generation" we mean net metered solar PV installations or generation unless otherwise explicitly stated.

1.2 General Study Approach

Study Goals Chapter 510
- Define framework to answer the questions in Chapter 510, using an industry standard approach consistent with the DPS BCA White Paper and other national studies, to evaluate New York's existing NEM policy.
- Consult with Project Management Team throughout the study process.

Benefit-Cost Analysis
- Complete benefit cost analysis of the NEM policy key perspectives: participating ratepayers, non-participating ratepayers, and society.

Other Analyses
- Complete an analysis of the household income distribution of residential net metering customers using census tract data and compare to New York median household income overall.
- Examine the 'value of solar' (both financial and non-financial societal benefits).

Results
- Summarize the overall results for existing NEM customers, and highlight differences across key dimensions including time. Use specific differences between customer classes, utilities, and scenarios to highlight key insights.

Conclusions
- Draw several high-level generall conclusions regarding the study results and answer key questions enumerated by the legislation.

1.3 Analysis Overview

The table below summarizes the analysis approach used in this study highlighting the key dimensions and major assumptions analyzed.

Figure 2: Dimensions of Analysis

Dimension	Overview
Location	+ Each of the seven (7) New York utilities[34] (6 investor owned utilities and PSEG Long Island)
Timeframe	+ Specific years of 2015 vs. 2025 + Lifetime of NEM installations (25-years)
Customer Type	+ Residential + Small Non-Residential + Large Non-Residential
Scenarios	+ Lower NEM Value + Untargeted NEM + Targeted NEM + Higher NEM Value
Adoption Levels	+ Estimated 2015 solar PV installations + All other NEM technologies and analyses reported on a per kWh of assumed NEM generation basis
NEM Generation	+ All generation or total production + Export-only (generation not consumed on-site)
Perspective	+ 'Value of Solar' examination
Income Analysis	+ Income demographic analysis of residential customers
Standard Practice Cost Tests	+ Participant Cost Test (PCT) + Ratepayer Impact Measure (RIM) + Societal Cost Test (SCT)

1.4 NEM in New York

[34] These are the six investor owned utilities in New York: Consolidated Edison Company of New York (ConEd), National Grid (NiMo), New York State Electric and Gas (NYSEG), Rochester Gas and Electric (RG&E), Orange and Rockland Utilities (ORU), and Central Hudson Gas and Electric (CHG&E or Central Hudson) plus PSEG Long Island (LIPA).

1.4.1 WHAT IS NEM?

In a conventional NEM situation in New York a customer-sited renewable energy system is connected to the utility grid through a customer's utility meter. This is known as "behind-the-meter (BTM) generation." At any given moment, if the site is using more electricity than the BTM system is producing, all the electricity produced by the system is used on-site and the site's electricity needs are supplemented from the grid. If the site is using less electricity than the system is producing, the excess electricity is exported to the grid and the customer receives a credit[35].

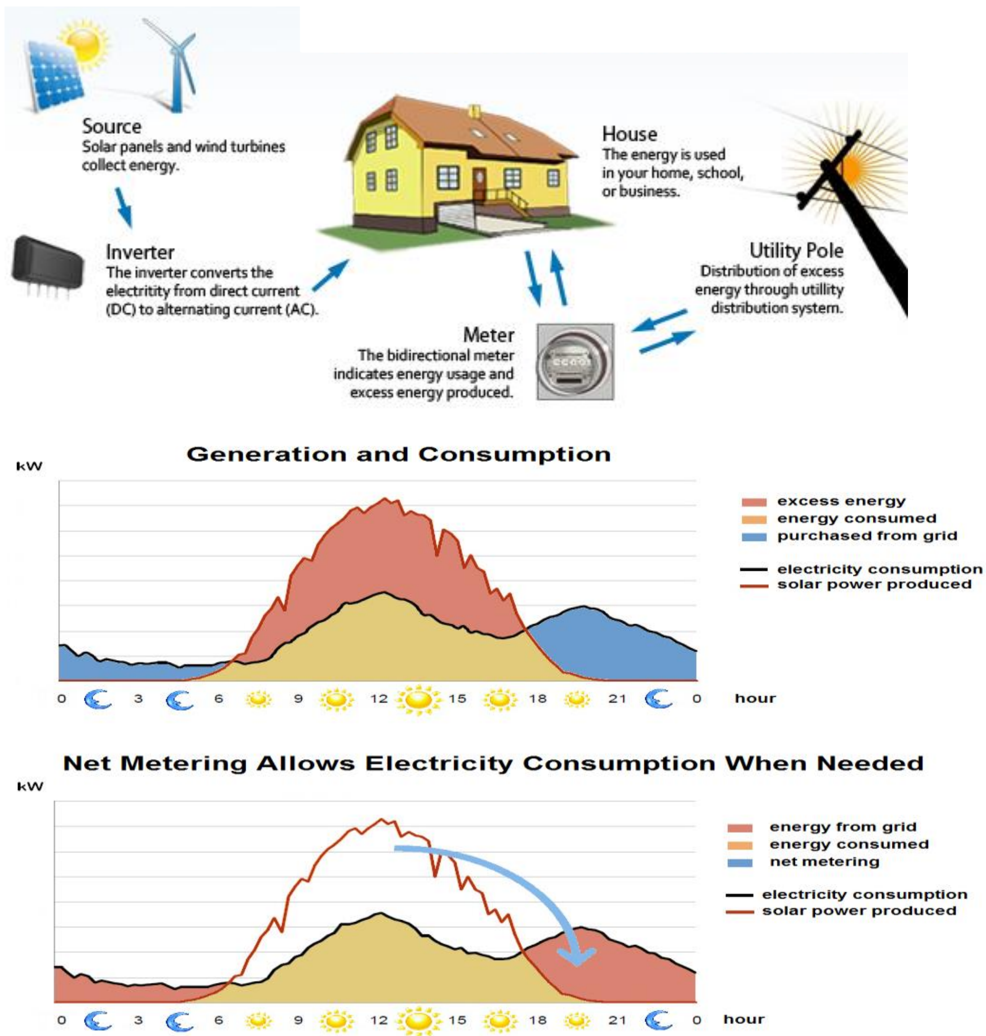
1.4.2 EVOLUTION OF NEM

NEM is working to encourage 'market transformation' in New York and grow distributed renewable generation like solar, but it is an imprecise tool tied to the retail rate that does not compensate for actual value delivered to the electric grid and/or society, which can vary by location and/or type of NEM technology performance.

1.4.3 HOW NEM WORKS

[35] This credit is generally based on the volumetric or "variable" electric retail rate of the customer, i.e., it does not include any charges that are fixed and do not vary with per kilowatt-hour (kWh) usage. This credit is typically recorded as negative use and is commonly referred to as "spinning the meter backwards." At the end of the billing cycle, the grid-supplied electricity and the credits for any exported electricity are reconciled, and any surplus credits can be carried forward to the next billing cycle. For commercial and industrial accounts in New York, overages are monetized to allow application against non-volumetric charges and then carried forward indefinitely on a kWh basis. Residential and small commercial accounts are maintained as kWh credits and annually, "cashed out" at a utility's existing "avoided cost" rates for residential accounts. The specifics of net energy metering are dependent on the customer's service classification as well as each utility's specific tariff.

Figure 3: How Net Metering Works[36]



1.4.4 NEM ELIGIBLE TECHNOLOGIES

A number of technologies are eligible for NEM although distributed solar PV makes up the majority of current NEM installations based on historical installation data provided by NYSERDA and DPS.

[36] http://upload.wikimedia.org/wikipedia/commons/3/33/Daily_net_metering.png; http://www.michigan.gov/images/mpsc/netmetering_370651_7.jpg

It is important to note that there has been a large increase in NEM eligible installations and for certain utilities the historical net metering limits may be reached shortly. In fact for certain utilities the amount of NEM eligible installations in the interconnection queue, i.e., pipeline, exceeds the historical NEM limits or caps. The New York Public Service Commission (PSC) issued an Order on October 15, 2015[37] suspending the historical NEM caps on an interim basis until a valuation for distributed energy resources is complete as part of the Reforming the Energy (REV) Proceeding[38].

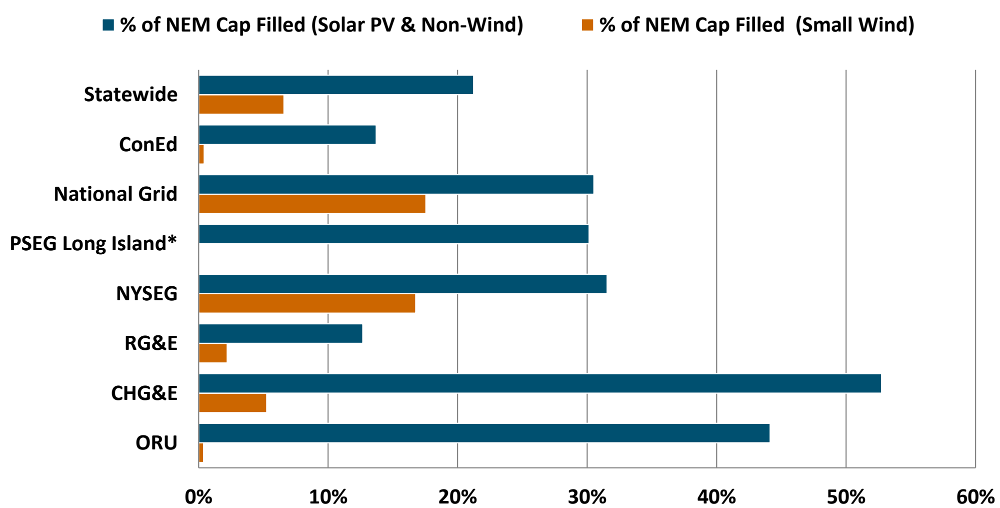
[37] http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B6D51E352-B4C8-48F9-9354-2B64B14546DC%7D
[38] http://www3.dps.ny.gov/W/PSCWeb.nsf/All/CC4F2EFA3A23551585257DEA007DCFE2?OpenDocument

Figure 4: Technologies Eligible for NEM in New York[39]

	Overview
Eligible Renewable/Other Technologies:	Solar Photovoltaics, Wind (All), Biomass, Combined Heat & Power, Fuel Cells using Non-Renewable Fuels, Wind (Small), Hydroelectric (Small), Anaerobic Digestion, Fuel Cells using Renewable Fuels, Microturbines
Applicable Sectors:	Commercial, Industrial, Local Government, Nonprofit, Residential, Schools, State Government, Federal Government, Agricultural, Institutional
NEM System Capacity Limit:	+ Solar: 25 kW for residential; 100 kW for farms; 2 MW for non-residential + Wind: 25 kW for residential; 500 kW for farm-based; 2 MW for non-residential + Micro-hydroelectric: 25 kW for residential; 2 MW for non-residential + Fuel Cells: 10 kW for residential; 1.5 MW for non-residential + Biogas: 1 MW (farm-based only) + Micro-Combined Heat and Power (CHP): 10 kW (residential only)
Aggregate NEM Capacity Limit: (Limits are Currently Floating)	6% of utility's 2005 demand for solar, farm-based biogas, fuel cells, micro-hydroelectric, and residential micro-CHP 0.3% of utility's 2005 demand for wind
Net Excess Generation:	Generally credited to customer's next bill at retail rate (except avoided-cost rate for micro-CHP and fuel cells); excess for residential PV and wind and farm-based biogas is reconciled annually at avoided-cost rate; excess for micro-hydro, non-residential wind and solar, and residential micro-CHP and fuel cells carries over indefinitely
Ownership of Renewable Energy Credits:	Not addressed
Meter Aggregation or Remote Net Metering:	Allowed for non-residential and farm-based customers with solar, wind, farm-based biogas, and micro-hydroelectric systems

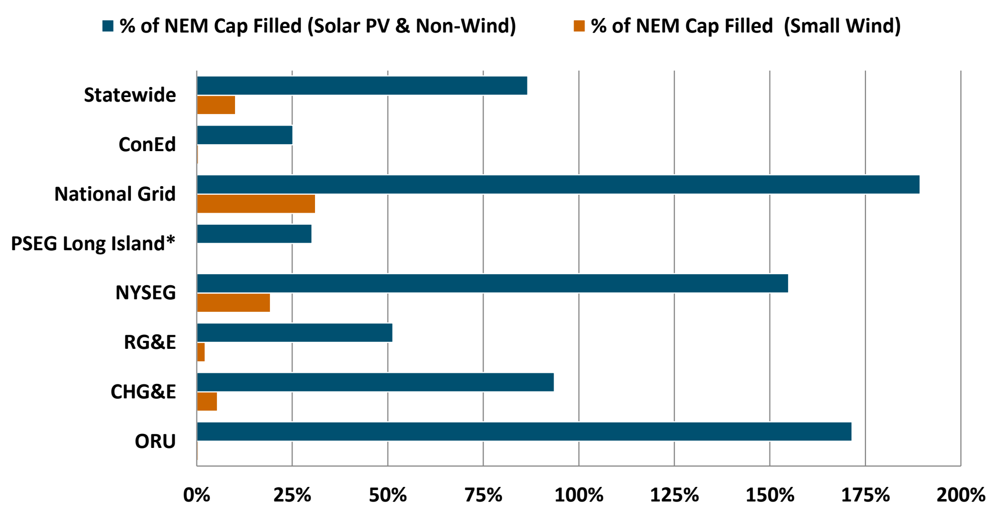
[39] http://programs.dsireusa.org/system/program/detail/453

Figure 5: Historical NEM Caps by Utility vs. Currently Installed Capacity of NEM Systems as of September 2015



*The solar PV & non-wind NEM cap for PSEG Long Island is 3% of 2005 utility peak demand vs. 6% for the other NY utilities. The small wind NEM cap is 0.3% of 2005 peak demand for all utilities. Note, there is no reported data on the amount of net metered small wind for PSEG Long Island.

Figure 6: Historical NEM Caps by Utility vs. Currently Installed and Pipeline Capacity of NEM Systems as of September 2015



*The solar PV & non-wind NEM cap for PSEG Long Island is 3% of 2005 utility peak demand vs. 6% for the other NY utilities. The small wind NEM cap is 0.3% of 2005 peak demand for all utilities. Note, there is no reported data on the amount of net metered small wind for PSEG Long Island.

1.5 Context for NEM and Supporting Programs

1.5.1 NY-SUN PROGRAM

Governor Andrew Cuomo launched the New York Sun (NY-Sun) Initiative during his 2012 State of the State Address. In 2014, Governor Cuomo announced $1 billion in investment in the NY-Sun initiative, concomitant with a goal of adding more than 3,000 megawatts (MW) of solar capacity in the State by 2023. This initiative consolidates efforts at NYSERDA, Long Island Power Authority (LIPA) (now operated by PSEG Long Island), and the New York Power Authority (NYPA) under a single incentive structure with Megawatt Block targets (see below). The ultimate goal of the program is to "spur development of a market-driven, sustainable, subsidy-free solar industry."[40]

1.5.1.1 MW Block Incentive Program

The MW Block Incentive program is the means for disbursing the aforementioned ~$1 billion incentive budget to qualifying solar electric generation built in New York from 2014-2023. The MW Block system allocates targets to three areas – Long Island, Con Edison territory, and Upstate – with three sectors comprising each regional block. The sectors are:

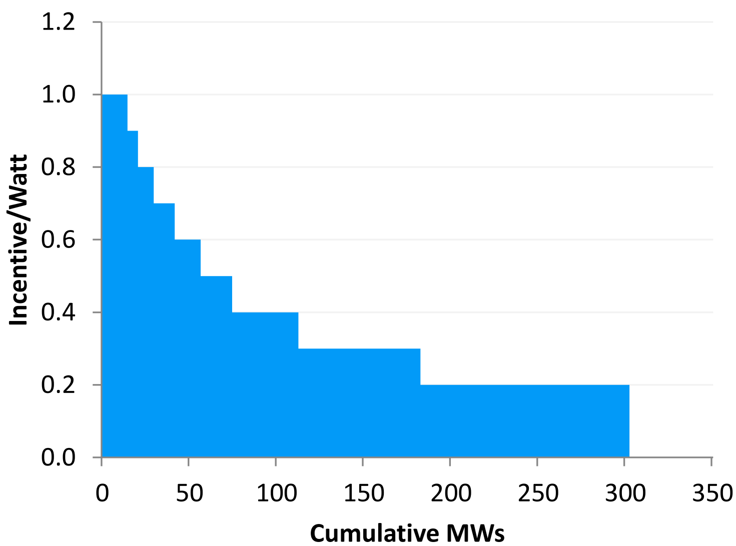
1) Residential systems up to 25 kilowatts (kW);
2) Small non-residential systems up to 200 kW; and
3) Large non-residential systems larger than 200 kW and up to 2 MW.

The <200 kW residential and small non-residential blocks opened in August 2014 with retroactive funding for projects installed beginning January 1, 2014, while the >200 kW to 2 MW large non-residential block opened on May 4, 2015. The general structure of the block incentives is to have declining incentive levels for each tranche of solar PV contracts. For example, the ConEd residential incentive starts at $1.00/Watt-DC for the first 14 MW contracted and

[40] See NY-Sun Initiative Fact Sheet. Available online at **http://ny-sun.ny.gov/About/About-NY-Sun.aspx**

installed, then steps down to a $0.90/Watt incentive for the following 6 MW, and so on[41]. Incentives for other regions and system sizes are designed similarly.

Figure 7: ConEd Residential Block Structure



Regional targets differ for both reasons of region size and maturity of the solar market in that region. For all targets the goal is to drive down costs, particularly balance-of-system (or "soft") costs so that solar is competitive on its own economic merits even as the size of the incentive steps down with increasing deployment.

1.5.2 NEW YORK STATE ENERGY PLAN

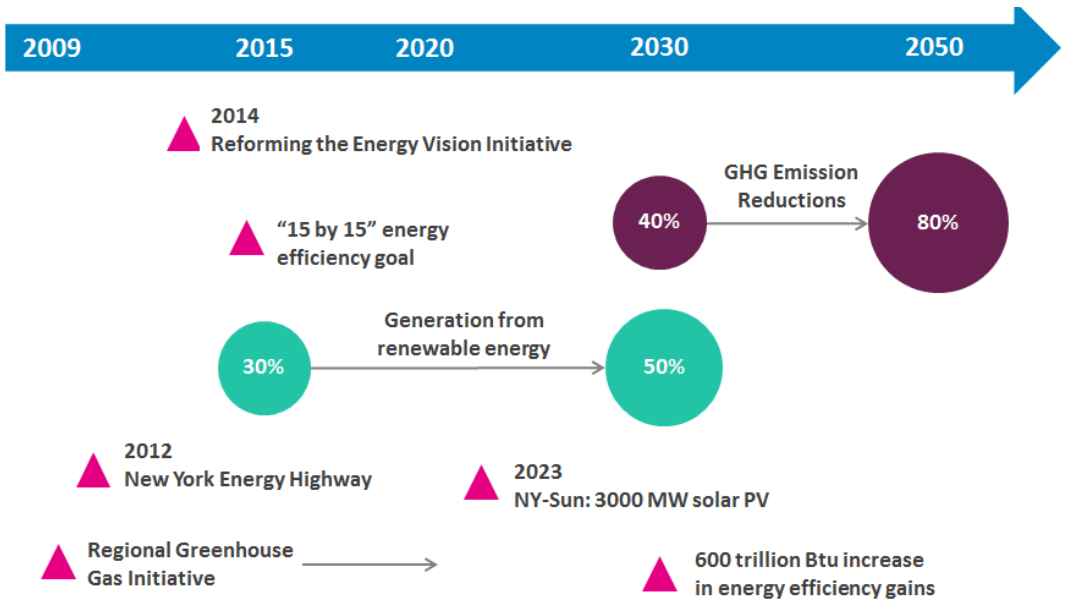
In 2009, the New York State Energy Planning Board (NYSEPB) was established to launch an energy planning process and develop a State Energy Plan.[42] The *2015 New York State Energy Plan*, released by NYSEPB in June 2015[43], coordinates a number of programs and initiatives administered by New York's energy-related agencies and authorities, including Governor Andrew Cuomo's REV Initiative. Three clean energy targets for 2030 are outlined: (1) 40 percent reduction in GHG emissions from 1990 levels; (2) 50 percent electricity generation from

[41] See http://ny-sun.ny.gov/For-Installers/Megawatt-Block-Incentive-Structure for more information on the MW Block incentives.
[42] http://energyplan.ny.gov/
[43] http://energyplan.ny.gov/Plans/2015

renewables; and (3) 600 trillion Btu increase in energy efficiency. These are interim targets along the state's ultimate pathway to 80% GHG emission reductions by 2050.

The range of regulatory reforms and initiatives currently underway in the market is illustrated the figure below.

Figure 8: New York Market and Regulatory Reform Timeline



1.5.2.1 Reforming the Energy Vision (REV)

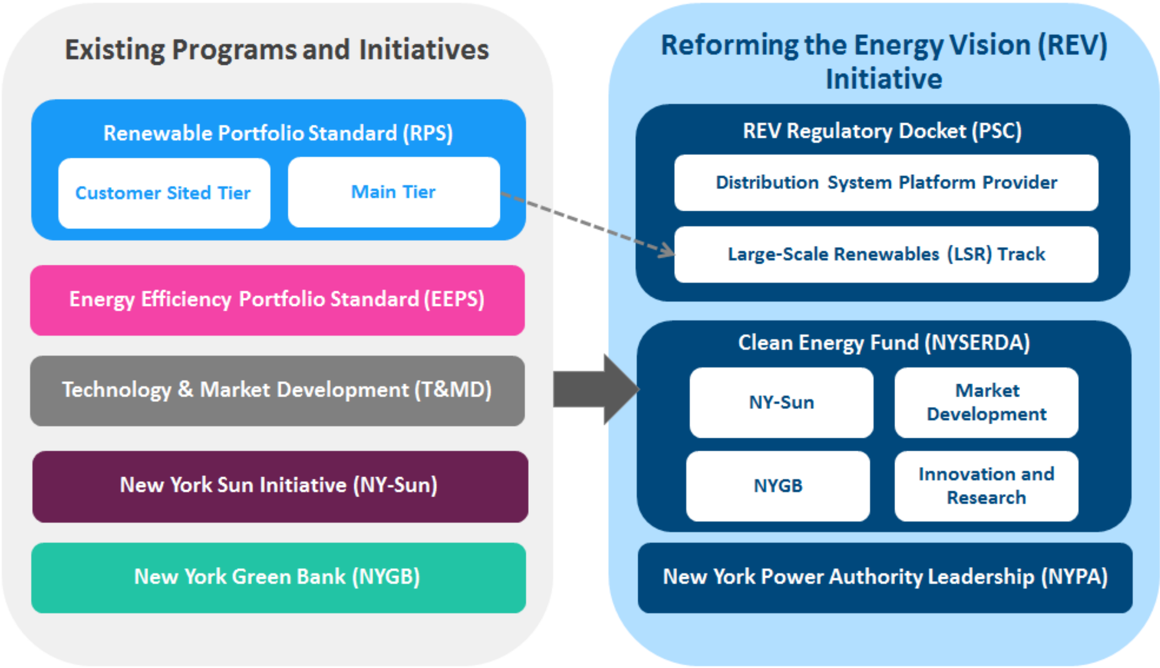
New York's Reforming the Energy Vision (REV) Initiative[44] is the state's comprehensive energy policy to meet its policy objectives of sustainability, reliability and affordability. The REV Initiative includes a transition of existing clean energy programs and regulatory reforms, many of which are underway and still being formed. The 2015 New York State Energy Plan, released in June 2015, coordinates the REV Initiative among state agencies and outlines three strategic pillars:

[44] http://www3.dps.ny.gov/W/PSCWeb.nsf/All/CC4F2EFA3A23551585257DEA007DCFE2?OpenDocument

+ PSC's REV Regulatory Docket, which includes regulatory reforms to provide customers greater choice and value, expand the use of distributed energy resources (DER) and redesign the investor-owned utility business model;
+ NYSERDA's Clean Energy Fund (CEF), which will serve as the funding vehicle for NYSERDA's ongoing and future clean energy investment programs; and
+ NYPA, in their role as a state power authority, will "lead by example" through public investment in energy efficiency and renewable energy

As shown in the figure below, the REV Initiative organizes a number of disparate programs and initiatives into the pillars outlined above. The CEF replaces the programs supported by the system benefits charge (SBC), including the energy efficiency (EE) and renewable portfolio standards (RPS) programs, and continues the existing NY-Sun and New York Green Bank initiatives.

Figure 9: REV Initiative Transition



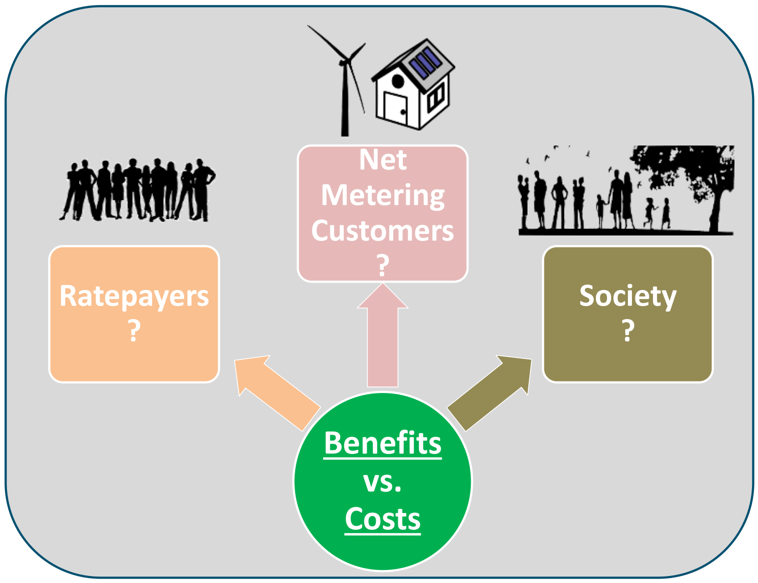
2 Methodology

2.1 Analysis

The following section describes the specific analytical methodology used in this study, which primarily consists of using a Benefit-Cost Analysis (BCA). One key aspect of any kind of BCA should be evaluating cost-effectiveness from multiple perspectives. This is consistent with DPS BCA White Paper[45]. In addition a BCA should be transparent about its assumptions as well as be clear on the benefits and costs being evaluated as well as those not being evaluated, which again is consistent with the DPS BCA White Paper. A BCA should evaluate lifecycle economics, but can also report impacts for specific years. In addition a BCA should also consider uncertainty given long term projections under lifecycle economics. For example, a key benefit of NEM installations are avoided utility energy purchases or costs over the lifetime of these installations, which has a great deal of associated forecast uncertainty. Lastly, a BCA should look at both participating customer incentives such as MW Block Incentives and bill savings when looking at total non-participating ratepayer impacts or costs.

[45] http://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/26be8a93967e604785257cc40066b91a/$FILE/Staff_BCA_Whitepaper_Final.pdf

Figure 10: Multiple Perspectives Should be Examined when Constructing a Benefit-Cost Analysis



2.1.1 LITERATURE REVIEW

We believe that this study is in line with how other jurisdictions have examined the costs and benefits of NEM and distributed solar PV (both from a direct financial and non-financial standpoint) although the results of various studies do exhibit a wide range of potential values depending on the purpose of the study and its analytical rigor. In addition, results vary by location and can be significantly different depending on state policies. Therefore, a result based on the unique aspects of a specific jurisdiction does <u>not</u> usually translate to another jurisdiction.

Further, not all jurisdictions have examined cost-effectiveness of distributed solar PV and/or NEM systems using industry standard practices. Furthermore, only a subset of studies examines <u>both</u> the costs and benefits, as most studies are primarily focused on examining the benefits (financial and non-financial), i.e., the 'value of solar'.

There are industry standard methodologies that have been used in multiple jurisdictions for a number of years when examining the benefits and costs of distributed energy resource programs and technologies as well as methodologies that have been tailored specifically for distributed energy resources in New York, which are as follows:

+ Standard Practice Manual[46]

+ DPS BCA White Paper[47]

+ NREL's 'Methods for Analyzing the Benefits and Costs of Distributed Photovoltaic Generation to the U.S. Electric Utility System"[48]

+ EPRI's 'Economic Costs and Benefits of Distributed Energy Resources'[49]

Figure 11: Value of Solar and NEM Benefit-Cost Studies Vary Widely in Terms of Methodology

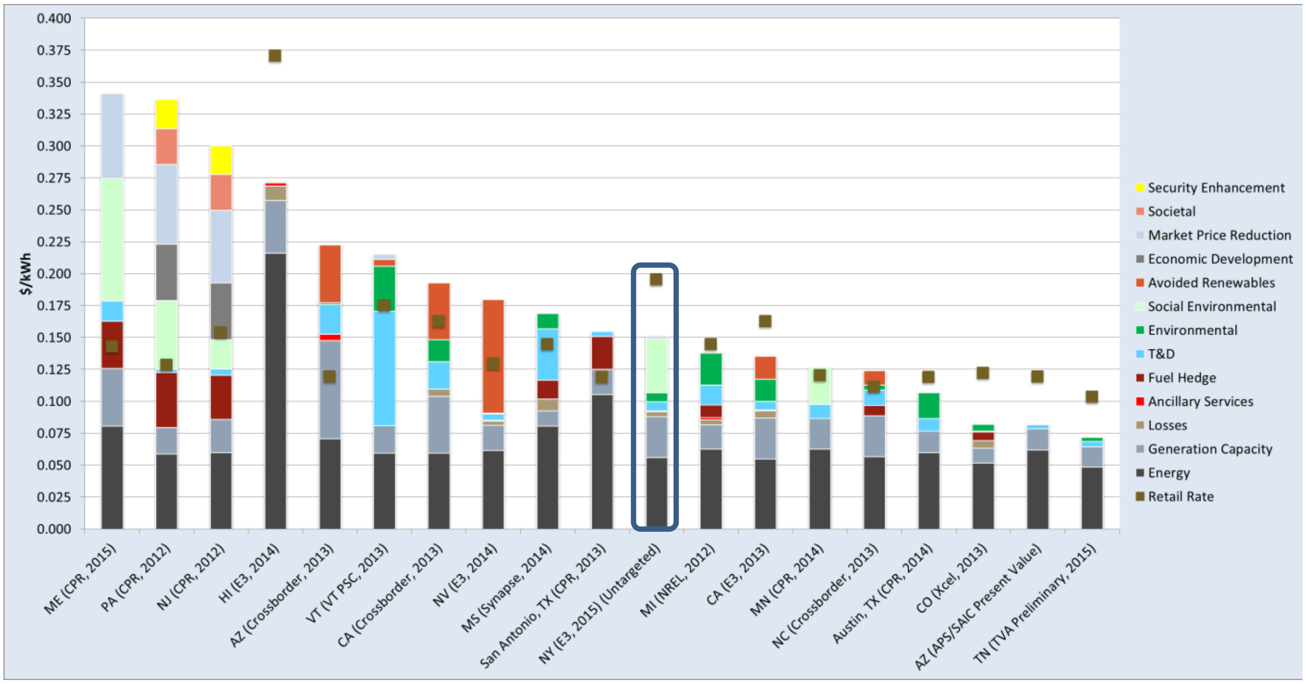
EXAMPLES OF RECENT NEM VALUE STUDIES FROM STATES, UTILITIES, CONSULTANCIES, AND STAKEHOLDERS

Included	●
Included as a sensitivity	◉
Represented/captured in other values	○

STATE	STUDY	BENEFITS ANALYZED												COSTS ANALYZED				BENEFIT/COST TESTS							
		Avoided Energy (incl. O&M, fuel costs)	Avoided Fuel Hedge	Avoided Capacity (generation and reserve)	Avoided Losses	Avoided or Deferred T&D Investment	Avoided Ancillary Services	Market Price Reduction	Avoided Renewables Procurement	Monetized Environmental	Social Environmental	Security Enhancement/Risk	Societal (incl. economic/jobs)	PV Integration	Program Administration	Bill Savings (Utility Revenue Loss)	Utility/DER Incentives	Total Resource Cost Test (TRC)	Program Administrator/Utility Cost Test (PACT/UCT)	Cost of Service (COS) Analysis	Ratepayer Impact Measure (RIM)	Participant Cost Test (PCT)	Societal Cost Test (SCT)	Revenue Requirement Savings: Cost Ratio	Net Cost Comparison of NEM, FIT, Other
ARIZONA	Crossborder Energy (2013)	●		●	●	●	●	○	●	●		○	○	●		●	◉				●				
ARIZONA	APS/SAIC (2013)	●		●	○	●																			
CALIFORNIA	E3 (2013)	●		●	●	●	●		●	●				●	●	●				●	●				
CALIFORNIA	Crossborder Energy (2013)	●		●	●	●	●		●	●				●	●	●					●				
COLORADO	Xcel (2013)	●	●	●	●	●	○			●				●											
HAWAII	E3 (2014)	●		●	●	◉	●				◉														●
MAINE	Clean Power Research (2015)	●	●	●	○	●	○	●			●			●											
MASSACHUSETTS	La Capra Associates (2013)	●		●	○	●		●	●	●		◉	◉			●	●	●			●				
MICHIGAN	NREL (2012)	●	●	●	●	●	●		○	●															
MINNESOTA	Clean Power Research (2014)	●	○	●	●	●					●														
MISSISSIPPI	Synapse Energy Economics (2014)	●	●	●	●	●				●				●	●	●		●				●		●	
NORTH CAROLINA	Crossborder Energy (2013)	●	●	●	○	●	○	○	●	●	◉	○	○	●		●	●								
NEW JERSEY	Clean Power Research (2012)	●	●	●	●	●		●	○		●	●	●	●											
NEW YORK	E3 (2015) (Based on DPS BCA)	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●		●	●	●	●		
NEVADA	E3 (2014)	●		●	●	●	●		●	●				●	●	●	●	●	●		●	●	●		
PENNSYLVANIA	Clean Power Research (2012)	●	●	●	●	●		●	○		●	●	●	●											
TENNESSEE	TVA (2015)	●		●	○	●				●	◉														
TEXAS (AUSTIN)	Clean Power Research (2014)	●	○	●	●	●			○	●															
TEXAS (SAN ANTONIO)	Clean Power Research (2013)	●	○	●	●	●				●															
VERMONT	Vermont PSC (2013)	●		●	○	●	●	●	●	●	◉				●	●					●				

[46] http://www.cpuc.ca.gov/nr/rdonlyres/004abf9d-027c-4be1-9ae1-ce56adf8dadc/0/cpuc_standard_practice_manual.pdf
[47] http://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/26be8a93967e604785257cc40066b91a/$FILE/Staff_BCA_Whitepaper_Final.pdf
[48] http://www.nrel.gov/docs/fy14osti/62447.pdf
[49] http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000000001011305

Figure 12: Value of Solar and NEM Benefit-Cost Studies Vary Widely in Terms of Results based on Methodology, Jurisdiction, and Study Sponsors*



*Note, this chart is not meant to represent a benefit-cost test, but merely serves as a comparison of how the various potential benefits both direct (energy, generation capacity, losses, ancillary services, fuel hedge, T&D, environmental, avoided renewables, and market price effect) and non-financial (social environmental, societal, economic development, security enhancement, and other) have been calculated in each study which is then compared against the average state residential retail rate as reported by the U.S. Energy Information Administration (EIA). This average rate is an aggregate number that includes both fixed and variable charges.

As can be seen there are many types of benefits examined across the studies surveyed, some reflect direct cost avoidance, while many others reflect the monetization of non-pecuniary societal benefits. It is important to note that these benefits are not consistent in methodologies, perspectives, or analytical rigor across studies. To that end we categorized various benefits into a smaller number of subcategories for ease of comparison across studies. For example, the 'Social Environmental' category can include non-financial health impacts from SO_2 and NO_x along with Social Carbon Costs depending on the study. The 'Environmental' categories can include financial CO_2 impacts along with other potential benefits. Given these caveats we believe that this comparison serves as useful context for this study and the results presented, but each study's results are unique and may or may not be useful as a direct comparison.

2.1.2 COST EFFECTIVENESS PERSPECTIVES

This analysis evaluates the benefits and costs of the NEM systems from three perspectives originally established in the Standard Practice Manual (SPM), and later adapted for use in the New York context. The most recent adaptation can be found in the DPS July 1, 2015 BCA White Paper. These perspective based analyses have been used for decades in a number of jurisdictions to determine the cost-effectiveness of a variety of consumer distributed energy resource programs. Each perspective is defined by a 'cost test' and collectively they define a broad assessment of cost-effectiveness. These industry standard tests provide a holistic analytical and methodological structure to examine the benefits and costs of energy resources from a variety of perspectives. There is not a single correct cost test to use in general, each 'test' aims to answer a different question as follows:

+ The *Participant Cost Test (PCT)* analyzes the financial proposition of purchasing and installing a NEM system from a participant's perspective. If a customer's bill savings including NEM compensation are greater than the customer's post-incentive capital costs paid, then the customer experiences a monetary financial gain from installing a NEM system.
    - Note, this test is highly dependent on a number of variables like each individual customer's specific electric retail rate schedule, the NEM system financing mechanism, tax status, location, etc.
+ The *Ratepayer Impact Measure* (RIM) measures the impact of NEM generation on non-participating utility customers. The RIM test compares the utility avoided costs from not having to provide the energy generated by the NEM system (reduction in revenue requirement) to the incremental utility system costs such as program administration and the lost utility revenue due to reductions in NEM adopter customer bills. If there is a net shortfall, over time the utility would be allowed to increase customer rates to make up for the shortfall, which results in non-participants bearing those costs. In New York, where the utilities have revenue decoupling mechanisms (RDM),[50] this assumption is reasonable as utility revenues are normally reconciled or 'trued up' on an annual basis.

[50] http://www3.dps.ny.gov/W/PSCWeb.nsf/All/A0227F4885E1769485257687006F38C2?OpenDocument

+ The *Societal Cost Test (SCT[51])* captures the total impact of NEM on the state of New York including non-financial societal benefits or externalities that are not currently paid for by ratepayers. The test includes the net impacts of participants, non-participants, and utility/program administrators. Net costs between parties within New York and benefits that are not directly financial are excluded from this analysis.

Some of these standard cost test components, such as customer bill "savings," are transfers from participants to non-participants. This occurs because lower bills for participants reduce the revenue the utility collects, and to the extent these bill reductions are greater than any utility cost-savings, the next utility rate case or decoupling adjustment would increase rates to make up the shortfall, increasing bills of non-participants. Note that these transfers may be treated as a cost in some tests and a benefit in others due to differences in the cost test perspectives.

Figure 13: Benefit and Cost Components of the Standard 'Cost Tests'

	Benefits	Costs
Participant Cost Test (PCT)	Customer Bill Reductions + State Incentives[52] + State Tax Credits/Incentives + Federal Tax Credits	NEM System Costs
Ratepayer Impact Measure (RIM)	Utility Avoided Costs + Market Price Effects	Customer Bill Reductions + State Incentives + Utility Integration Costs + Utility Administration Costs
Societal Cost Test (SCT)*	Utility Avoided Costs + Federal Tax Credits + Societal Benefits + Health Benefits	NEM Generation System Costs + Utility Integration Costs + Utility Administration Costs

*Based on the DPS BCA interpretation of the Standard Practice Manual's SCT, the Market Price Effect was not included as a benefit in the SCT as in New York this is viewed as a transfer payment from producers to consumers with no net "societal" benefit[53]. It is however included in the RIM test.

[51] For the purpose of this study, the Societal Cost Test is defined to be a Total Resource Cost test (as defined in the SPM) plus select environmental externalities.
[52] This consists of the MW Block Incentive program for distributed solar PV. Both the PCT and RIM tests assume that the MW Block Incentive program is funded entirely by ratepayers in the year that the incentives are disbursed.
[53] See footnote on p.66 of "The Renewable Portfolio Standard: Mid Course Report" that was filed by Staff on October 26, 2009 in Case 03-E-0188. See: http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=230CE88F-60A5-475B-A24A-6FC9B2780DEF.

Future benefits and costs are discounted to their installation date and reported in 2015 dollars. The PCT, RIM, and SCT[54] cost-tests all use the a 5.5% real discount rate as representative of a generic utility's weighted average cost of capital (WACC) and a 2% inflation forecast to determine the nominal discount rate for any net present value (NPV) calculation.

For any calculations of levelized costs, i.e., on a $ per kWh basis, a real economic or constant real approach is used rather than a nominal levelization. The total NPV is the same under either approach. The constant real levelized cost-effectiveness provides a better comparison of the cost-effectiveness over time since the results are comparable between different vintages of installations.

Figure 14: Cost Test Result Interpretations

	Benefits GREATER than Costs	Benefits LESS than Costs
Participant Cost Test (PCT)	Net metered customers save money by installing NEM systems	Net metered customers spend more on electricity after installing NEM systems
Ratepayer Impact Measure (RIM)	Average utility rates decrease, decreasing bills of non-participants	Average utility rates increase, increasing bills of non-participants
Societal Cost Test (SCT)	There is a net benefit to the state of New York when accounting for health/social externalities	There is an net cost to the state of New York even accounting for health/social externalities

2.1.3 VALUE OF SOLAR ANALYSIS

In addition to the three standard cost tests enumerated above we examine a 'value of solar' perspective. We look at both the direct financial benefits in the standard RIM test as well as

[54] Note, the societal components of SO_2 and NOx health impacts and the Social Cost of Carbon are based on EPA forecasts that assume different damage values at different discount rates. While these values are calculated with different discount rates that result in different values, the analysis takes these discounted values and then applies a constant 5.5% discount rate. For example, the EPA uses a 3.0% discount rate to determine one value of the Social Cost of Carbon. The analysis then takes this discounted value and applies the 5.5% discount rate assumed. Different scenarios have different values assumed for these EPA forecasts.

non-financial societal benefits examined in the SCT[55] in order to construct a total 'value' metric for NEM systems. This is one perspective in comparing non-participating ratepayer expenses, which consist of compensation paid to NEM customers (i.e., bill savings) plus any NEM incentives (i.e., MW Block incentives) and integration/program costs to this total 'value'.

2.1.4 COSTS AND BENEFITS EVALUATED

There are two primary types of benefits associated with NEM systems that are examined in this study:

1. Direct financial benefits such as utility avoided energy costs; and,
2. Non-financial societal benefits such as GHG mitigation and improved air quality.

In this study we examine a number of benefits and costs in an explicit and quantitative fashion. There are, however, several other potential benefits that are qualitatively discussed in line with guidance from the DPS BCA White Paper. The figure below describes the specific benefits and costs examined in each BCA perspective.

[55] There is a clear distinction between indirect benefits that accrue to society vs. ratepayers. In this study we are equating indirect benefits that accrue to society as being equally applicable to non-participating ratepayers. There is uncertainty if this assumption is appropriate especially with regards to the Social Cost of Carbon which is a worldwide pollutant with worldwide costs. The Social Cost of Carbon may understate or overstate the cost to both New York state and its ratepayers. This uncertainty is reflected in part in the various sensitivities assigned to this value component across the four defined scenarios in this study.

Figure 15: The Benefits, Costs, and Perspectives Examined in this BCA

Benefit-Cost Components	Participant Cost Test	Ratepayer Impact Measure	Societal Cost Test
Energy (LBMP) (No Carbon)	------	✓ (Benefit)	✓ (Benefit)
T&D Losses	------	✓ (Benefit)	✓ (Benefit)
Monetized Carbon Costs	------	✓ (Benefit)	✓ (Benefit)
Ancillary Services	------	✓ (Benefit)	✓ (Benefit)
Reactive Power	------	Quantifiable, but value assumed to be low based on new inverter technologies and current utility costs	
System Capacity (ICAP)	------	✓ (Benefit)	✓ (Benefit)
Transmission Capacity	------	Assumed to be reflected in the ICAP and LBMP Values	
Sub-Transmission Capacity	------	✓ (Benefit)	✓ (Benefit)
Distribution Capacity	------	✓ (Benefit)	✓ (Benefit)
Market Price Effect	------	✓ (Benefit)	------
Resiliency/Restoration	------	Assumed to be reflected in utility distribution costs; difficult to calculate as these values differ greatly between customers/locations	
Social Cost of Carbon	------	------	✓ (Benefit)
Health Benefits (SO_2 and Nox)	------	------	✓ (Benefit)
Customer Bill Savings	✓ (Benefit)	✓ (Cost)	------
Integration Costs	------	✓ (Cost)	✓ (Cost)
Program Costs	------	✓ (Cost)	✓ (Cost)
Tax Incentives (Federal)	✓ (Benefit)	------	✓ (Benefit)
Tax Incentives (State)	✓ (Benefit)	------	------
Direct Incentives (State)	✓ (Benefit)	✓ (Cost)	------
NEM Capital Costs	✓ (Cost)	------	✓ (Cost)

2.1.4.1 Direct Financial Benefits and Costs Currently Affecting New York and New York Ratepayers

We examine each NEM system over a 25-year assumed life. In order to perform this lifecycle analysis each benefit and cost component must be forecast over that lifetime. It is important to note that each benefit and cost component has an associated forecast uncertainty associated with it, especially given each NEM system's long lifetime. A summary description of each benefit and cost component is provided in the table below, with more details provided in the study's Appendix.

Figure 16: Detailed Description of the NEM Financial Benefit-Cost Components

Cost Test Criteria	Component	General Description	Initial Study Calculation Methodology/Proxy Value
Utility Avoided Costs	Energy	Reduction of costs due to reduction in production from the marginal conventional wholesale generating resource associated with the adoption of distributed NEM.	The value of energy for each utility is derived from a forecast based on production simulation modeling per the NYISO's Congestion Assessment and Resource Integration Study (CARIS). This includes generation energy losses and compliance costs for criteria pollutants but does not include any financial CO_2 emission costs.
	Energy Losses	Reduction of electricity losses from the points of generation to the points of delivery associated with the adoption of distributed NEM.	Utility transmission, and distribution loss factors, i.e., expansion factors, as reported in their respective approved Tariffs. Generation losses are already accounted for in the energy costs.
	Capacity	Reduction in the fixed costs of building and maintaining new conventional generation resources associated with the adoption of distributed NEM.	The DPS ICAP model attached to the July 1, 2015 DPS BCA White Paper was used to forecast future installed capacity (ICAP) prices appropriate under a load modification approach applicable to each utility. These capacity costs are also adjusted for the appropriate energy T&D losses as well as adjusted by the expected system peak load reduction value realized by each type of NEM technology.
	Ancillary Services	Reduction of the costs of services like operating reserves, voltage control, reactive power, and frequency regulation needed for grid stability associated with the adoption of distributed NEM.	A proxy value of 1% assigned. The NYISO procures ancillary services on a fixed rather than load following basis based on a largest single contingency measure, which means the amount of ancillary services procured would not likely decrease in any appreciable way due to the adoption of distributed NEM. There could be some benefit from voltage/reactive power control or power factor correction with newly enabled smart inverter technology.
	Transmission Capacity	Reduction or deferral of costs associated with expanding/replacing/upgrading transmission capacity associated with the adoption of distributed NEM.	The value of transmission capacity is captured in the NYISO CARIS zonal production simulation modeling results and is represented as congestion, i.e., energy price differentials, between the NYISO modeled zones. It is also likely captured to some extent in the various zonal NYISO capacity prices, i.e., more transmission and generation constrained capacity zones would likely have a higher zonal capacity price all else being equal.
	Sub-Transmission Capacity	Reduction or deferral of costs associated with expanding/replacing/upgrading sub-transmission capacity such as substations, lines, transformers, etc. with the adoption of distributed NEM generation.	Costs based on existing estimates for marginal sub-transmission capacity costs as provided by each utility in their Marginal Cost of Service Studies. These costs are adjusted by the expected sub-transmission system peak load reduction value realized by each type of NEM technology based on NYISO zonal load data.
	Distribution Capacity	Reduction or deferral of costs associated with expanding/replacing/upgrading distribution capacity such as lines, transformers, etc. with the adoption of distributed NEM generation.	Costs based on existing estimates for marginal distribution capacity costs as provided by each utility in their Marginal Cost of Service Studies. These costs are adjusted by the expected distribution system peak load reduction value realized by each type of NEM technology based on utility sample substation load data.

Cost Test Criteria	Component	General Description	Initial Study Calculation Methodology/Proxy Value
	Criteria Pollutants	Reduction of SO_2, ad NO_x emissions due to reduction/increase in production from the marginal wholesale generating resources associated with the adoption of distributed NEM generation.	The compliance costs associated with these criteria pollutants is included in the zonal energy cost NYISO CARIS forecasts.
	Financial CO_2 Emissions Cost	Reduction of CO_2 emissions due to reduction in production from the marginal wholesale generating resources associated with the adoption of distributed NEM generation.	The financial value of carbon as determined by the NYISO in its CARIS forecast.
	Market Price Effect	Potential reduction of system wide wholesale energy costs due to reduced system load attributable to distributed NEM generation.	There are many factors that affect this component including how much the current and forecast NY wholesale energy market is at spot vs. hedged or under long-term contracts. Additionally information on the underlying market and operational characteristics are needed to see how much if any supply can be affected and for how long due to distributed NEM PV generation now and in the future. E3 identifies this component explicitly as one requiring further study but a proxy value was calculated using the NYISO high solar PV case as part of its CARIS I study[56]. An average LBMP market price effect was calculated to be approximately \$15.0/MWh for each incremental MWh of solar generation on a statewide basis after adjusting for the amount of the day-ahead market assumed to be hedged (~40%). This effect is assumed to decrease by 50% in the following year to \$7.5/MWh and then to zero in the 3rd year as per the guideline in the DPS BCA.
Utility or Ratepayer Costs	Utility Integration Costs	Increase of costs borne by the utility to interconnect and integrate distributed NEM including increases in ancillary services like operating reserves, voltage control, etc.	This can be examined most easily based on detailed studies and/or literature reviews[57] that have examined the costs of integration and interconnection associated with the adoption of NEM. An assumed value of \$1-\$3/MWh is used in this analysis depending on the scenario.
	Program Costs	Increase of costs borne by the utility to administer NEM customers.	Incremental costs associated with NEM such as billing of net metering customers as well as other administrative costs. An assumed value of \$1-\$3/MWh is used in this analysis depending on the scenario.
	State Incentive Costs	Costs borne by the ratepayers to incent the NEM-eligible technologies.	All MW Block Incentive costs are assumed to be paid for by all ratepayers through the current/future System Benefit/RPS/Public Purpose Charges in the year the incentives are disbursed. These revenues are based on volumetric rates and customer usage. In this analysis this value is assumed to be the planned MW Block Incentives applied 2015-2023.

[56] http://www.nyiso.com/public/webdocs/markets_operations/committees/bic/meeting_materials/2015-08-12/agenda%203%20Market%20Operations%20Report_%20BIC_08.12.15.pdf

[57] A topical report is a Duke Energy/US Department of Energy study of solar integration in the Carolinas available at http://www.duke-energy.com/pdfs/carolinas-photovoltaic-integration-study.pdf.

Cost Test Criteria	Component	General Description	Initial Study Calculation Methodology/Proxy Value
Bill Savings (Utility Revenue Loss)	NEM Customer Bill Savings	These are the direct savings on a customer's bill which also represent the utility's lost revenue as a result of installing net metered solar PV onsite.	E3 estimated these values based on publicly available marginal customer billing data from NYSERDA's Clean Power Research Tool for average residential, commercial, and industrial customers[58].
Federal/State Tax Credits	Federal/State Tax Credits	The federal investment tax credit along with any in state tax credits used to incentivize distributed solar.	The federal investment tax credit along with any other state tax credits will be modeled as incentives for solar PV systems over the analysis forecast period.
NEM Generation Costs	NEM System Costs	The costs to build and/or finance distributed NEM generation systems over time.	E3 created New York specific NEM installation and cost forecasts based on current pricing and future expected technology and cost declines. All NEM system costs from 2015-2025 were modeled with an E3 financial pro formal model as a third party owned system under a PPA/lease if appropriate.
Discount Rate and Levelization Approach		Annual rate used to discount various types of future value or cost streams to present values.	A 5.5% real discount rate is used for all benefits and cost streams with an assumed long-term inflation rate of 2%. A real economic, i.e., constant real, levelization approach is used rather than a nominal levelization to better allow for annual snapshot comparisons of NEM benefits and costs.

2.1.4.2 Non-Financial Benefits and Costs Affecting New York and New York Ratepayers (Societal Externalities)

The following table describes the non-financial societal benefits of GHG mitigation and improved air quality.

Figure 17: Detailed Description of the NEM Non-financial Benefit-Cost Components

Cost Test Criteria	Component	General Description	Initial Study Calculation Methodology/Proxy Value
Societal Benefits	Social Carbon (Societal Benefits)	Changes in agricultural productivity, human health impacts, property and infrastructure damages from increased flood risk, and the value of ecosystem service losses due to climate change.	E3 identifies this component explicitly as one requiring further study in order to establish the appropriate New York specific social carbon or societal benefit applicable in this analysis. For the purpose of this study the EPA social cost of carbon was relied upon[59] minus the financial CO_2 emission cost forecast from the NYISO CARIS. This EPA forecast assumes different levels of discount rates to determine the cost of carbon. The emission rate was determined by using EPA eGrid data[60] for NY specific generators to determine average annual marginal emission rates for natural gas, oil, and coal plants

[58] http://ny-sun.ny.gov/Get-Solar/Clean-Power-Estimator
[59] http://www.epa.gov/climatechange/EPAactivities/economics/scc.html
[60] http://www.epa.gov/cleanenergy/energy-resources/egrid/

Cost Test Criteria	Component	General Description	Initial Study Calculation Methodology/Proxy Value
			along with information on which of these fuels were on the margin based on the NYISO State of the Market report[61].
	Health Benefits	Reduction of non-emission related health benefits such as decreased mortality rates, reduced asthma attacks, etc. associated the adoption of distributed solar.	These externalities are often difficult to estimate. E3 identifies this component explicitly as one requiring further study in order to establish the appropriate New York specific externalities that should be examined. For the purpose of this study high level estimates from the EPA for the costs of SO_2 and NO_x related health impacts are used. These estimates assume different levels of discount rates to determine the damage values, which are used in conjunction with the marginal emission rates of SO_2 and NO_x derived from the EPA's eGrid data similar to the methodology described above for CO_2 emissions.

2.1.4.3 Other Potential Benefits and Costs

There are some categories of benefits and costs that exist in the literature as well as mentioned in the DPS BCA White Paper that were not quantified for a variety of reasons:

+ They are very small and uncertain;
+ They are included in other components; or,
+ They are outside the scope of this analysis.

The following are potential additional benefits and costs in addition to what was explicitly examined in this study:

+ RPS Value
    - In many jurisdictions there is often a benefit with NEM installations that can reduce the obligation of the utility to purchase renewables to meet state RPS compliance requirements, which is a potential avoided cost benefit.
    - In New York the RPS program is structured uniquely compared to other states where in New York funds are used to procure renewables and the RPS targets are non-binding with no financial penalty or costs for non-compliance.

[61] http://www.nyiso.com/public/webdocs/markets_operations/documents/Studies_and_Reports/Reports/Market_Monitoring_Unit_Reports/2014/NYISO2014SOMReport__5-13-2015_Final.pdf

- Therefore no savings are assumed to occur due to NEM system adoptions.

+ Fuel Hedge
  - Reduction in costs of locking in future price of fuel associated with the adoption of distributed NEM.
  - There are many factors that affect this component including how much exposure the current and forecast New York generation fleet has to natural gas or other fuels on a marginal basis as well as determining how much of New York's energy requirements are hedged with long-term contracts.
  - Additional information on the underlying market differentials between spot and future fuel/electricity prices needs to be determined.
+ Net Economic Impacts
  - Any incentives paid to particular programs are expected to generate economic activity, which should be balanced against the costs of those programs.
  - Given the likely adoption of NEM systems it is expected that this will lead to net economic benefits[62].
  - These benefits may inform policy and be an ancillary consideration, but are not typically directly included in any industry standard 'cost tests'.
+ Security/Resiliency
  - Benefits based on increasing system resiliency or security by reducing restoration and/or outage costs.
  - Some portion of restoration costs are already included in the avoided sub-transmission and distribution capacity costs directly financial and paid for by ratepayers.
+ Other
  - Other benefits include, but are not necessarily limited to, such things, employee productivity, property values, reduction of the effects of termination of service and avoidance of uncollectible bills for utilities.

[62] Please see an earlier NYSERDA study (**http://www.nyserda.ny.gov/-/media/Files/Publications/Energy-Analysis/NY-Solar-Study-Report.pdf**) looking at job and employment impacts of solar PV deployment. Specifically the study looked at installing 5,000 MW by 2025. The Low Cost scenario, which corresponds most closely with the observed level of actual solar PV cost declines state the creation of 700 net jobs economy-wide through 2049, which includes both an increase and decrease in jobs.

- As per the DPS BCA it is not expected that these other values will be directly assigned a financial value at this time.

2.2 Income Analysis of Residential NEM Customers

A granular geographic information system (GIS) and census tract[63] income analysis was conducted using a database of approximately 30,000 solar PV installations. In this analysis, we look at the demographics and geography of residential NEM customers using NYSERDA's database of customers that have installed solar PV through a New York State incentive program, which includes installation size, installation cost, installation year, NYISO zone, and customer census tract, combined with American Census Survey (ACS) data from the US Census Bureau[64]. Census tracts are much smaller geographic areas than zip codes (3,000-6,000 households), and they are selected to have more homogenous demographics. Therefore, the use of census tracts allows for more accurate estimates of NEM customer demographics compared to using zip codes.

As the majority of solar PV installations have taken place in the last five-years, the focus in this income analysis focuses on the period between 2010 and 2015. For household income, unless mentioned otherwise, the median income in the corresponding census tract at the year of installation (2010-2015) was assigned to the NEM customer.

[63] https://www.census.gov/geo/reference/gtc/gtc_ct.html
[64] For 2010-2013, ACS 5-year estimates were used; for 2014 and 2015 the ESRI Demographic Updated Database was used (http://www.esri.com/data/esri_data).

3 Results

3.1 Current New York NEM Installations

The following section presents the results from our study analysis. As can be seen in the figures below NEM has been an important driver of increased adoption of distributed renewable generation in New York. There have been significant increases in NEM system installations recently as well as a queue, i.e., 'pipeline' of future projects.

Figure 18: Cumulative Residential Solar PV Installations by NYISO Zone in 2013 vs. 2015

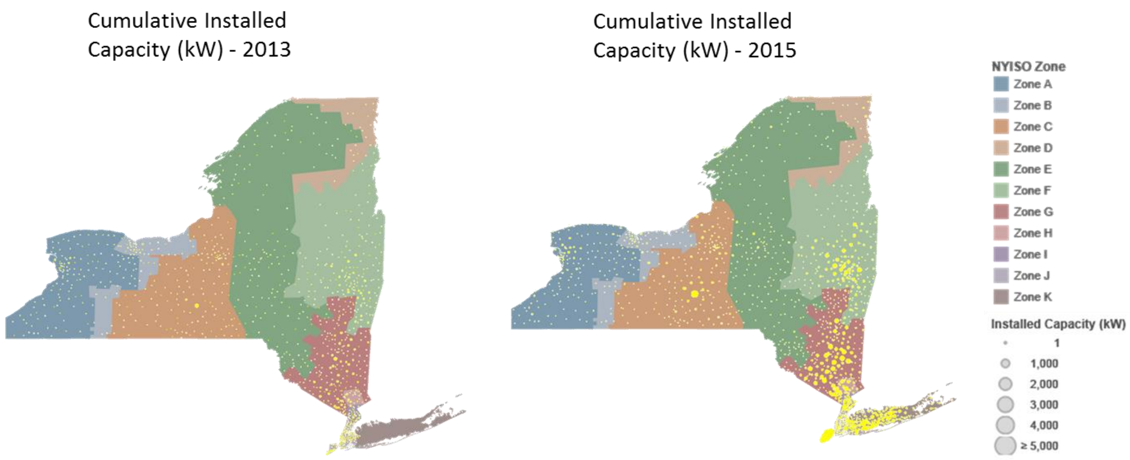


Figure 19: Cumulative Solar PV Installations in 2015 by NYISO Zone (Residential vs. Non-Residential)

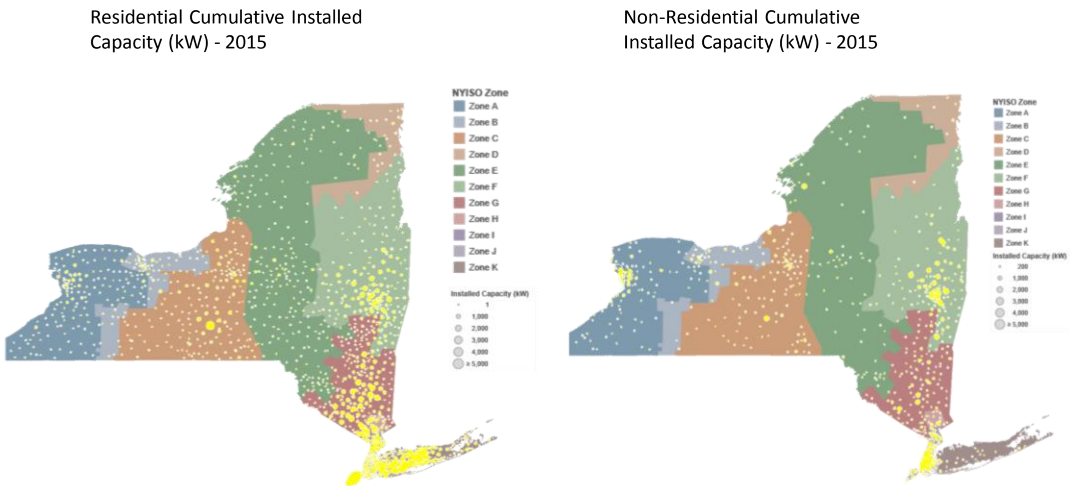
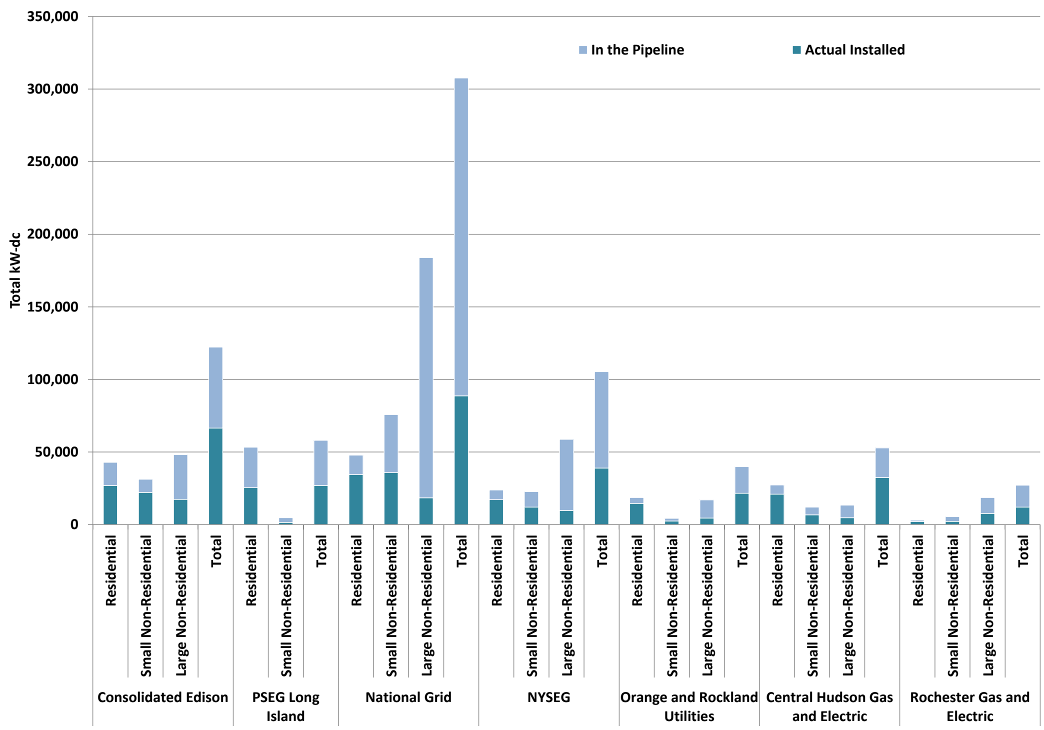


Figure 20: Solar PV Installations either Currently Installed or Installations that have Applied for MW Block Incentives and are in the Queue to be Built



3.2 Solar PV Block Assumptions

To evaluate the statewide costs and benefits of NEM, we examine 500 MW of NEM systems adopted in 2015, proportional to the MW Bock Targets between regions, utilities and customer classes.

Figure 21: Proposed Buildup Based on MW Block Targets with Upstate Targets Allocated to Each Utility Based on Existing Distribution of Solar PV Installations

Utility/Class	Residential	Small-Non-Residential	Large Non-Residential	TOTAL
ConEd	8.2%	8.2%	11.5%	27.9%
PSEG Long Island	3.3%	1.6%	0.0%	4.9%
National Grid	4.8%	7.7%	27.1%	39.6%
NYSEG	2.4%	2.3%	8.6%	13.3%
ORU	1.9%	0.4%	2.5%	4.8%
Central Hudson	2.7%	1.2%	2.0%	5.9%
RG&E	0.3%	0.6%	2.7%	3.6%
TOTAL	**23.5%**	**22.0%**	**54.5%**	**100.0%**

3.3 Scenario Assumptions

We developed four scenarios for evaluating the benefits and costs of the NEM system installations. These four scenarios are designed to capture the range of potential values of the underlying benefit and cost components given the inherent uncertainty with quantifying these values. Specific assumptions are presented below.

One thing to note is that the middle two scenarios only differ in the treatment of targeting NEM systems to higher value locations on the distribution grid, i.e., if NEM systems were simply placed in higher value locations its value would be higher, all else being equal.

Figure 22: High Level Scenario Descriptions

NEM Scenarios	
Lower NEM Value	Untargeted and Expensive Solar, Low Utility Avoided Costs, Less Value for GHG Mitigation and Improved Air Quality, and Higher T&D Delivery Rates
Untargeted NEM (Business as Usual)	'Distribution Value'[65] is Under Lock and Key and NEM is Untargeted = Lower Benefits to the Grid
Targeted NEM	'Distribution Value' is Unlocked and NEM is 'Smarter' and Targeted to Maximize Value to the Grid
Higher NEM Value	Better 'Distribution Value' than Expected with 'Smarter' and Cheaper Solar, Higher Utility Avoided Costs, More Value for GHG Mitigation and Improved Air Quality, and Lower T&D Delivery Rates

[65] Defined as the distribution level benefits of distributed energy resources like NEM-eligible systems.

Figure 23: Summary of Scenario Input Assumptions

	Lower NEM Value	Untargeted NEM	Targeted NEM	Higher NEM Value
Energy & Losses	-10%	Base	Base	+10%
Monetized Carbon	-15%	Base	Base	+15%
Ancillary Services	Base	Base	Base	Base
Generation Capacity Prices	Low	Base	Base	High
Generation Capacity Value	-10%	Base	Base	+10%
Transmission Capacity	None	None	None	None
Sub-Transmission Capacity Avoided Costs	None	Base	Base	Base
Sub-Transmission Capacity Demand Reduction Realization	0%	20%	100%	120%
Distribution Capacity Avoided Costs	None	Base	Base	Base
Distribution Capacity Demand Reduction Realization	0%	20%	100%	120%
Integration Costs	High	Base	Base	Low
Program Costs	High	Base	Base	Low
NEM Capital Costs	High	Base	Base	Low
T&D Retail Rate	High	Base	Base	Low
CO2, SO2, and Nox Emission Rates	-5%	Base	Base	+5%
Social Cost of Carbon	Low	Base	Base	High
Health Benefits (SO2 and Nox)	Low	Base	Base	High
Market Price Effect	None	Base	Base	Base
Reactive Power	None	None	None	None
Resiliency/Restoration	None	None	None	None
Other	None	None	None	None

3.4 Results

3.4.1 'VALUE OF SOLAR' RESULTS

The total 'value' or benefits from distributed solar PV increases over time (2015 vs. 2025) in all scenarios as both the direct financial and non-financial environmental or societal benefits from solar PV increase from current levels, i.e., utility avoided costs and social carbon costs are forecast to increase over time, although in the Targeted NEM Scenario more distribution and sub-transmission avoided cost benefits are achieved by assuming that NEM systems are sited at higher value locations on the distribution grid.

Figure 24: 'Value of Solar', Untargeted NEM Scenario, Statewide, All Classes, Solar PV

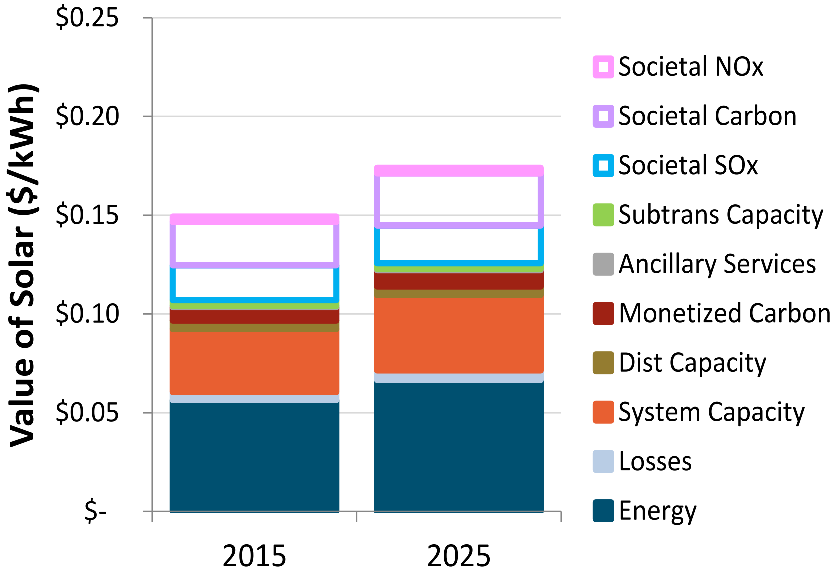
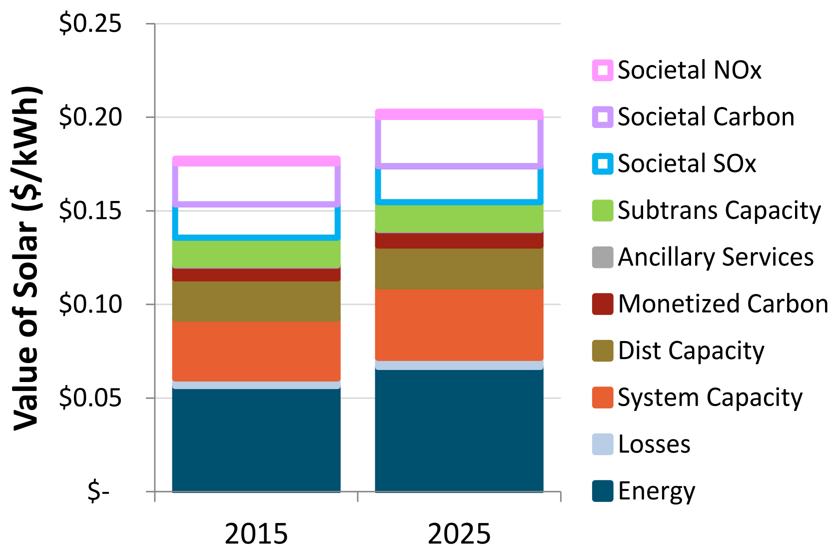
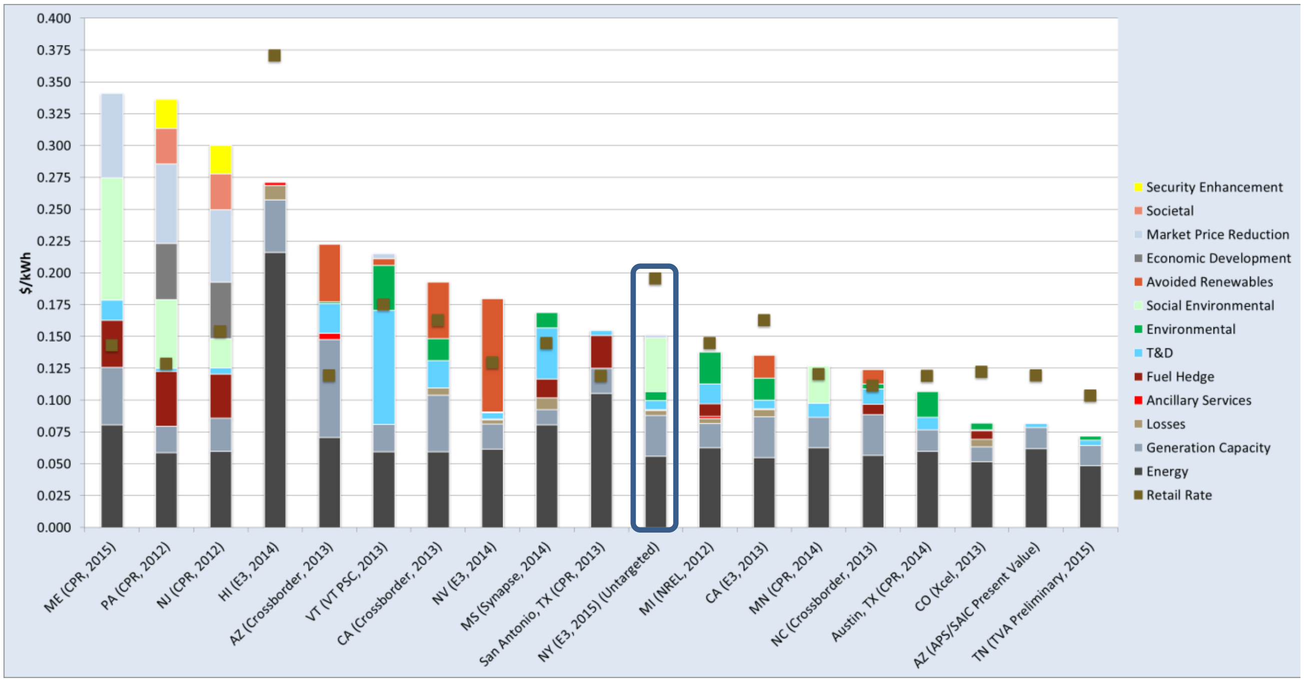


Figure 25: 'Value of Solar', Targeted NEM Scenario, Statewide, All Classes, Solar PV



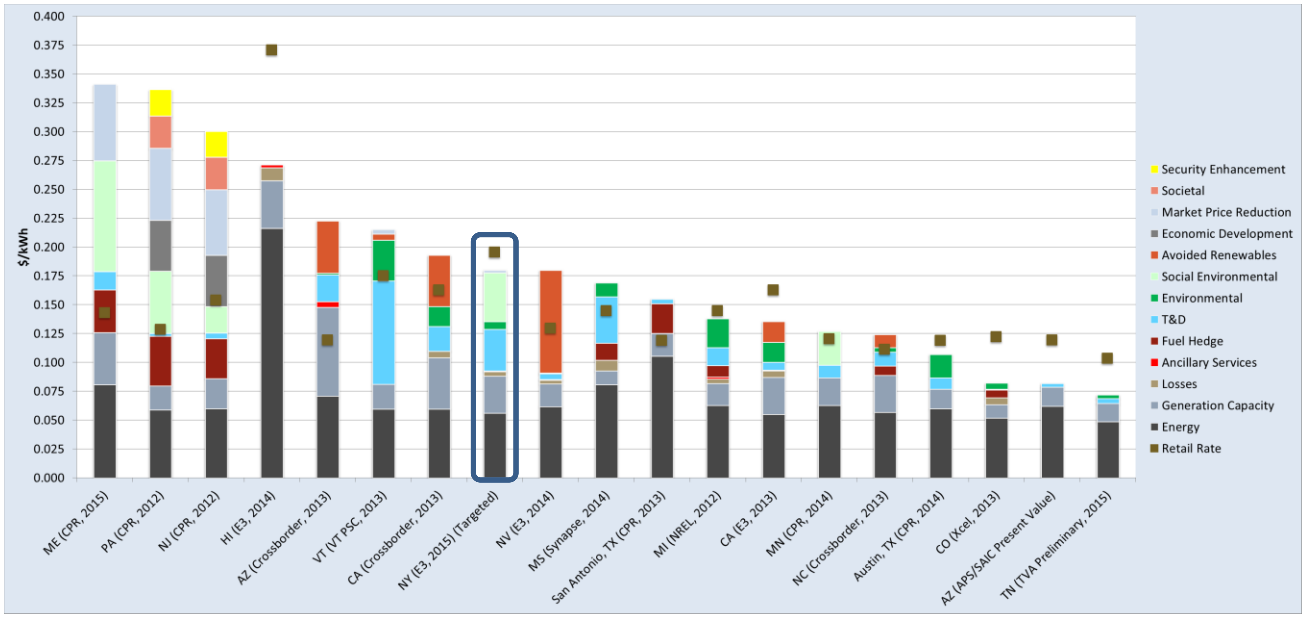
The 'value of solar' calculated in this study across our four defined scenarios is a result unique to New York based on the characteristics of the underlying electric system costs and other specific attributes, but it is worth noting that this total 'value' is in the range of values found in other national studies.

Figure 26: Levelized[66] Value of Solar and NEM Benefit-Cost Studies Including Untargeted NEM or 'Business as Usual' Scenario Results[67] Including Both Financial and Non-Financial Benefits



[66] Solar benefits, i.e., 'value of solar' are levelized over an assumed 25-year system life. The levelization period in other studies can vary.
[67] Distribution and sub-transmission avoided capacity cost benefits are grouped together in the 'T&D' category. Financial carbon costs are assigned to the 'Environmental' category. Non-financial quantified environmental impacts from SO_2 and NOx along with Social Carbon Costs are assigned into the 'Societal' category.

Figure 27: Levelized Value of Solar and NEM Benefit-Cost Studies Including Targeted NEM Scenario Results Including Both Direct and Non-Financial Benefits



We present below another 'value of solar' perspective that is 'layered' by comparing any monetary net expenses of NEM to non-participants against both the direct financial benefits and the non-financial societal benefits to create another 'value of solar' perspective. It is worth noting that this perspective is not a 'cost test' to examine the financial impacts to non-participating ratepayers, which could be performed under a Ratepayer Impact Measure per industry standard practice.

The value of distributed solar PV, i.e., the 'value of solar', based on direct financial benefits ranges from \$0.08 to \$0.16 per kWh of assumed solar PV production on a real[68] levelized basis for NEM systems installed in 2015 across our four defined scenarios (Lower NEM Value to Higher NEM Value). When adding in the quantified non-financial societal benefits (these range from \$0.02 to \$0.07 per kWh of assumed solar PV production) then the total 'value of solar' ranges from \$0.10 to \$0.23 per kWh.

[68] A 2% inflation rate is assumed when determining the real economic levelization over the 25-year lifetime of the NEM systems.

The difference between the ‘value of solar’ and the ratepayer expenses of NEM generation (including bill savings, state incentives and NEM integration/program costs) ranges from -$0.08 to $0.05 per kWh of assumed solar PV production on a levelized basis for NEM systems installed in 2015 across the four defined scenarios examined (Lower NEM Value to Higher NEM Value).

Figure 28: Layered ‘Value of Solar’ Perspective of NEM Ratepayer Expense vs. Total Financial and Non-Financial Benefits, Lower NEM Value Scenario, 2015 Vintage, Statewide, All Classes, Solar PV

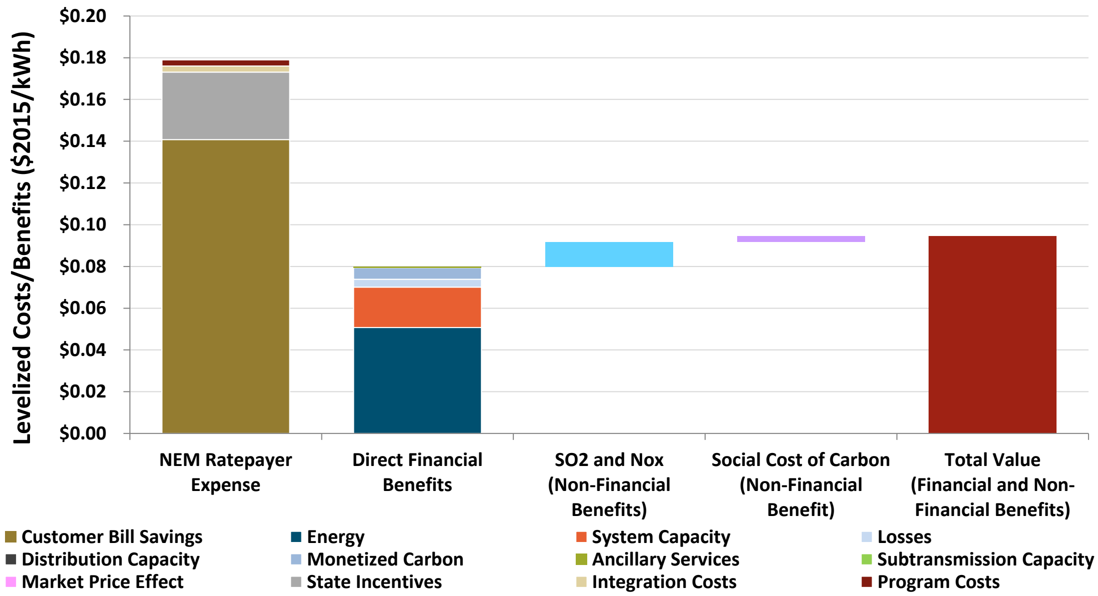


Figure 29: Layered 'Value of Solar' Perspective of NEM Ratepayer Expense vs. Total Financial and Non-Financial Benefits, Untargeted NEM Scenario, 2015 Vintage, Statewide, All Classes, Solar PV

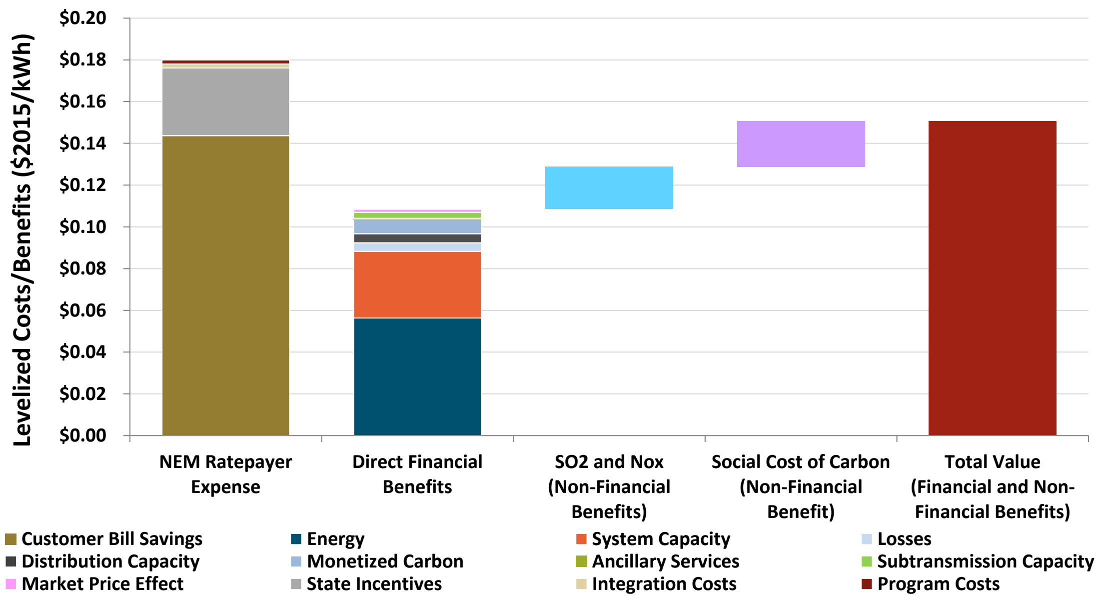


Figure 30: Layered 'Value of Solar' Perspective of NEM Ratepayer Expense vs. Total Financial and Non-Financial Benefits, Targeted NEM Scenario, 2015 Vintage, Statewide, All Classes, Solar PV

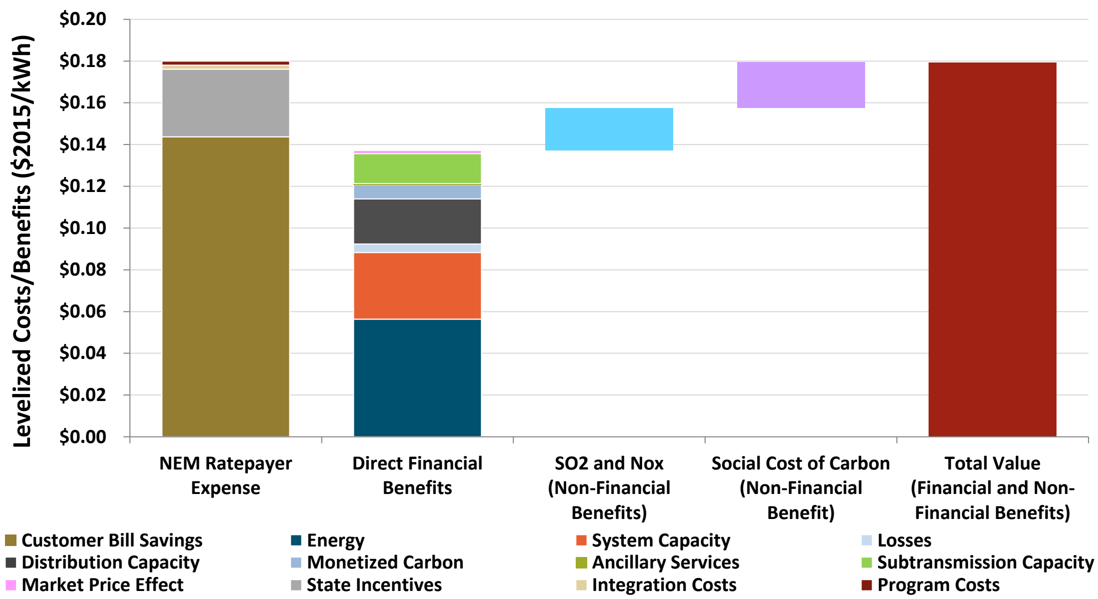
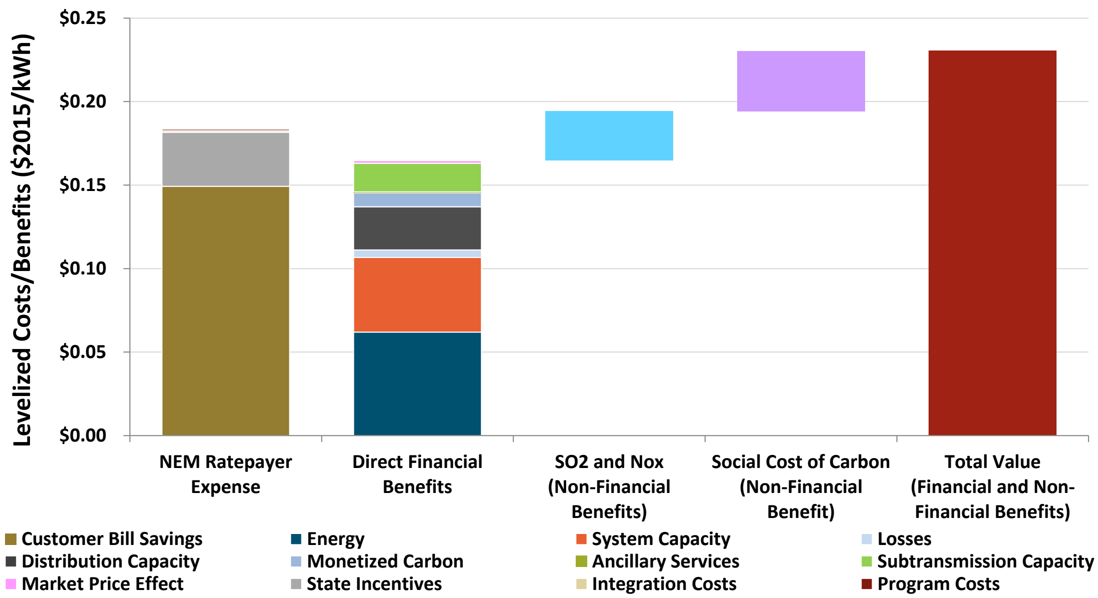


Figure 31: Layered 'Value of Solar' Perspective of NEM Ratepayer Expense vs. Total Financial and Non-Financial Benefits, Higher NEM Value Scenario, 2015 Vintage, Statewide, All Classes, Solar PV



Ratepayer expenses of NEM generation (including bill savings, state incentives and NEM integration and program costs) range between $0.05 to $0.08 per kWh higher than the 'value of solar' between Upstate (National Grid, ORU, RG&E, NYSEG, Central Hudson) and Downstate (ConEd and PSEG Long Island) for NEM systems installed in 2015 in the Untargeted NEM Scenario. These results do improve over time when looking at installations in 2025 due to lower NEM installation costs and higher NEM value.

Figure 32: Layered 'Value of Solar' Perspective of NEM Ratepayer Expense vs. Total Financial and Non-Financial Benefits, Upstate Utilities-Untargeted NEM Scenario, 2015 Vintage, All Classes, Solar PV

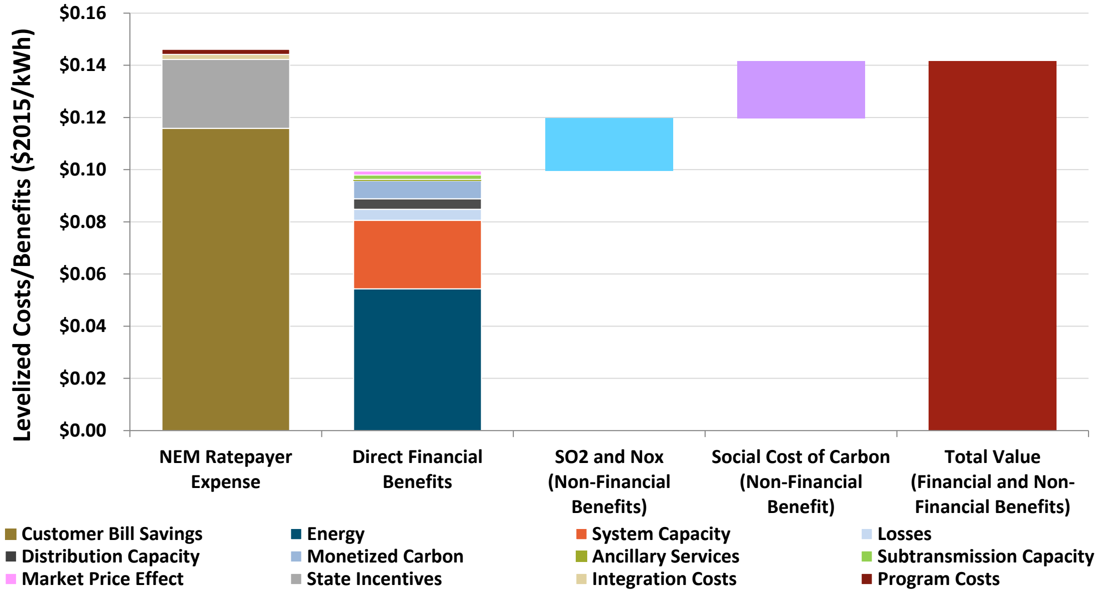
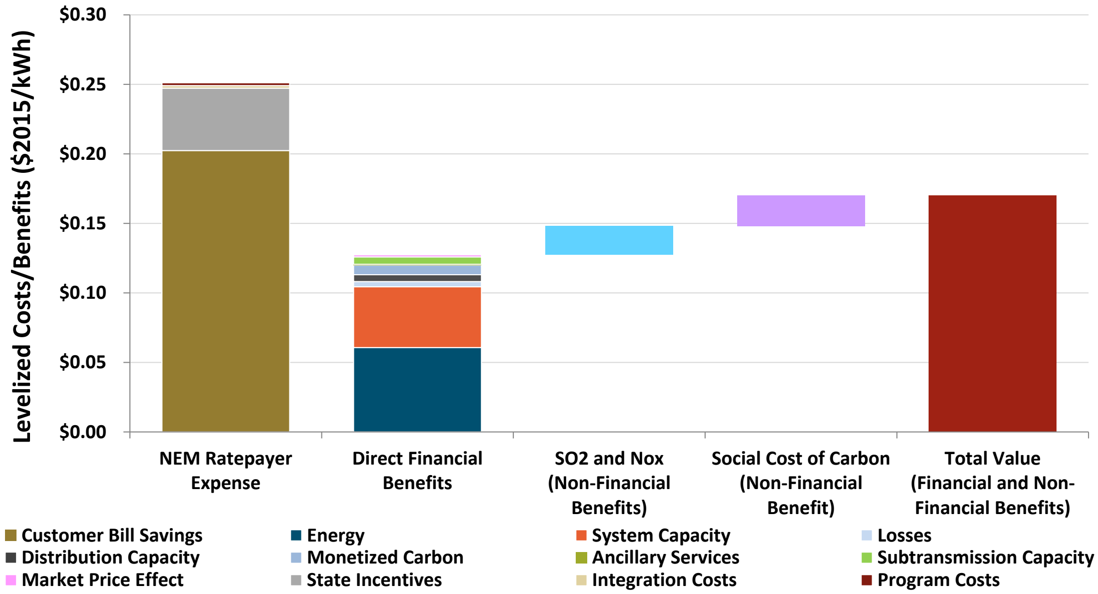


Figure 33: Layered 'Value of Solar' Perspective of NEM Ratepayer Expense vs. Total Financial and Non-Financial Benefits, Downstate Utilities-Untargeted NEM Scenario, 2015 Vintage, All Classes, Solar PV



The difference between the ratepayer expenses of NEM generation (including bill savings, state incentives and NEM integration/program costs) and the ‘value of solar’ from $0.01 to $0.09 per kWh of assumed solar PV production on a levelized basis between non-residential and residential customers for NEM systems installed in 2015 in the Untargeted NEM Scenario.

Figure 34: Layered ‘Value of Solar’ Perspective of NEM Ratepayer Expense vs. Total Financial and Non-Financial Benefits, Non-Residential Class -Untargeted NEM Scenario, 2015 Vintage, Statewide, All Classes, Solar PV

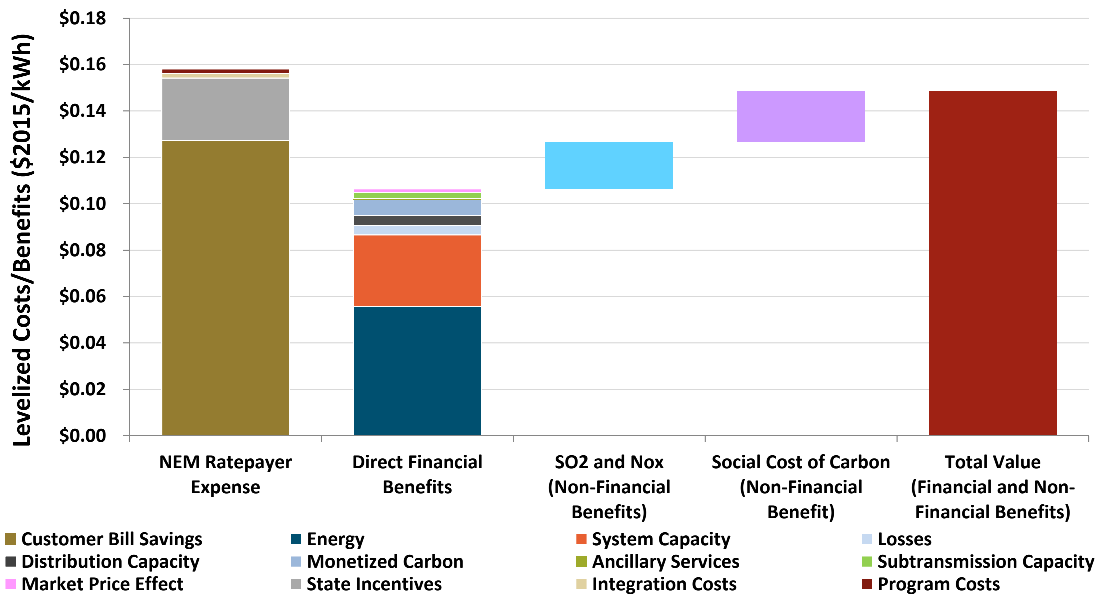
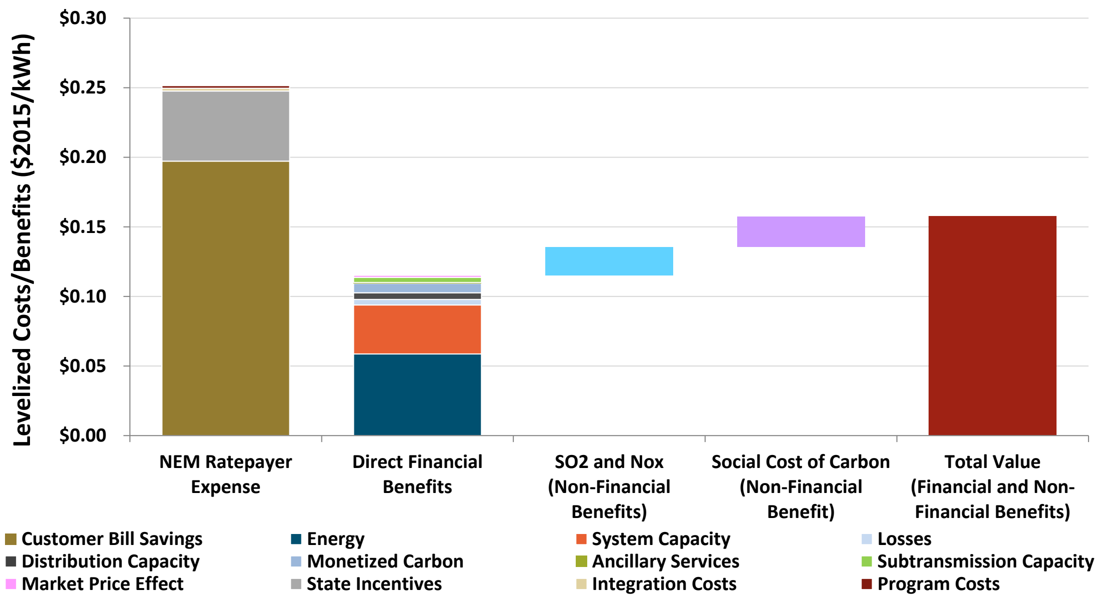


Figure 35: Layered 'Value of Solar' Perspective of NEM Ratepayer Expense vs. Total Financial and Non-Financial Benefits, Residential Class-Untargeted NEM Scenario, 2015 Vintage, Statewide, All Classes, Solar PV



3.4.2 BENEFIT-COST ANALYSIS RESULTS

3.4.2.1 Scenarios

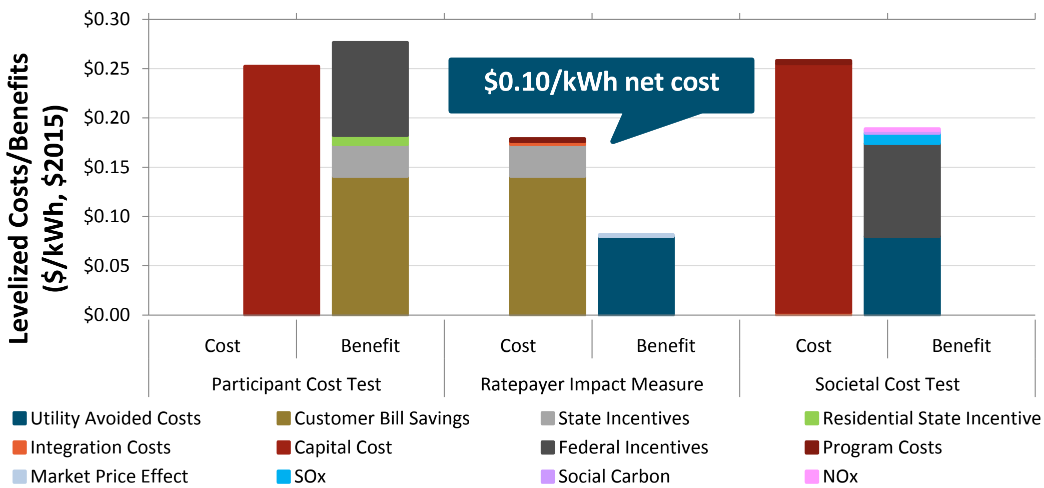
There is an annual net cost to non-participants of the NEM policy[69] that ranges from $10 million to $60 million across our four defined scenarios ($38 million for the Untargeted Case) for the 500 MW of NEM systems in 2015. This represents the annual net cost for the 2015 snapshot year, based on aggregate results over all utilities and customer classes and is due to both the MW Block Incentive and the NEM programs.

[69] In 2015, the net costs to non-participating ratepayers include both the costs of the MW Block Incentive program and NEM. Both factors have an effect on rates. For the Untargeted case, if we exclude the MW Block Incentive from net costs, the net impact to non-participants in 2015 is $16 million and $0.03 per kWh of solar production. Across the 4 scenarios, the net impact to non-participants ranges from a net cost of $36 million to a net benefit of $13 million, or from a net cost of $0.06 per kWh of solar production to a net benefit of $0.02 per kWh of solar production.

Statewide levelized[70] results for all cost tests are shown below.

Figure 36: Levelized Costs and Benefits, Lower NEM Value Scenario, 2015 Vintage, Statewide, All Classes, Solar PV

	PCT	RIM	SCT
Benefit-Cost Ratio	1.10	0.45	0.73



[70] The benefits and costs of NEM systems are levelized over the entire kWh production of these systems over an assumed 25-year life. The actual impacts on non-participant rates are much less, on the order of 0.1-0.5% impacts across scenarios, utilities, and customer classes.

Figure 37: Levelized Costs and Benefits, Untargeted NEM Scenario, 2015 Vintage, Statewide, All Classes, Solar PV

	PCT	RIM	SCT
Benefit-Cost Ratio	1.11	0.60	0.95

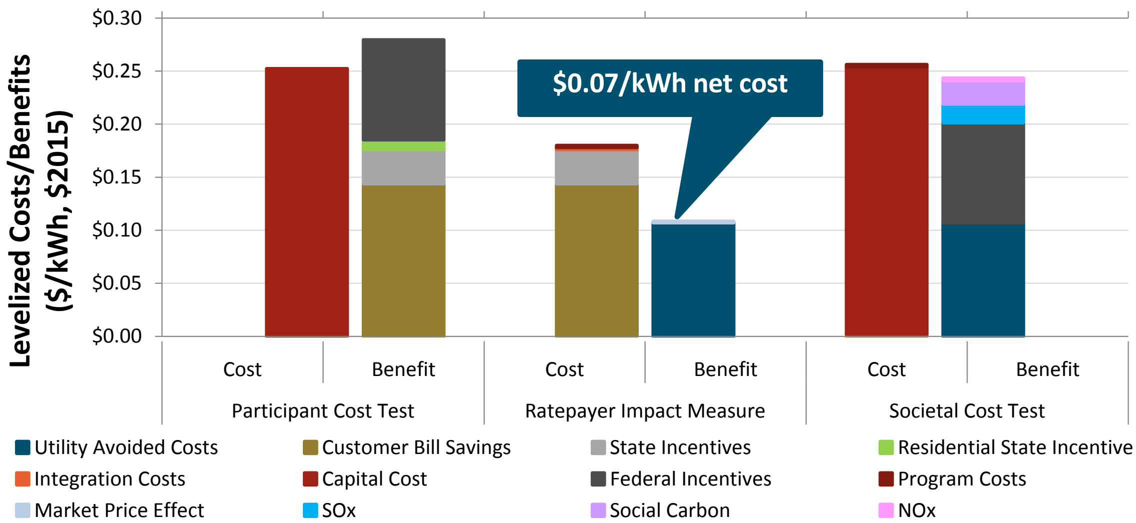


Figure 38: Levelized Costs and Benefits, Targeted NEM Scenario, 2015 Vintage, Statewide, All Classes, Solar PV

	PCT	RIM	SCT
Benefit-Cost Ratio	1.11	0.76	1.06

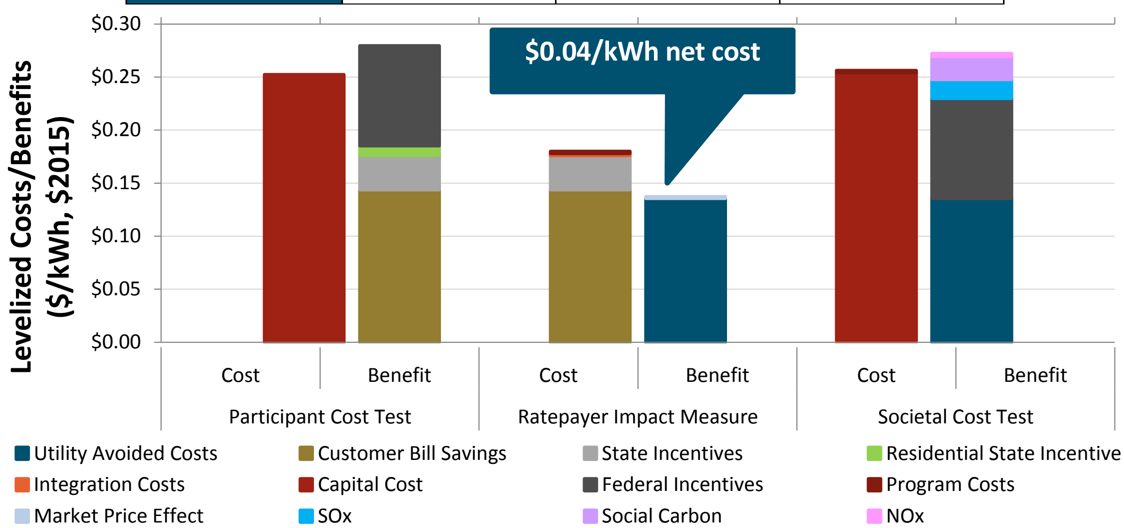
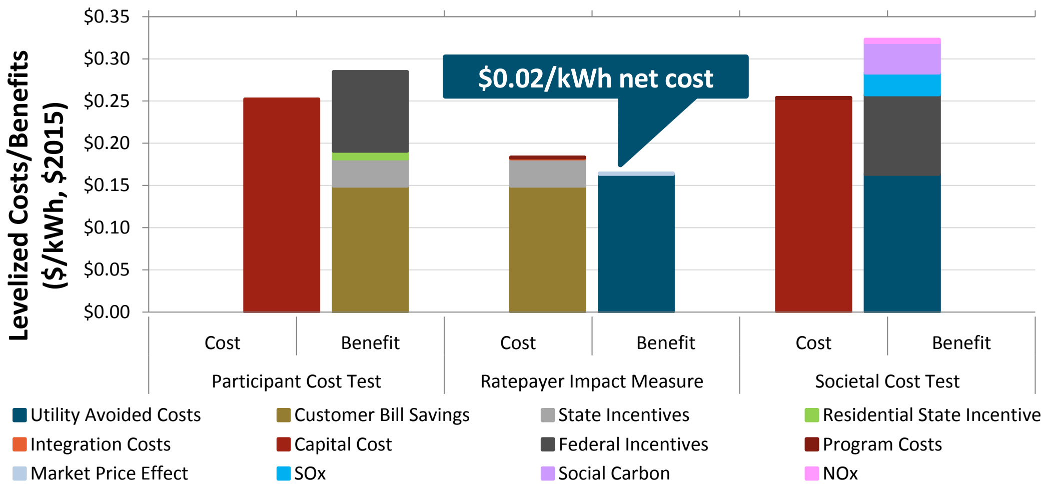


Figure 39: Levelized Costs and Benefits, Higher NEM Value Scenario, 2015 Vintage, Statewide, All Classes, Solar PV

	PCT	RIM	SCT
Benefit-Cost Ratio	1.13	0.90	1.27



3.4.2.2 Downstate vs. Upstate

The net cost is higher for downstate utilities given their higher rates and ranges from $16 million for upstate utilities[71] to $23 million for downstate utilities across all customer classes for NEM systems installed in 2015 in the Untargeted NEM Scenario.

[71] More detailed utility-by-utility results can be found in the Appendix.

Figure 40: Levelized Costs and Benefits Comparison for Downstate vs. Upstate Utilities, Untargeted NEM Scenario, 2015 Vintage, All Classes, Solar PV

	PCT		RIM		SCT	
	Downstate	Upstate	Downstate	Upstate	Downstate	Upstate
Benefit-Cost Ratio	1.23	1.03	0.51	0.68	0.91	0.98

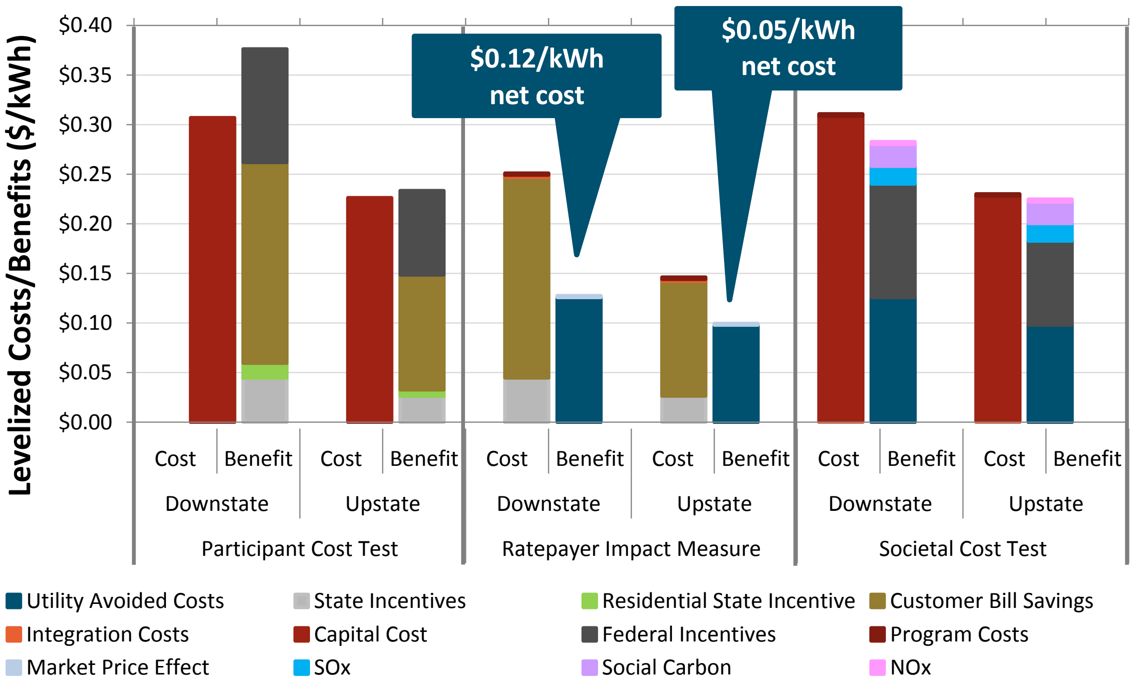
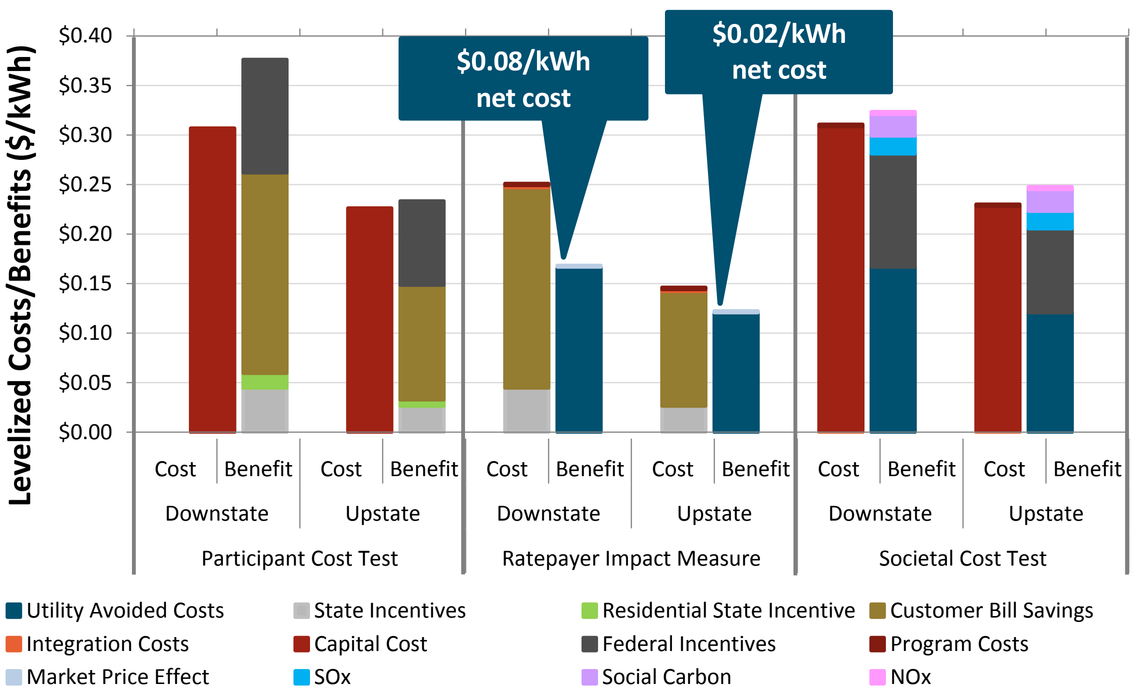


Figure 41: Levelized Costs and Benefits Comparison for Downstate vs. Upstate Utilities, Targeted NEM Scenario, 2015 Vintage, All Classes, Solar PV

	PCT		RIM		SCT	
	Downstate	Upstate	Downstate	Upstate	Downstate	Upstate
Benefit-Cost Ratio	**1.23**	**1.03**	**0.67**	**0.84**	**1.04**	**1.08**



3.4.2.3 2015 vs. 2025 Vintages

The economics for NEM systems are forecasted to improve across the board over time given anticipated increases in technology performance and increases in forecast utility avoided costs from 2015 to 2025.

Figure 42: Levelized Costs and Benefits Comparison for 2015 vs. 2025 Vintages, Untargeted NEM Scenario, Statewide, All Classes, Solar PV

	PCT		RIM		SCT	
	2015	2025	2015	2025	2015	2025
Benefit-Cost Ratio	1.11	1.29	0.60	0.75	0.95	1.25

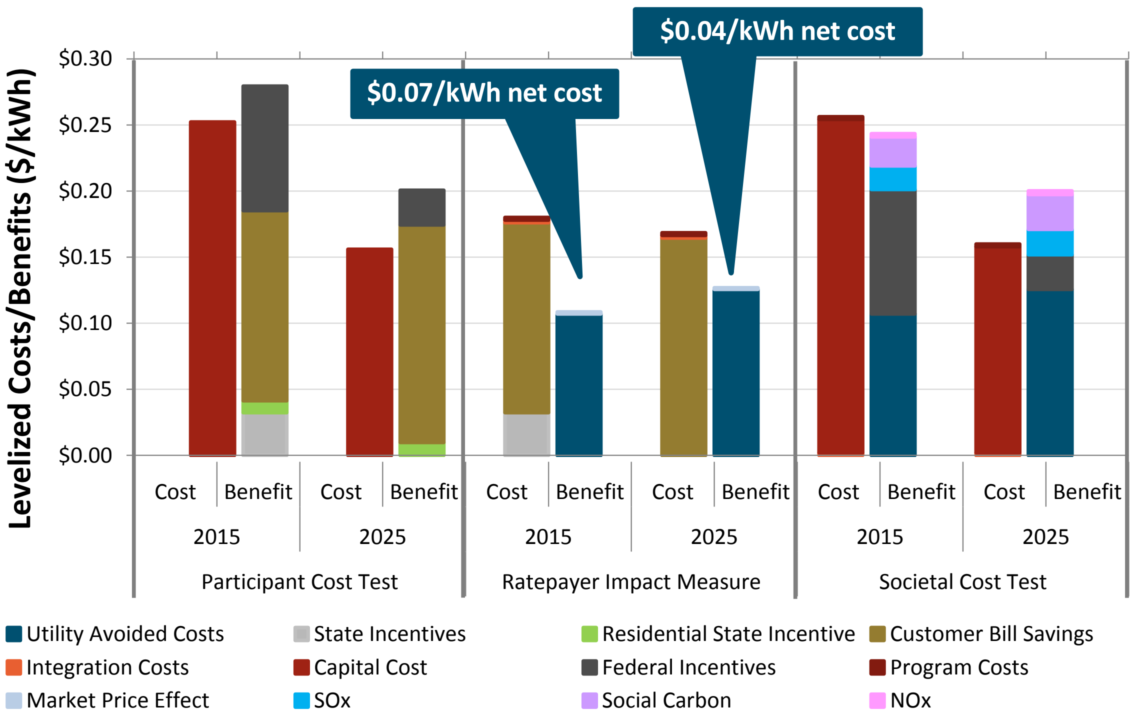
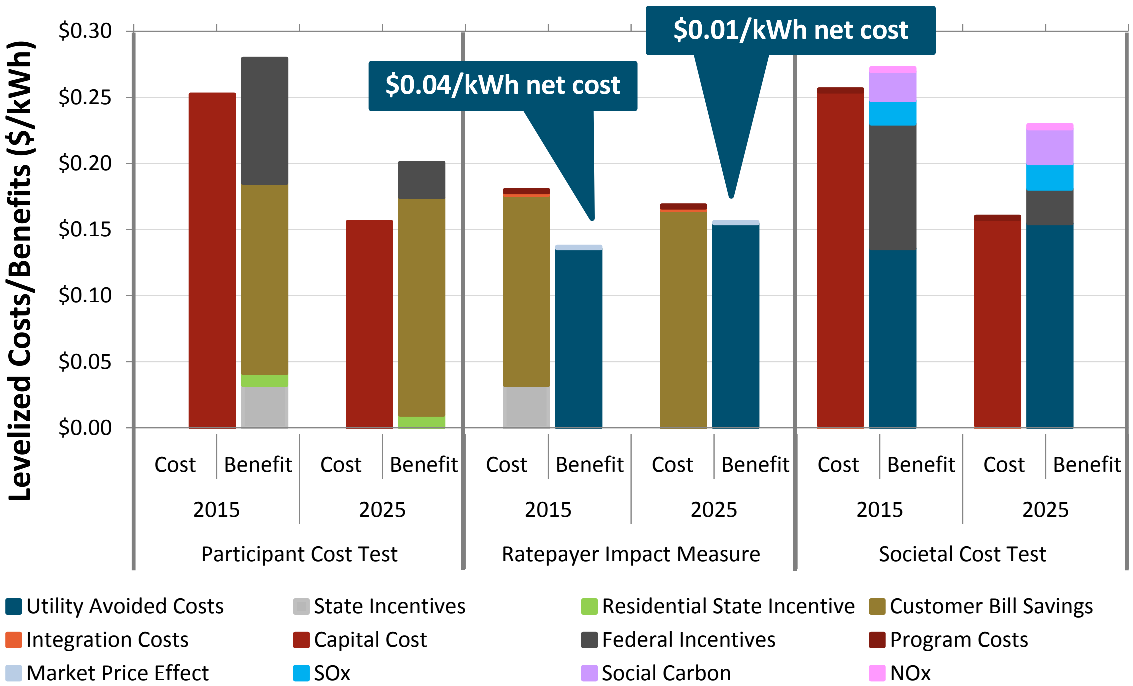


Figure 43: Levelized Costs and Benefits Comparison for 2015 vs. 2025 Vintages, Targeted NEM Scenario, Statewide, All Classes, Solar PV

	PCT		RIM		SCT	
	2015	2025	2015	2025	2015	2025
Benefit-Cost Ratio	1.11	1.29	0.76	0.93	1.06	1.43



3.4.2.4 Customer Classes

NEM systems are most cost effective for participants in the residential and small non-residential classes, but these systems also impose the largest levelized net costs to non-participants which is estimated to be $5 million for large non-residential, $15 million for small non-residential, and $18 million for residential classes in the Untargeted NEM Scenario.

Figure 44: Levelized Costs and Benefits, Residential Class, Untargeted NEM Scenario, 2015 Vintage, Statewide, Solar PV

	PCT	RIM	SCT
Benefit-Cost Ratio	1.19	0.46	0.81

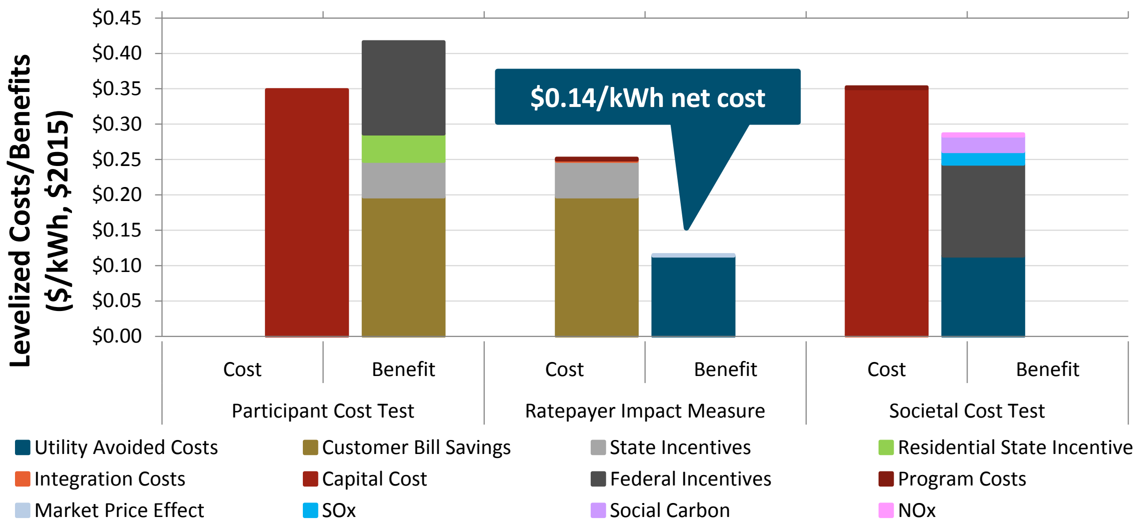


Figure 45: Levelized Costs and Benefits, Small Non-Residential Class, Untargeted NEM Scenario, 2015 Vintage, Statewide, Solar PV

	PCT	RIM	SCT
Benefit-Cost Ratio	1.18	0.47	0.88

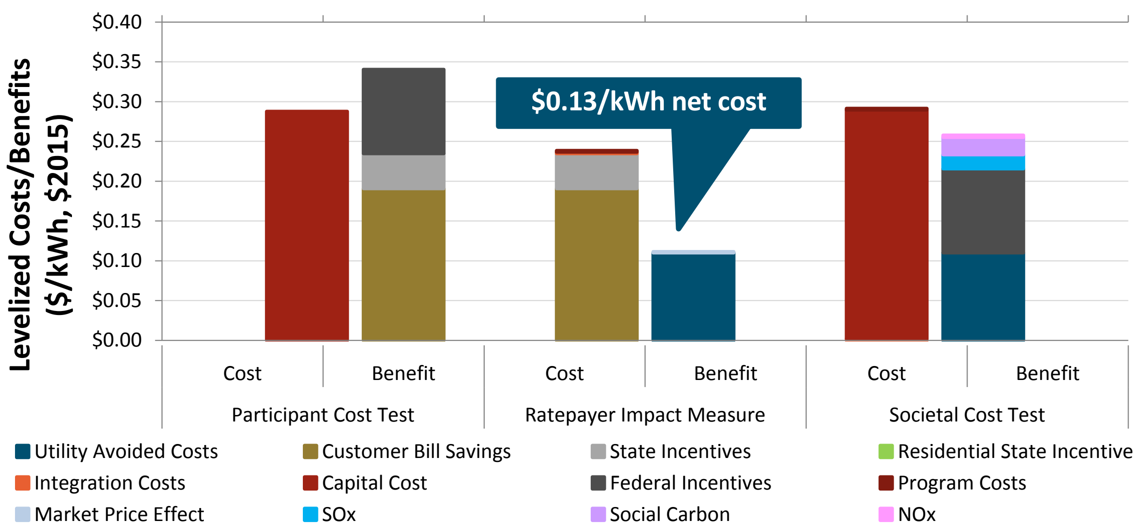
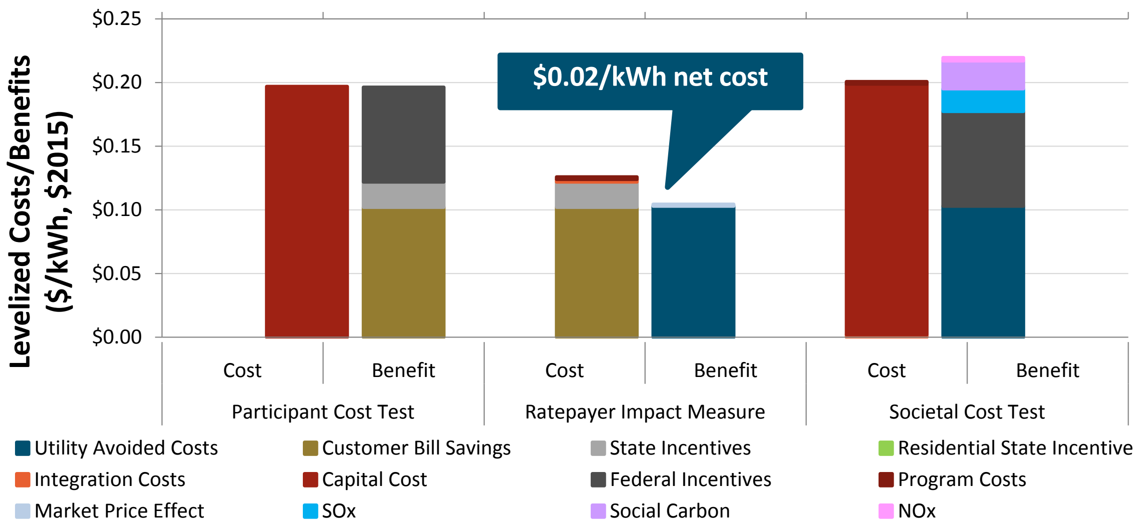


Figure 46: Levelized Costs and Benefits, Large Non-Residential Class, Untargeted NEM Scenario, 2015 Vintage, Statewide, Solar PV

	PCT	RIM	SCT
Benefit-Cost Ratio	1.00	0.83	1.09

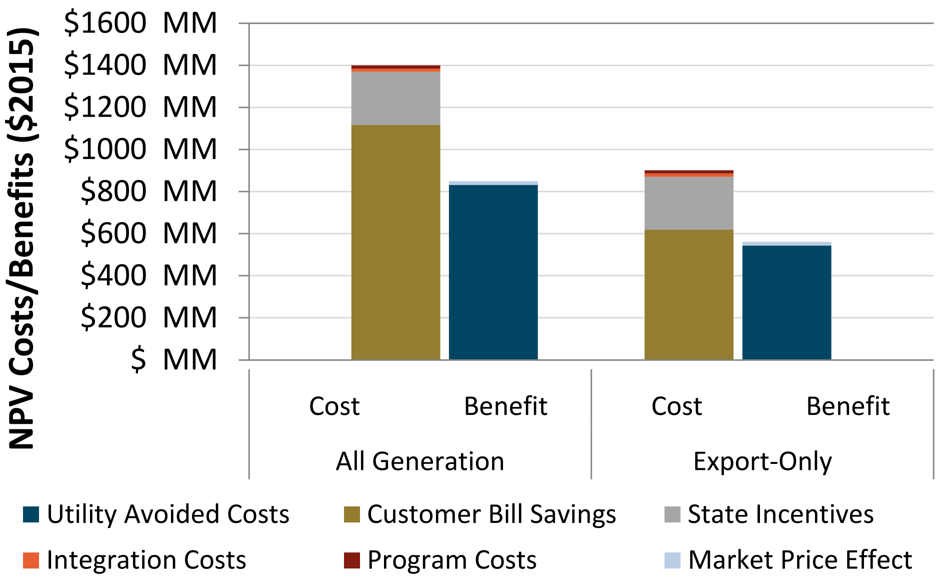


3.4.2.5 Export Only (RIM)

The previous charts measure the costs and benefits of all generation produced by NEM systems including what is consumed behind-the-meter. An alternative perspective is to measure the costs and benefits of energy that is only exported back to the grid and not consumed on-site.

Because the exported energy represents only a fraction of energy production from NEM systems, the total costs and benefits decrease. However, because the avoided cost value of energy exported earlier in the day is less valuable than energy produced in the later afternoon and evening that is consumed behind-the-meter, the total net cost is not greatly impacted by this change in perspective.

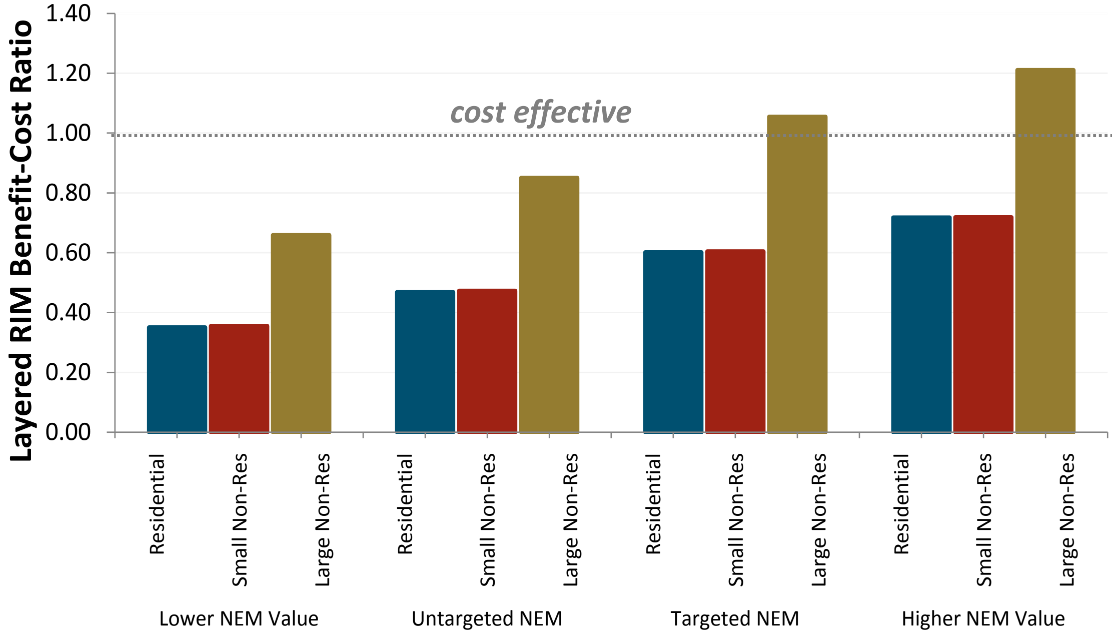
Figure 47: All-Generation vs. Export-Only Ratepayer Impact Measure Results, Untargeted NEM Scenario, Statewide, All Classes, 2015 Vintage, Solar PV



3.4.2.6 Ratepayer Impacts

Impacts to non-participating ratepayers vary between scenario assumptions and customer classes. It is important to note that the NEM program does create a net cost in the residential class across all scenarios.

Figure 48: Ratepayer Impact Measure Benefit-Cost Ratio by Scenario and Customer Class, Statewide, 2015 Vintage, Solar PV



Overall, the bill impacts of NEM net costs are relatively modest given the policy benefits. The table below shows the estimated residential customer monthly bill impacts for 500 MW of solar PV by scenario. This analysis assumes that any avoided revenues attributable to residential NEM systems are fully collected within the residential customer class.

Figure 49: Residential Monthly Bill Impact, 500 MW of Statewide Solar PV, 2015 Vintage

Lower NEM Value	Untargeted NEM	Targeted NEM	Higher NEM Value
+$0.35	+$0.27	+$0.20	+$0.15

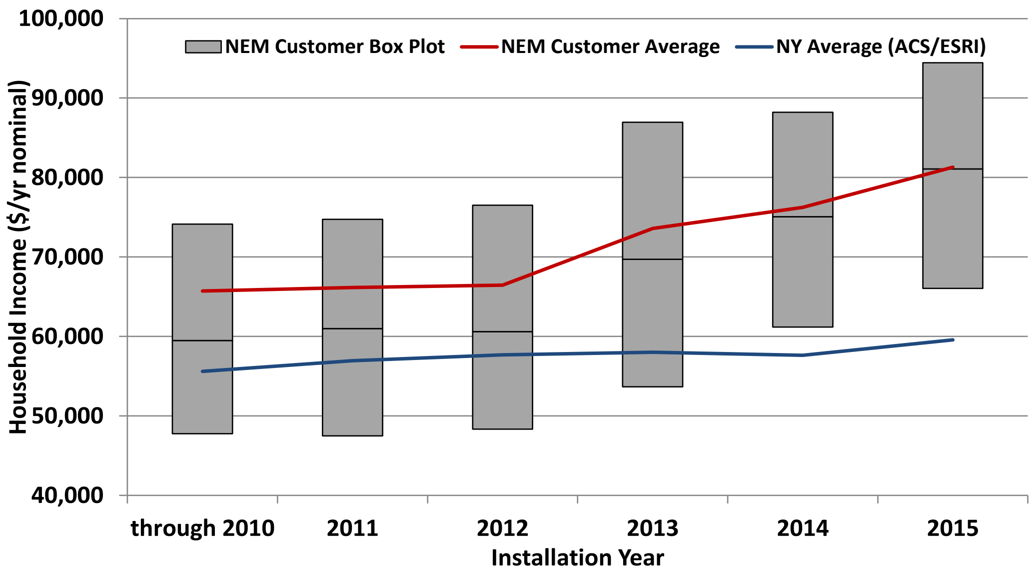
3.5 Residential NEM Income Analysis Results

We find that residential NEM customers live in census tracts with a median household income that has risen from an average of $65,704 in 2010 to $80,674 in 2015 (nominal $). In comparison, New York's median household rose from $55,603 to $59,568 during the same period. The average household income of customers installing NEM systems was 15-35% higher over this period than the median New York State household income. The relative gap rose from a low of 15% in 2012 to 35% in 2015 in large part because of the increase in NEM adoptions by customers on Long Island.

We can conclude that NEM customers live in census tracts with slightly more expensive houses, a slightly older population, a younger housing infrastructure, a higher fraction of owner-occupied housing, and in much denser areas than the State's overall average.

It is expected that New York's new community distributed generation program should help address the disproportionate participation of home-owners and single-family homes in the NEM program which should make solar more accessible to more New Yorkers[72].

Figure 50. Evolution of Household Income of NEM Customers Compared to NY Average Median Income



[72] http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={76520435-25ED-4B84-8477-6433CE88DA86}

Figure 51. Dotted Line Represents NEM Customer Average Median Income without Long Island Customers

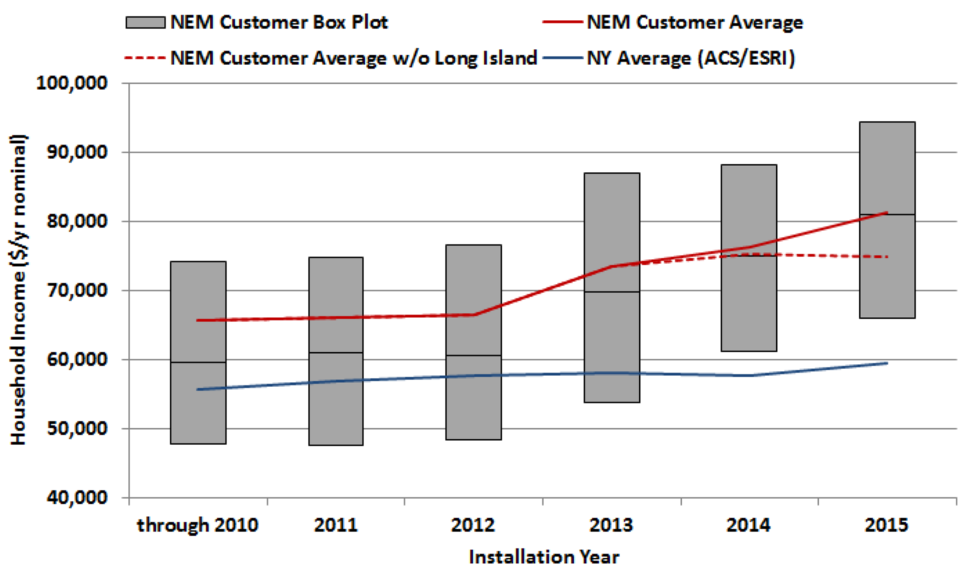
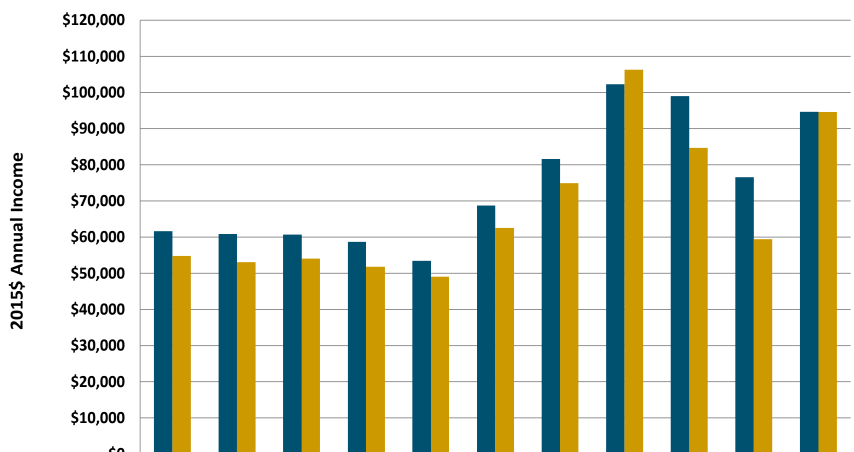


Figure 52: Household Income by NYISO Zone



	A	B	C	D	E	F	G	H	I	J	K
Average NEM Customer Household Income (ESRI 2015)	61,640	60,865	60,703	58,672	53,441	68,744	81,617	102,263	98,996	76,549	94,645
Average Non-NEM Customer Household Income (estimate, ESRI 2015)	54,801	53,059	54,058	51,794	49,041	62,526	74,943	106,307	84,668	59,441	94,626

Figure 53. Cumulative Residential Solar PV Installations in 2015 by NYISO Zone

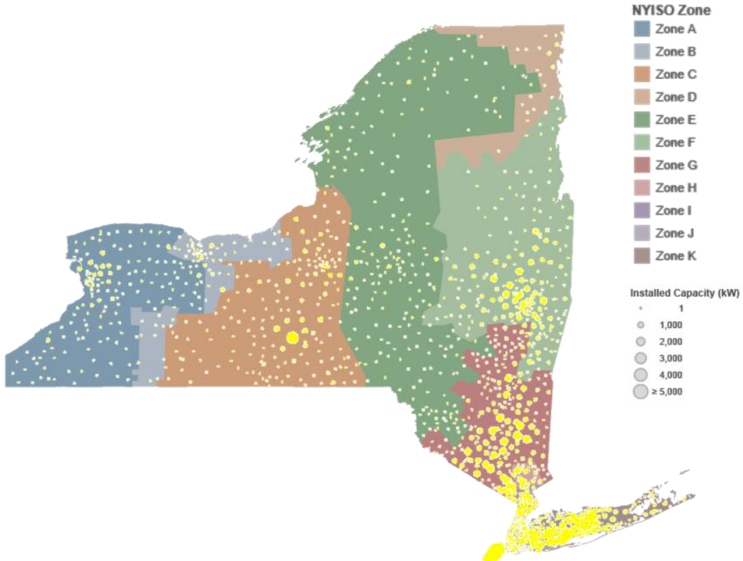


Figure 54: Heat Map of Income Distribution of Residential Solar PV Adopters

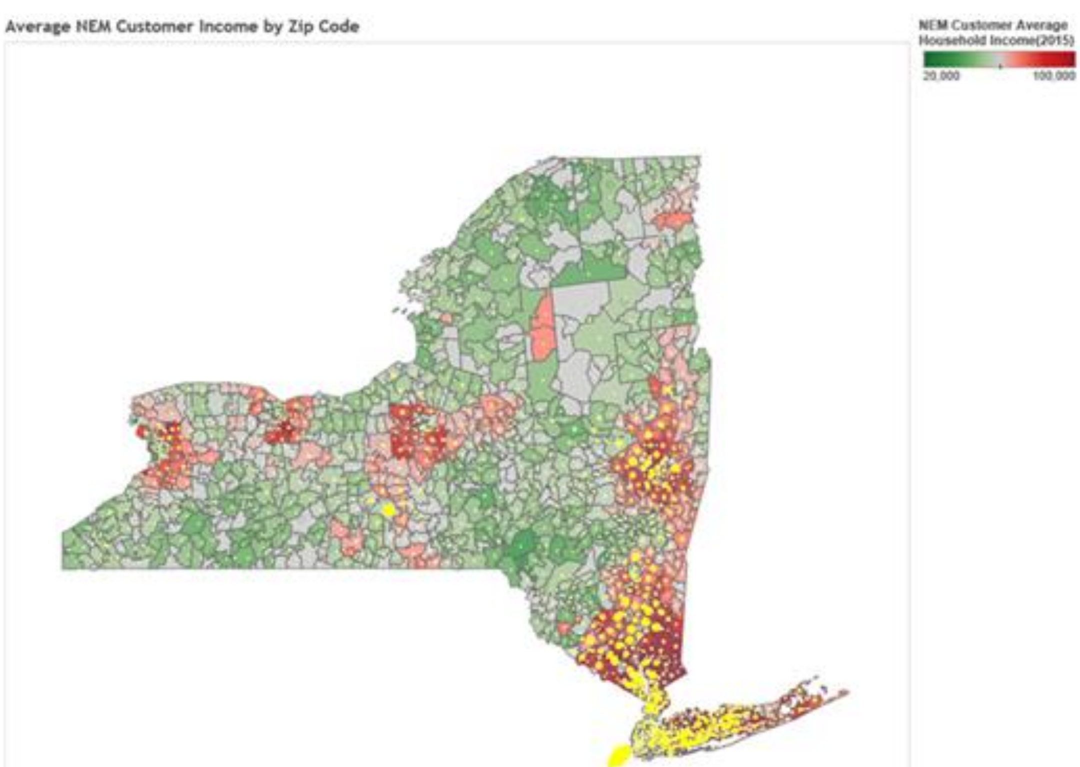


Figure 55: Residential NEM Customer Demographic Information

Based on ESRI Updated Demographic Data (2015).	NY State	Residential NEM Customers Avg.
Median Value of Owner-Occupied Housing Units ($)	297,946	335,923
Median Age	38.6	42.4
Average Year Housing Unit Built	1959	1966
Population Density (#/sq. mile)	419	5,311
Owner Occupied Housing Units / Housing Units	49%	67%

3.6 Public Purpose Charges and Cost of Service Discussion

After installing a NEM system, a customer experiences electric bill savings due to reduced consumption, which means the utility is receiving less revenue from that customer including reduced Public Purpose Charge revenues.

Depending on the underlying rate design of a NEM customer and how much that customer was underpaying or overpaying its utility cost of service before installing a NEM system that customer may end up paying less or more than its cost of service.

3.7 Non-Solar PV NEM Results

This study is focused on solar PV as the predominant technology that is net metered. This is consistent with what has been observed in New York historically, which is a trend that is expected to continue indefinitely in the future under the current NEM policy. Other non-solar technologies are examined in this study, but cost information is less reliable, and resource availability is much more localized (particularly for small hydro systems). The number of adoptions of non-solar NEM generation is expected to remain low compared distributed solar

PV for the foreseeable future. We present below an overview of the cost-effectiveness under the PCT and RIM for these non-solar NEM technologies in the charts below.

Figure 56: Levelized Costs and Benefits, Untargeted NEM Scenario, 2015 Vintage, Statewide, All Classes, Wind

	PCT	RIM
Benefit-Cost Ratio	0.70	0.49

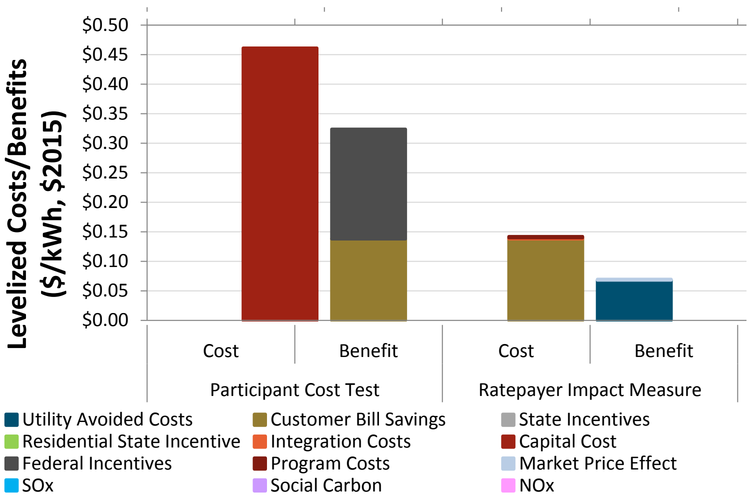


Figure 57: Levelized Costs and Benefits, Untargeted NEM Scenario, 2015 Vintage, Statewide, All Classes, Small Hydro

	PCT	RIM
Benefit-Cost Ratio	2.79	0.52

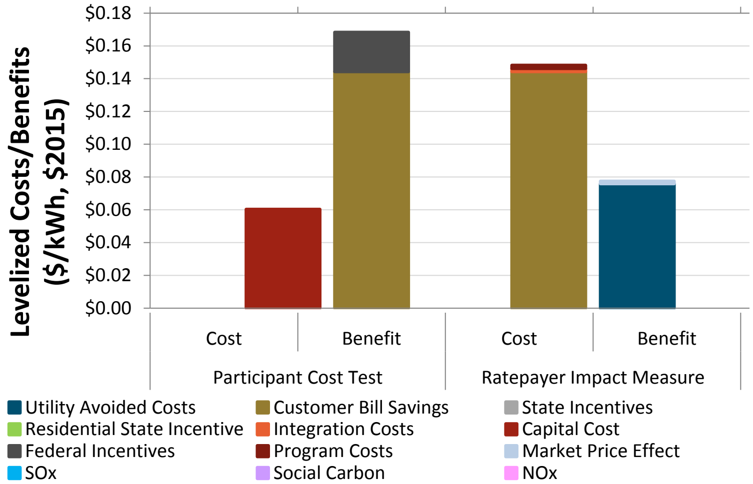


Figure 58: Levelized Costs and Benefits, Untargeted NEM Scenario, 2015 Vintage, Statewide, All Classes, Anaerobic Digester Gas

	PCT	RIM
Benefit-Cost Ratio	0.47	0.53

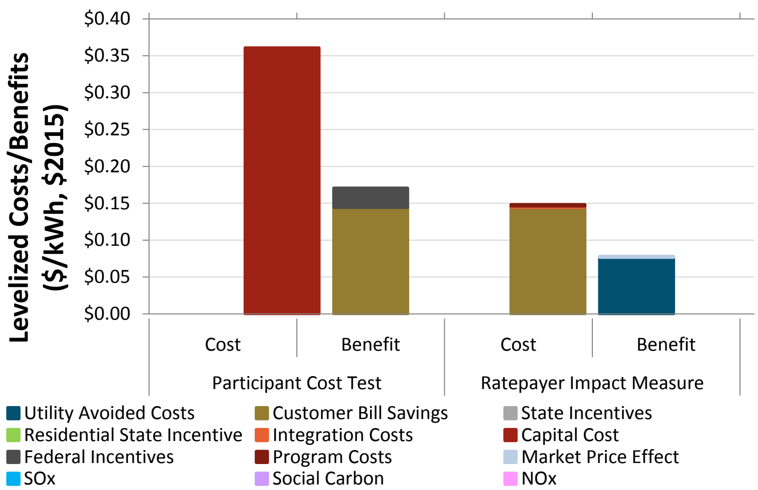
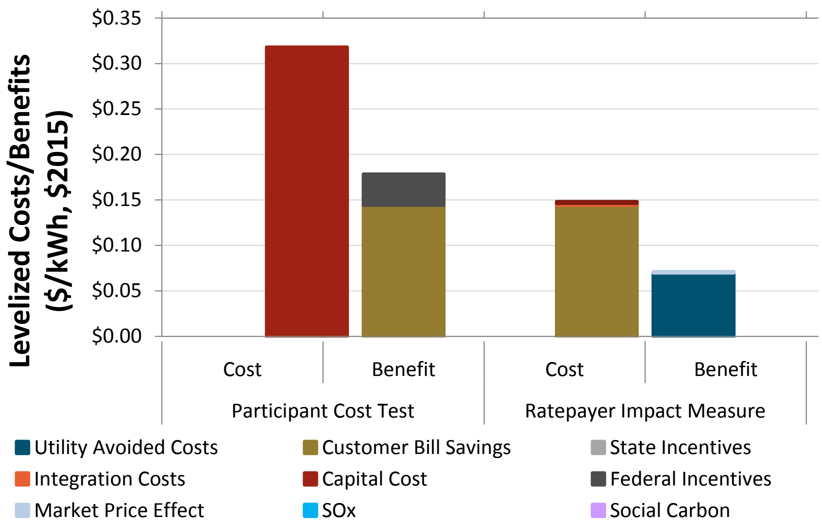


Figure 59: Levelized Costs and Benefits, Untargeted NEM Scenario, 2015 Vintage, Statewide, All Classes, Micro Combined Heat and Power (<10 kW Residential)

	PCT	RIM
Benefit-Cost Ratio	0.56	0.48



4 Conclusions

A range of reasonable input assumptions and results affect the cost-effectiveness of net metered resources. There are also significant differences in results across utilities, the NEM installation vintage,[73] the customer class, and other key inputs that are captured in the four defined scenarios used in the study. However, several key conclusions can be reached, which are as follows:

Conclusion 1: NEM is a key component of the policy to encourage distributed renewable generation in New York, most especially solar PV. However, while NEM offers a simple and understandable tool for consumers, it is an imprecise instrument with no differentiation in pricing for either higher or lower locational values or higher or lower value technology performance (e.g. peak coincident energy production). The costs and benefits of NEM should be monitored given the fast evolution of this market as contemplated in the recent PSC October 15, 2015 Order.[74]

Conclusion 2: After installing a NEM system, a customer experiences electric bill savings due to reduced consumption, which means the utility is receiving less revenue from that customer including reduced revenues for public purpose programs.[75]

[73] This refers to the year the NEM systems are installed. It is expected that NEM system costs will decline over time.

[74] **http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B6D51E352-B4C8-48F9-9354-2B64B14546DC%7D**

[75] These public purpose charges range between $0.007 and $0.009 per kWh (or about $4 to $5 per month for the typical New York residential customer) and exist, largely, to reduce the pollution caused by electricity consumption and generation.

These charges are collected on a per kWh basis since these program costs and benefits are caused by kWh consumption and production. NEM customers who now consume less kWh compared to non-NEM customers therefore lower their payment on these charges on a kWh per kWh basis, i.e., every kWh they generate, they avoid paying $0.007 to $0.009 per kWh.

Alternatively every kWh NEM customers generate is one kWh that does not produce the harmful emissions. This prevention of harmful emissions is one of the reasons these programs were created.

Conclusion 3: The results from cost-effectiveness analysis estimate how much non-participating customers may be paying to enable NEM achievements. Direct financial net costs are borne by non-participating ratepayers across most scenarios and most years of the analysis, especially in the residential customer classes. This analysis shows that potential rate impacts in 2015 for non-participants range between $0.0001 and $0.0004 per kWh across the four defined scenarios (aggregated across each utility and customer class). Unless forecasted NEM adoptions increase much more than expected (i.e., based on the current NY-Sun policy goals), the direct financial net costs of the NEM program will remain relatively modest from a statewide perspective, i.e., result in less than an approximately 0.3% annual rate impact in 2015.

Conclusion 4: In some cases the non-financial societal benefits of NEM systems, i.e., GHG mitigation and improved air quality, when added to the financial benefits, may be greater than the direct financial costs of NEM.

Conclusion 5: Depending on the underlying rate design of a NEM customer and their specific consumption pattern, there will be variations around whether an individual customer was underpaying or overpaying its utility cost of service before and after installing a NEM system, which may result in that customer paying less than its cost of service.[76]

Conclusion 6: For NEM systems installed in 2015, there is a net cost to society (financial and non-financial benefits are approximately 5% less than costs) over the lifetime of these systems in the baseline scenario. However, with a reasonable assumption of forecasted capital cost declines and increases in benefits it was found that there is a net benefit to society for NEM systems installed in 2025 over the lifetime of these systems (financial and non-financial benefits are approximately 25% higher than costs). If NEM systems can be targeted to higher value locations on the distribution grid, then there is a net benefit to society for both systems installed in 2015 (financial and non-financial benefits higher than costs by 6%) as well as in 2025 (financial and non-financial benefits higher than costs by 43%).

[76] Rate design for customers varies significantly by utility and by type of customer class. Generally speaking, residential customer retail rates are designed to recover the utility's cost to serve that class based on average usage and consumption, with over 90% of all variable and fixed costs collected volumetrically on a per kWh basis. However, many customers are not average and by definition any below average or above average customer may not pay the actual cost the utility incurs to serve that specific type of customer. These considerations are inherent and accepted in utility ratemaking.

Conclusion 7: Current NEM customers tend to have higher incomes than average statewide customers, although not necessarily higher incomes than households in their immediate geographic regions (e.g. Long Island). Furthermore, NEM customers live in census tracts with slightly more expensive houses, a slightly older population, a younger housing infrastructure, a higher fraction of owner-occupied housing, and in much denser areas than the State's overall average.

It is expected that New York's new community distributed generation program should help address the disproportionate participation of home-owners and single-family homes in the NEM program, which should make solar more accessible to more New Yorkers.

Appendix: The Benefits and Costs of Net Energy Metering in New York

Prepared for: New York State Energy Research and Development Authority and New York State Department of Public Service

December 11, 2015

Energy+Environmental Economics

The Benefits and Costs of Net Energy Metering in New York:

Prepared for: New York State Energy Research and Development Authority and New York State Department of Public Service

December 11, 2015

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Appendix

1.1 Chapter 510 Legislation for Net Metering Study

Final Language in PSL Article 4 §66-n

§66-n. Net metering study. The commission shall conduct a study to analyze the economic and environmental benefits from and the economic cost burden, if any, of the net energy metering program and to analyze the extent to which ratepayers receiving service under the net energy metering program are paying the full cost of services provided to them by combined electric and gas corporations and gas corporations, and the extent to which their customers pay a share of costs of public purpose programs through assessments on their electric and/or gas bills. In analyzing program costs and benefits for the purposes of this study, the commission shall consider all electricity generated by renewable electric generating systems eligible for net metering under sections sixty-six-j and sixty-six-l of this article, including the electricity used onsite to reduce the customer's consumption of electricity that would otherwise be supplied through the electrical grid, as well as electrical output that is being fed back to the electrical grid for which the customer receives credit or net surplus electricity compensation under net energy metering. As it relates to the environmental benefits, the study shall quantify the approximate avoided level of harmful emissions including, but not limited to, information concerning: nitrogen dioxide, sulfur dioxide and carbon dioxide, as well as other air pollutants deemed necessary and appropriate for study by the commission. The study shall also quantify the economic costs and benefits of net energy metering to participants and non-participants and shall further disaggregate the results by utility. The study shall also gather and present data on the income distribution of residential net metering participants that is publicly available and aggregated by zip code and county. In order to assess the economic costs and benefits at various levels of net metering implementation, the study shall be conducted using multiple net energy metering penetration scenarios.

The commission shall publish a report from its findings. The report must be published within three hundred sixty-five days of the effective date of this section. A copy of the report must be furnished to the temporary president of the Senate, the speaker of the Assembly, the chair of the Senate energy and telecommunications committee and the chair of the Assembly energy committee.

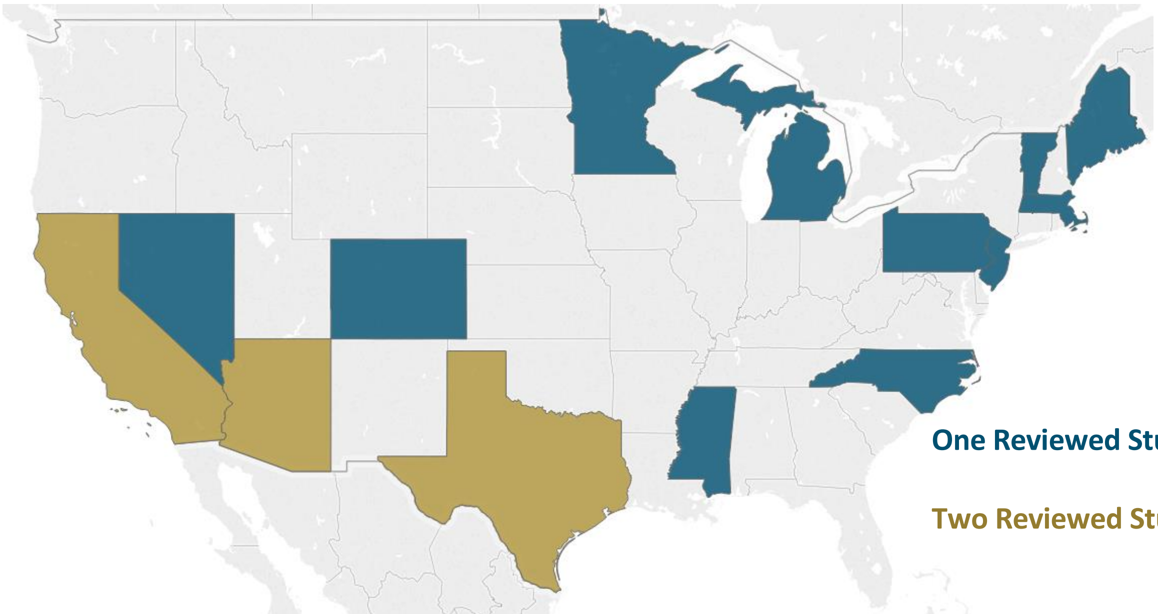
1.2 Literature Review

1.2.1 STUDIES BY REGULATORS, CONSULTANCIES, UTILITIES, AND STAKEHOLDERS

1.2.1.1 Studies Examined

As part of providing context for this analysis on how the benefits and costs of solar resources and net energy metering have been studied in various jurisdictions, E3 reviewed dozens of previous "value of solar" and NEM studies. The review of these studies is meant to provide all readers of this report and other stakeholders with an up-to-date overview on solar valuation policies, mechanisms, and cost/benefit components under consideration to provide context for the framework recommended in this initial analysis. The studies reviewed are shown and listed below:

Figure 1: States Studied in Literature Review[1]



E3 Studies

- Nevada Net Energy Metering Impacts Evaluation[2]
- California Net Energy Metering Ratepayer Impacts Evaluation[3]
- Evaluation of Hawaii's Renewable Energy Policy and Procurement[4]

Other State-Specific Studies and Reports

- Minnesota Value of Solar: Methodology[5]
- Michigan Public Service Commission: Solar Working Group – Staff Report[6] and Value of Grid-Connected Photovoltaics in Michigan[7]

[1] E3 also reviewed a study from Hawaii that is not shown in this map
[2] http://pucweb1.state.nv.us/PDF/AxImages/DOCKETS_2010_THRU_PRESENT/2013-7/39428.pdf
[3] http://www.cpuc.ca.gov/NR/rdonlyres/C311FE8F-C262-45EE-9CD1-020556C41457/0/NEMReportWithAppendices.pdf
[4] http://puc.hawaii.gov/wp-content/uploads/2013/04/HIPUC-Final-Report-January-2014-Revision.pdf
[5] http://mn.gov/commerce/energy/images/MN-VOR-Methodology-FINAL.pdf
[6] https://efile.mpsc.state.mi.us/efile/docs/17301/0073.pdf
[7] http://www.michigan.gov/documents/mpsc/120123_PVvaluation_MI_394661_7.pdf

+ Massachusetts Department of Energy Resources: Analysis of Economic Benefits and costs of Solar Program[8]
+ 2014 Value of Solar at Austin Energy[9]
+ The Value of Distributed Solar Electric Generation to New Jersey and Pennsylvania[10]
+ The Benefits and Costs of Solar Distributed Generation for Arizona Public Service[11] and 2013 Updated Solar PV Value Report prepared for Arizona Public Service[12]
+ The Benefits and Costs of Solar Generation for Electric Ratepayers in North Carolina[13]
+ Evaluating the Benefits and Costs of Net Energy Metering in California[14]
+ Evaluation of Net Metering in Vermont Conducted Pursuant to Act 125 of 2012[15]
+ Net Metering in Mississippi: Costs, Benefits, and Policy Considerations[16]
+ Benefits and costs of Distributed Solar Generation on the Public Service Company of Colorado System[17]
+ The Value of Distributed Solar Electric Generation to San Antonio[18]
+ Maine Distributed Solar Valuation Study[19]

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[8] http://www.mass.gov/eea/docs/doer/rps-aps/solar-consultants-report-final-task-3b-093013.pdf
[9] http://www.cleanpower.com/wp-content/uploads/2014-VOR-at-Austin-Energy-Results-2013-10-21.pdf
[10] http://michigan.gov/documents/mpsc/valuesolarnj_pa_448375_7.pdf
[11] http://www.seia.org/sites/default/files/resources/AZ-Distributed-Generation.pdf
[12] http://www.azenergyfuture.com/getmedia/77708c68-7ca6-45c1-a46f-84382531bae3/2013_updated_solar_pv_value_report.pdf/?ext=.pdf
[13] http://energync.org/assets/files/Benefits%20and%20Costs%20of%20Solar%20Generation%20for%20Ratepayers%20in%20North%20Carolina(2).pdf
[14] http://votesolar.org/wp-content/uploads/2013/01/Crossborder-Energy-CA-Net-Metering-Benefit-cost-Jan-2013-final.pdf
[15] http://publicservice.vermont.gov/sites/psd/files/Topics/Renewable_Energy/Net_Metering/Act%20125%20Study%2020130115%20Final.pdf
[16] http://www.synapse-energy.com/sites/default/files/Net%20Metering%20in%20Mississippi.pdf
[17] http://votesolar.org/wp-content/uploads/2013/12/11M-426E_PSCo_DSG_StudyReport_052313.pdf
[18] http://www.solarsanantonio.org/wp-content/uploads/2013/04/Value-of-Solar-at-San-Antonio-03-13-2013.pdf
[19] http://www.maine.gov/mpuc/electricity/elect_generation/documents/MainePUCVOS-ExecutiveSummary.pdf
http://www.nrcm.org/wp-content/uploads/2015/03/MPUCValueofSolarReport.pdf

"Survey" Type Reports

+ Rocky Mountain Institute Review of Solar PV Benefit & Cost Studies[20]
+ A Regulator's Guidebook: Calculating the Benefits and Costs of Distributed Solar Generation[21]
+ Methods for Analyzing the Benefits and Costs of Distributed Photovoltaic Generation to the U.S. Electric Utility System[22]
+ Ratemaking, Solar Value and Solar Net Energy Metering—A Primer[23]
+ Designing Distributed Generation Tariffs Well[24]

Figure 2: Table of Studies Reviewed

STATE	STUDY	Study Sponsor and/or Audience	State RPS?	State Net Metering?	Highlights
ARIZONA	Crossborder Energy (2013)	Arizona Public Service, as mandated by Arizona Corporation Commission	Yes; 15% by 2025. 30% of that 15% from 2012 on must be DG.	Yes; applied to net excess generation (NEG)	This study is meant to correct what the Commission saw as errors or incomplete evaluation in the earlier SAIC study commissioned by the utility APS. The study should also be viewed in the context of ongoing contentious debates in Arizona around the value of solar and future of NEM.
ARIZONA	APS/SAIC (2013)	Arizona Public Service (AZ's largest utility)	Yes; 15% by 2025. 30% of that 15% from 2012 on must be DG.	Yes; applied to net excess generation (NEG)	This study is meant to update an earlier 2009 study conducted for APS, and finds values they contend are consistent with values in the earlier study. Perhaps the biggest change from the earlier study is increased confidence that distributed generation capacity will not reduce peak distribution loads sufficiently over the next 5-10 years to justify appreciable avoided distribution values. Values reported as annual snapshot present values, not levelized over the lifetime of the system as in most other studies.
CALIFORNIA	E3 (2013)	California Public Utilities Commission (CPUC)	Yes; 33% by 2020, 50% by 2030	Yes; applied to net excess generation (NEG)	Calculates the ratepayer impact measure (RIM) from both an all-generation and export-only perspective. The CPUC has several ongoing proceedings to update the successor tariff to NEM as well as redesign residential retail rates. E3 providing support to the CPUC in this process.

[20] http://michigan.gov/documents/mpsc/solar_pv_benefit_and_cost_studies_448376_7.pdf
[21] http://michigan.gov/documents/mpsc/irecguidebook_448505_7.pdf
[22] http://www.nrel.gov/docs/fy14osti/62447.pdf
[23] https://www.solarelectricpower.org/media/51299/sepa-nem-report-0713-print.pdf
[24] http://www.raponline.org/document/download/id/6898

STATE	STUDY	Study Sponsor and/or Audience	State RPS?	State Net Metering?	Highlights
CALIFORNIA	Crossborder Energy (2013)	The Vote Solar Initiative	Yes; 33% by 2020, 50% by 2030	Yes; applied to net excess generation (NEG)	Mostly uses E3 tools developed for the study listed above, but modifies assumptions in ways that generally increase the value of solar.
COLORADO	Xcel (2013)	Colorado Public Utilities Commission (Mandated by PUC decision C09-1223)	Yes; Investor Owned Utilities 30% by 2020, lower for other utilities.	Yes; applied to net excess generation (NEG)	Xcel Energy has proposed and lobbied for changes to NEM, but in early 2014 the Colorado PUC decided any changes to NEM would be considered in a separate proceeding from the larger ongoing one on the state's renewable energy standard.
HAWAII	E3 (2014)	Hawaii PUC (intended audience) & NARUC (funder)	Yes; 40% for all utilities by 2030	No; NEM changed to customer choice between an avoided cost (close to wholesale price) compensation for DG and a self-supply option with no ability to export as of October 2015[25]	The NEM analysis is part of the report's larger goal to review the cost-effectiveness of Hawaii's path to meeting its 40% RPS. Thus, the study looks at utility-scale resources as well, not just distributed generation. The study finds policies such as a Feed-in-Tariff or utility procurement mechanism would likely be more cost-effective than NEM. Hawaii is currently undertaking significant regulatory reforms to the utility sector, and recently implemented new tariffs for DG remuneration along with new TOU rates and a minimum residential monthly bill of $25.
MAINE	Clean Power Research & Sustainable Energy Advantage (2015)	Maine Public Utilities Commission	Yes; 40% for all utilities by 2017 (10% new since 2005)	Yes; applied to net excess generation (NEG)	Societal benefits account for 50% of first-year value of solar and approximately 60% of long term (25 year) value of solar of $.33/kWh. Study is being used to help guide ongoing NEM reform deliberations as the state's major utility (Central Maine Power) is close to exceeding its 1% of peak load NEM cap.
MASSACHUSETTS	La Capra Associates (2013)	Massachusetts Department of Energy Resources (DOER)	Yes; 15% of new (post-December 31, 1997) sales by 2020, increase by 1% each year thereafter. Mandated target of 1600 MW in-state PV by 2020.	Yes; with three classes (<60kW, 60kW-1MW, 1-2MW) that have slightly different compensation mechanisms under NEM	This study is a benefit-cost analysis of MA's entire solar DG policy as planned, not a generalizable avoided cost calculation. Costs for the whole program compared to base case assumptions are reported, but are not reported on a per-kW or per-kWh levelized basis. No cost tests are conducted. The results of this study are thus difficult to compare to other studies using other more standard methodologies.
MICHIGAN	NREL (2012)	Michigan Public Service Commission	Yes; 10% for all utilities by 2015	Yes; applied to net excess generation (NEG)	For all avoided cost components except energy, this report takes a simple average of four recent studies by Austin Energy (Austin, TX), WE Energies (Milwaukee, WI), Navigant (Madison, WI), and APS (AZ).
MINNESOTA	Clean Power Research (2014)	Minnesota Public Utilities Commission	Yes; Xcel Energy 31.5% by 2020, other IOUs 26.5% by 2025, other utilities 25% by 2025	NEM or VOS (utility discretion; VOS only available to IOU customers)	This study formed the basis of the current optional (utility discretion) value of solar tariff in Minnesota. Social Cost of CO_2 is included in this value.

[25] http://www.utilitydive.com/news/what-comes-after-net-metering-hawaiis-latest-postcard-from-the-future/407753/

STATE	STUDY	Study Sponsor and/or Audience	State RPS?	State Net Metering?	Highlights
MISSISSIPPI	Synapse Energy Economics (2014)	Public Service Commission of Mississippi	No	No. The Mississippi Public Service Commission voted to open docket 2011-AD-2 in order to investigate establishing and implementing net metering and interconnection standards for MS on December 7, 2010.	Find "net metering provides net benefits under almost all of the scenarios and sensitivities analyzed." Assumptions include solar data based on a single location in the state (Meridian) for which PV Watts data was available and an averaging of commercial and residential system values.
NORTH CAROLINA	Crossborder Energy (2013)	North Carolina Utilities (DEC, DEP, DNCP) (audience), North Carolina Sustainable Energy Association (funder)	IOUs 12.5% by 2021, co-ops and Municipal Utilities 10% by 2018	Yes; applied to net excess generation (NEG)	Find the benefits of solar DG exceed the costs by 30% in the case reviewed. This study reviews each of the three major North Carolina IOUs individually.
NEW JERSEY	Clean Power Research (2012)	Mid-Atlantic Solar Energy Industries Association, Pennsylvania Solar Energy Industries Association	Yes; 22.5% of electricity sales by energy year 2021 (June 2020-May 2021)	Yes; applied to net excess generation (NEG)	Find a high value of solar in the areas of PA and NJ examined ($0.25-$0.35/kWh). Include various benefits that are not included in other studies (e.g. Security Enhancement, Economic Development, and Societal Value to future generations).
NEVADA	E3 (2014)	Public Utilities Commission of Nevada	Yes; 25% by 2025	Yes; applied to net excess generation (NEG)	Undertake all five major cost tests (RIM, PCT, PACT, TRC, SCT). Under current rules incentives lead to a cost-shift from NEM to non-NEM customers. Proposed changes to incentives and the implementation of SB 123 will mostly eliminate this cost shift. There is also a relatively large RPS avoidance benefit due to the specific nature of how Nevada's RPS is structured.
PENNSYLVANIA	Clean Power Research (2012)	Mid-Atlantic Solar Energy Industries Association, Pennsylvania Solar Energy Industries Association	Yes; ~18% alternative energy resource by compliance year 2020-2021	Yes; applied to net excess generation (NEG)	Find a high value of solar in the areas of PA and NJ examined ($0.25-$0.35/kWh). Include various benefits that are not explicitly included in other studies (e.g. Security Enhancement, Economic Development, and Societal Value to future generations).
TEXAS (AUSTIN)	Clean Power Research (2014)	Austin Energy	Technically no. But, Texas has a goal set in 1999 of 5880 MW of new renewables by 2015 and 10000 MW (voluntary) by 2025. It has already surpassed the 2025 target. The cities of Austin (35% by 2020) and San Antonio (20% by 2020) have their own separate RPS goals.	There is no statewide net metering policy. Austin Energy had NEM (now a VOST), the city of Brenham has NEM, and customers of Green Mountain Energy (a green electricity retailer) can also get NEM.	Following this and similar work Austin implemented the country's first value of solar tariff (VOST). The VOST is based on fuel value, plant O&M value, generation capacity value, avoided T&D capacity cost, and avoided environmental compliance cost. The VOST methodology as per a recent Austin City Council resolution now includes the value of avoided fuel hedging costs.

STATE	STUDY	Study Sponsor and/or Audience	State RPS?	State Net Metering?	Highlights
TEXAS (SAN ANTONIO)	Clean Power Research (2013)	Solar San Antonio/San Antonio Utility CPS Energy	Technically no. But, Texas has a goal set in 1999 of 5880 MW of new renewables by 2015 and 10000 MW (voluntary) by 2025. It has already surpassed the 2025 target. The cities of Austin (35% by 2020) and San Antonio (20% by 2020) have their own separate RPS goals.	There is no statewide net metering policy. Austin Energy had NEM (now a VOST), the city of Brenham has NEM, and customers of Green Mountain Energy (a green electricity retailer) can also get NEM.	The study finds a potential favorable value of solar. However, CPR was unable to obtain data directly from CPS Energy, and add the caveat that utility data would be needed to make conclusions sufficiently robust. Obtaining this data would allow other factors like the cost of accepting solar onto the grid should also be included.
VERMONT	Vermont PSC (2013)	Vermont Public Service Board (PSB)	Yes; 20% by 2017. Called Sustainably Priced Energy Enterprise Development Goals (SPEED).	Yes; applied to net excess generation (NEG)	This study/review was mandated by Act 125, passed in 2012. The analysis does not find a significant cost shift, and thus does not recommend meaningful changes to NEM.

As seen in the figure below, recent studies come from a variety of perspectives, clients, and stakeholders which have been used in ongoing debates over the “value” of solar and future of NEM. The subsequent results Section highlights how each study’s calculated value of solar resources vary due to the differing assumptions and goals of the studies enumerated above.

1.2.1.2 Results

Figure 3: Examples of Various Benefit-Cost Studies on Net Metering and Solar PV

EXAMPLES OF RECENT NEM VALUE STUDIES FROM STATES, UTILITIES, CONSULTANCIES, AND STAKEHOLDERS

Included	●
Included as a sensitivity	◐
Represented/captured in other values	○

STATE	STUDY	BENEFITS ANALYZED												COSTS ANALYZED				BENEFIT/COST TESTS							
		Avoided Energy (incl. O&M, fuel costs)	Avoided Fuel Hedge	Avoided Capacity (generation and reserve)	Avoided Losses	Avoided or Deferred T&D Investment	Avoided Ancillary Services	Market Price Reduction	Avoided Renewables Procurement	Monetized Environmental	Social Environmental	Security Enhancement/Risk	Societal (incl. economic/jobs)	PV Integration	Program Administration	Bill Savings (Utility Revenue Loss)	Utility/DER Incentives	Total Resource Cost Test (TRC)	Program Administrator/Utility Cost Test (PACT/UCT)	Cost of Service (COS) Analysis	Ratepayer Impact Measure (RIM)	Participant Cost Test (PCT)	Societal Cost Test (SCT)	Revenue Requirement Savings: Cost Ratio	Net Cost Comparison of NEM, FIT, Other
ARIZONA	Crossborder Energy (2013)	●		●	●	●	●	○	●	●		○	○	●		●	◐				●				
ARIZONA	APS/SAIC (2013)	●		●	○	●																			
CALIFORNIA	E3 (2013)	●		●	●	●	●		●	●				●	●	●				●	●				
CALIFORNIA	Crossborder Energy (2013)	●		●	●	●	●		●	●				●	●	●					●				
COLORADO	Xcel (2013)	●	●	●	●	●	○			●				●											
HAWAII	E3 (2014)	●		●	●	◐	●				◐														●
MAINE	Clean Power Research (2015)	●	●	●	○	●	○	●			●			●											
MASSACHUSETTS	La Capra Associates (2013)	●		●	○	●		●	●	●		◐	◐			●	●	●			●				
MICHIGAN	NREL (2012)	●	●	●	●	●	●		○	●															
MINNESOTA	Clean Power Research (2014)	●	○	●	●	●					●														
MISSISSIPPI	Synapse Energy Economics (2014)	●	●	●	●	●				●				●	●	●		●				●		●	
NORTH CAROLINA	Crossborder Energy (2013)	●	●	●	○	●	○	○	●	●	◐	○	○	●		●	●								
NEW JERSEY	Clean Power Research (2012)	●	●	●	●	●		●	○		●	●	●	●											
NEW YORK	E3 (2015) (Based on DPS BCA)	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●		●	●	●	●		
NEVADA	E3 (2014)	●		●	●	●	●		●	●				●	●	●	●	●	●		●	●	●		
PENNSYLVANIA	Clean Power Research (2012)	●	●	●	●	●		●	○		●	●	●	●											
TENNESSEE	TVA (2015)	●		●	○	●				●	◐														
TEXAS (AUSTIN)	Clean Power Research (2014)	●	○	●	●	●			○	●															
TEXAS (SAN ANTONIO)	Clean Power Research (2013)	●	○	●	●	●				●															
VERMONT	Vermont PSC (2013)	●		●	○	●	●	●	●	●	◐				●	●					●				

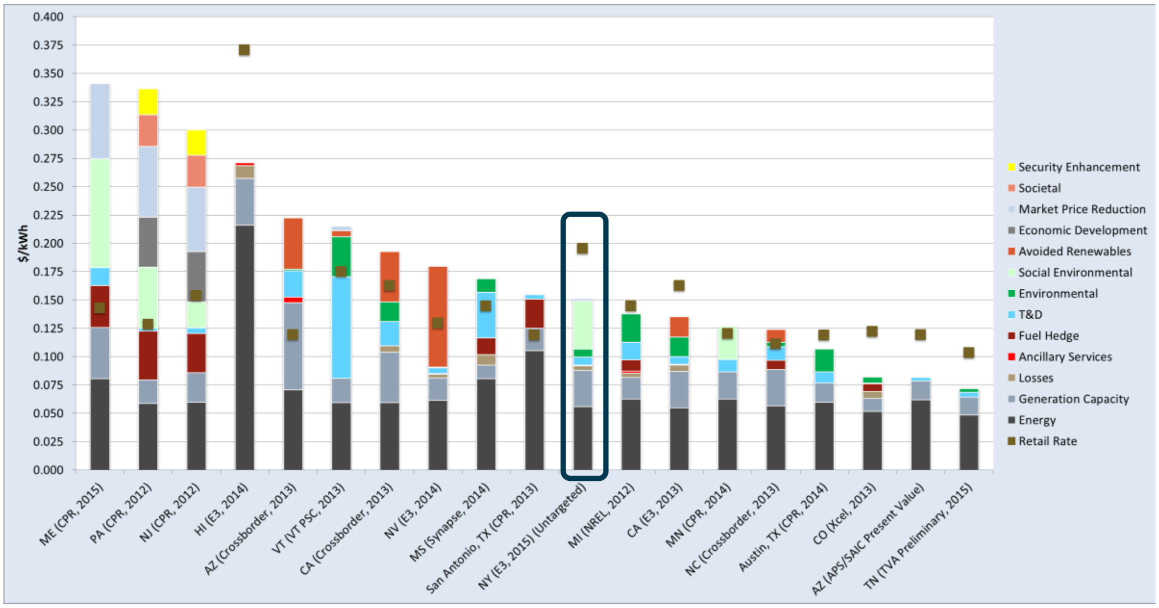
As shown above, there are certain solar PV benefit components that are valued in most or all studies. These commonly valued components are usually “monetized” by utilities explicitly and therefore paid for by ratepayers. These benefit components include energy, system capacity (generation), and transmission and distribution (T&D) investments. The inclusion of these components is generally uncontroversial, although the exact calculation methodology is debated and open to interpretation and differing assumptions. Other monetized benefits include environmental benefits, i.e. SO_x, NO_x, and/or CO_2 compliance costs which also vary from study to study and state to state in calculation methodology. Transmission and distribution losses and ancillary services are also generally included, but can be rolled up with other avoided cost components (often energy). The above are all monetized benefits in the sense that there are explicit dollar market values associated with the prices of energy, capacity, energy lost in transmission, and environmental values such as cost of carbon under the Regional Greenhouse Gas Initiative (RGGI) or California's cap-and-trade system.

"Non-monetized" benefit components are not usually calculated by utilities as "avoided" due to generic generation resources benefits,[26] are included in only some subset of the studies, and are generally more open to interpretation on assumptions about how to quantify benefits for which there is no explicit market value. For some non-monetized benefits one can use economic methods to model the effect of installing distributed solar PV (e.g. as a fuel hedge, or to avoid other RPS procurement). In other cases a price is assigned to an externality value (e.g. for security enhancement or a social cost of carbon).

The figure below quantifies the sum of these benefits of solar PV compared to the average residential retail rate for electricity in the state the study evaluated in 2013. US-wide average residential retail rate was $0.1212/kWh in 2014[27], with rates ranging from Hawaii's $0.3699/kWh to hydro-rich states such as Washington where retail rates were under $0.087/kWh. For reference, New York's average residential retail electricity rate was $0.1884/kWh in 2014 – higher than all of the states reviewed below other than Hawaii (Vermont was the next highest of those reviewed at $0.1715/kWh).

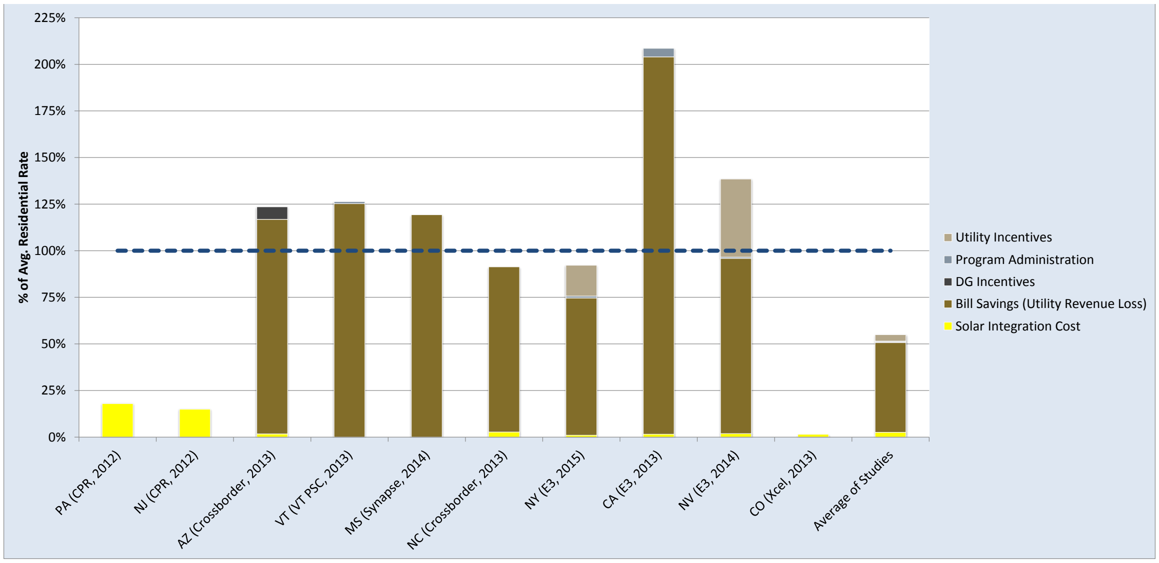
[26] Non-monetized benefits include fuel hedge, effects on the overall wholesale energy markets (Market Price Effect or MPE), avoided future renewable procurement displaced by current renewable purchases, security enhancement, and others.
[27] According to the Energy Information Administration (EIA). More information is available at: **http://www.eia.gov/electricity/monthly/epm_table_grapher.cfm?t=epmt_5_6_a**

Figure 4: Examples of Value of Solar Studies-Benefits Compared to Average Residential Retail Rate for that State as Reported by the Energy Information Administration (EIA)



When examining solar PV costs, the above studies are less detailed and comprehensive than for examining and valuing benefits. Only a handful of studies look either at customer bill savings (i.e. participating customer's bill savings which can also be viewed as lost utility revenues due to on-site generation/consumption plus NEM compensation) or costs associated with installing solar. As the figure below makes clear, these customer bill savings are usually the largest cost from a utility perspective associated with behind-the-meter solar generation under a net metering policy. Other costs that are examined often include a relatively low utility cost associated with integrating distributed solar PV resources to the existing grid (this assumes distributed solar PV penetration/uptake is relatively low). Further, determining customer bill savings is often a complex exercise involving analyzing each individual customer's rates including the applicable NEM tariff and consumption patterns prior to and after the adoption of solar PV. Note the results for California are relatively high due to California's unique residential rate design of highly inclined tiered rates and the particular types/profiles of customers that have installed solar PV in the state.

Figure 5: Examples of Costs Compared to Average Residential Retail Rate as reported by EIA



This literature review proved extremely useful in crafting our recommended methodological framework as we were able to put it in context to provide a reasonable and inclusive list of potential benefit and cost components as well as providing alternative methods to evaluate and compare these components. This review was used to inform which potential benefits and costs should be examined as well as what appropriate proxy values could look like in the New York context.

1.2.1.3 Granular Literature Review Results for Certain Components

Environmental										
STATE	**STUDY**	**Methodology**						**Calculated Value**	**Levelization Duration**	**NOTES**
		Carbon Dioxide	Criteria Air Pollutants	Water	Other Health Benefits	General Environmental Value	Average of Other Studies		in Years	
ARIZONA	Crossborder Energy (2013)		•	•				$0.001/kWh	20	Per MWh of renewable generation value taken from 2012 APS IRP

Environmental										
STATE	STUDY	Methodology						Calculated Value	Levelization Duration	NOTES
		Carbon Dioxide	Criteria Air Pollutants	Water	Other Health Benefits	General Environmental Value	Average of Other Studies		in Years	
CALIFORNIA	Crossborder Energy (2013)	●						$0.017/kWh	20	CO_2 value taken from E3 energy efficiency avoided cost calculator. Assumed to be $30/short ton as per forecast developed by Synapse Consulting.
CALIFORNIA	E3 (2013)	●	●					$0.017/kWh	20	Based on permit price from CARB 2013 auction results and 2011 Market Price Referent. Criteria pollutant emissions included in capital cost of generation.
COLORADO	Xcel (2013)	●						$0.005/kWh	20	CO_2 cost is a volumetric average of PIRA, CERA, and Wood Mackenzie forecasts, and is roughly $15.75/short ton in 2021 escalating at ~7%/year. Forecast of avoided CO_2 emissions is done by ProSym model. Less coal is avoided in later years as coal generation is retired, thus decreasing avoided emissions value per MWh.
MAINE	Clean Power Research (2015)	●	●					$.096/kWh ($0.021 for Social Cost of Carbon, $0.062 for SO_2, and $0.013 for Nox)	25	Societal carbon cost the federal social cost of carbon net of forecast future RGGI allowance prices based on a Synapse report. SO_2 and NO_x are done similarly, with social costs taken from the EPA Regulatory Impact Analysis in the 111(d) Clean Power Plan proposal. Internalized SO_2 compliance costs to net off from this social value are from the EPA allowance clearing price, and NO_x costs are assumed to be 0 because federal rules are not binding in New England.
MASSACHUSETTS	La Capra Associates & Sustainable Energy Advantage (2013)	●	●					N/A (Not reported on a per kWh basis)	25	Changes to CO_2, NO_x, and SO_2 emissions were examined and monetized using allowance prices form the 2013 Avoided Energy Supply Cost study done by the state. This model includes price forecasts based on RGGI permit prices for CO_2.
MICHIGAN	NREL (2012)						●	$0.025/kWh	?	This study values environmental benefits by taking a simple average of the Austin Energy (Hoff et. al. 2006 in Austin, TX), WE Energies (Norris et. al. 2006 in Milwaukee, WI), Navigant (Contreras et. al. 2008 in Madison, WI), and APS (R.W. Beck 2009 in Phoenix, AZ) studies. Note that APS assigns no value to environmental benefits.

Environmental										
STATE	**STUDY**	**Methodology**						**Calculated Value**	**Levelization Duration**	**NOTES**
		Carbon Dioxide	Criteria Air Pollutants	Water	Other Health Benefits	General Environmental Value	Average of Other Studies		in Years	
MINNESOTA	Clean Power Research (2014)	•	•					$0.029/kWh	25	Criteria Air Pollutants valued at 2013 MN PUC-established externality costs. CO_2 emissions valued at federal social cost of carbon (listed as $43/metric ton CO_2 for 2020 in 2007 dollars. CPI adjusted to $54.76/metric ton in 2015 dollars).
MISSISSIPPI	Synapse (2014)	•								Use Synapse mid case for valuation of avoided environmental compliance associated with decreasing carbon emissions. This yields a carbon price beginning in 2020 of $15/ton, increasing to $60/ton by 2040. This decision is justified on the basis of inclusion of carbon price in Mississippi utility IRPs.
NEVADA	E3 (2014)	•	•					$0.0005/kWh	25	Criteria Air Pollutants value taken from NV Energy's 2013 IRP. A CO_2 permit price beginning in 2018 is included in avoided energy costs.
NEW JERSEY	Clean Power Research (2012)	•	•	•	•			$0.023/kWh	30	1 MWh of displaced coal assumed to have environmental cost of $90-250, conventional natural gas $30-60 based on academic studies (Epstein 2011, Devezeaux 2000). All displaced gas assumed to be conventional. Mix of displaced resources depends on state's generation portfolio. CPR uses values near the lower end of these ranges.
NORTH CAROLINA	Crossborder Energy (2013)	•	•					$0.013/kWh	15	Criteria Air Pollutant values from NC 2012 IRPs. Avoided CO_2 value based on a range from Duke Energy Carolina's IRP Base Case Value ($17/ton in 2020, escalating to $44/ton in 2032) to federal Social Cost of Carbon ($35/metric ton in 2012 in 2007$ with 2.1% plus inflation escalation).
PENNSYLVANIA	Clean Power Research (2012)	•	•	•	•			$0.054/kWh	30	1 MWh of displaced coal assumed to have environmental cost of $90-250, conventional natural gas $30-60. All displaced gas assumed to be conventional. Mix of displaced resources depends on state's generation portfolio. CPR uses values near the lower end of these ranges.
TEXAS (AUSTIN)	Clean Power Research (2013)					•		$0.020/kWh	25	This value is assumed to be $.02/kWh as a "conservative" estimate based on current price premiums for "Green-e Renewable" certified electricity Austin Energy customers can opt to purchase. (i.e. it is approximately the incremental cost of opting to purchase certified renewable electricity).

Environmental										
STATE	STUDY	Methodology						Calculated Value	Levelization Duration	NOTES
		Carbon Dioxide	Criteria Air Pollutants	Water	Other Health Benefits	General Environmental Value	Average of Other Studies		in Years	
VERMONT	Vermont PSC (2013)	•						$0.035/kWh	20	CO_2 mitigation value assumed to be $80/metric ton in accordance with value adopted by VT Public Service Board for use in energy efficiency screening. $2/metric ton subtracted off due to current RGGI permit prices, resulting in a value of $78/metric ton. (All figures in 2011$)

Avoided Renewables									
STATE	STUDY	Methodology					Calculated Value	Levelization Duration	NOTES
		Utility IRP Incremental Renewable Cost	Modeled Marginal Renewable Cost	Assumed Incremental Renewable Cost Based on Expertise	REC Cost	SREC Cost		in Years	
ARIZONA	Crossborder (2013)	•					$0.045/kWh	20	Take the cost difference between APS's 2012 IRP Base Case and Enhanced Renewables scenarios. Based on the quantity of additional renewable generation in the Enhanced Renewables case, an incremental cost of renewables is calculated and applied to the quantity of renewables avoided by additional solar DG. This value is assumed to be a proxy for inclusion of fuel diversity, market price suppression, economic development, and grid security benefits.
CALIFORNIA	Crossborder (2013)		•				$0.044/kWh	20	Use E3 tool but assume social value of renewables and 100% export of DG solar generation to the grid to avoid renewables justify both a higher quantity of avoided renewables per unit energy of DG solar generation and counting 100% of the cost premium of renewables toward avoided RPS costs (see below that E3 subtracted off capacity and energy values of that generation being avoided).
CALIFORNIA	E3 (2013)		•				$0.018/kWh	20	Cost of a marginal renewable resource avoided by incremental DG less the energy and capacity value associated with that resource.

Avoided Renewables									
STATE	STUDY	Methodology					Calculated Value	Levelization Duration	NOTES
		Utility IRP Incremental Renewable Cost	Modeled Marginal Renewable Cost	Assumed Incremental Renewable Cost Based on Expertise	REC Cost	SREC Cost		in Years	
MASSACHUSETTS	La Capra Associates & Sustainable Energy Advantage (2013)				•	•	N/A	25	2013 Avoided Energy Supply Cost study forecast of REC prices used. REC prices after 2030 assumed to be constant in real terms. Class I REC prices are multiplied by SRECs generated to calculate a stream of avoided Class I REC costs.
NEVADA	E3 (2014)		•				$0.089/kWh	20	In Nevada for NEM systems built before 2016, every MWh of generation counts as 2.45 RPS credits. NEM also reduces the RPS compliance obligation by reducing net load (obligation: 25% of all generation by 2025). This means 1 MWh of NEM PV generation in 2015 can be banked until 2020, when it can replace almost 2.7 MWh of utility-scale PV generation
NORTH CAROLINA	Crossborder (2013)				•		$0.011/kWh	15	Unbundled REC cost data for NC is not public, so REC prices are estimated based on available REC data from municipal utility purchases, reported utility incremental costs for RPS compliance, and green electricity program cost premiums. This value is assumed to be a decent proxy for inclusion of fuel diversity, market price suppression, economic development, and grid security benefits.
VERMONT	Vermont PSC (2013)			•			$0.005/kWh	20	The cost premium associated with procuring renewable generation to meet state mandates (20% by 2017 and 75% by 2032) is assumed to be $5/MWh nominal "based on conversations with the commenters [in] the [Public Service] Department."

Security Enhancement						
STATE	STUDY	Methodology		Calculated Value	Levelization Duration	NOTES
		Avoided Risk Adder	Assume PV reduces high-stress demand power outages		in Years	
MISSISSIPPI	Synapse (2014)	•		$0.015/kWh	25	DG reduces ratepayers' overall risk by reducing transmission, distribution, fuel, and other cost risks. It also increases competition in the utility sector by inviting the participation of private-sector solar development. For these reasons, Synapse justifies adding a 10% avoided risk adder to their previously calculated avoided cost value for solar. Though included as a security enhancement benefit, this value can also be seen as an effort to approximate general avoided hedging costs.
NEW JERSEY	Clean Power Research (2012)		•	$0.022/kWh	30	Power outages estimated to cost US economy $100 billon/year. 5% of these outages assumed to be high-stress demand avoidable with PV penetration of 15%. Then calculate values of this $5 billion save on a per kWh basis and apply to relevant state's generation.
PENNSYLVANIA	Clean Power Research (2012)		•	$0.023/kWh	30	Power outages estimated to cost US economy $100 billon/year. 5% of these outages assumed to be high-stress demand avoidable with PV penetration of 15%. Then calculate values of this $5 billion save on a per kWh basis and apply to relevant state's generation.

Economic Development (Societal)					
STATE	STUDY	Methodology	Calculated Value	Levelization Duration	NOTES
		Increased tax revenue from net job creation		in Years	
NEW JERSEY	Clean Power Research (2012)	•	$0.045/kWh	30	PV compared to CCGT with assumptions about installed capital costs, percent of costs traceable to local jobs, capacity factor, life span (both 30 years), job value, indirect job multiplier, and tax rates driving the final result

Economic Development (Societal)					
STATE	STUDY	Methodology	Calculated Value	Levelization Duration	NOTES
		Increased tax revenue from net job creation		in Years	
PENNSYLVANIA	Clean Power Research (2012)	•	$0.044/kWh	30	PV compared to CCGT with assumptions about installed capital costs, percent of costs traceable to local jobs, capacity factor, life span (both 30 years), job value, and tax rates driving the final result

Societal (not Economic Development)					
STATE	STUDY	Methodology	Calculated Value	Levelization Duration	NOTES
		Assume longer lifetime for solar PV		in Years	
NEW JERSEY	Clean Power Research (2012)	•	$0.028/kWh	40	The extra 10 years of PV life are added as a proxy for valuing the "well-accepted argument that solar energy is a good investment for our children and grandchildren's well-being." Reducing the discount rate to societal levels of 2% or less is suggested as an alternative methodology.
PENNSYLVANIA	Clean Power Research (2012)	•	$0.028/kWh	40	The extra 10 years of PV life are added as a proxy for valuing the "well-accepted argument that solar energy is a good investment for our children and grandchildren's well-being." Reducing the discount rate to societal levels of 2% or less is suggested as an alternative methodology.

Market Price Effect					
STATE	**STUDY**	**Methodology**	**Calculated Value**	**Levelization Duration**	**NOTES**
		Reduced Market Clearing Price due to Load Reduction		in Years	
MAINE	Clean Power Research (2015)	•	$0.066	25	Use Demand Reduction Induced Price Effects (DRIPE) methodology described in 2013 Avoided Energy supply Costs in New England (AESC) study for the state of Maine to estimate reduction in market clearing price for energy and capacity and thus savings associated with distributed solar installation
MASSACHUSETTS	La Capra Associates & Sustainable Energy Advantage (2013)	•	N/A	25	AESC calculates demand-reduction-induced-price-effects (DRIPE). Based on gross DRIPE impact of the solar to be deployed, a difference is calculated between wholesale electricity prices in the BAU case without solar and the prices reflecting a solar program build-out.
NEW JERSEY	Clean Power Research (2012)	•	$0.057/kWh	30	Use LMPs to calculate price suppression benefit as a function of load reduced. Obtain time-series PV output for the relevant area to determine PV load reduction. Multiply PV output by price suppression benefit to calculate benefit.
PENNSYLVANIA	Clean Power Research (2012)	•	$0.062/kWh	30	Use LMPs to calculate price suppression benefit as a function of load reduced. Obtain time-series PV output for the relevant area to determine PV load reduction. Multiply PV output by price suppression benefit to calculate benefit.
VERMONT	Vermont PSC (2013)	•	$0.004/kWh	20	In the AESC Study Market Price Reduction is a percent of (avoided energy + avoided capacity) that declines as a function of load. The AESC study was meant to apply this value to energy efficiency, VT PSC acknowledges applying the same value to solar PV or wind "is very much approximate."

Fuel Hedge						
STATE	STUDY	Methodology		Calculated Value	Levelization Duration	NOTES
		Guarantee of Sufficient Money, Natural Gas Futures	Natural Gas Futures		in Years	
COLORADO	Xcel (2013)		•	$0.007/kWh	20	Use NYMEX for gas futures
MAINE	Clean Power Research (2015)	•		$0.037/kWh	25	Delta between risk free investment (U.S. government securities) and natural gas futures represents the incremental cost of risk associated with purchasing gas futures. This risk is assumed to be avoidable for any quantity of gas generation avoided by distributed PV.
NEW JERSEY	Clean Power Research (2012)	•		$0.035/kWh	30	Delta between risk free investment (U.S. government securities) and natural gas futures represents the incremental cost of risk associated with purchasing gas futures. This risk is assumed to be avoidable for any quantity of gas generation avoided by distributed PV.
PENNSYLVANIA	Clean Power Research (2012)	•		$0.043/kWh	30	Delta between risk free investment (U.S. government securities) and natural gas futures represents the incremental cost of risk associated with purchasing gas futures. This risk is assumed to be avoidable for any quantity of gas generation avoided by distributed PV.
TEXAS (Austin)	City of Austin Resolution (August 2014)	•		N/A	25	The City of Austin changed the methodology that Austin Energy will use in setting their Residential Solar Tariff to include an explicit fuel hedge component in their energy cost calculations. This will equal the following: the sum of the annual average of upfront historical fuel hedging premium costs over the previous 5 years (not the settlement results), plus annual average projected natural gas costs over 25 years. Projected natural gas costs shall be the 25-year projected average of future natural gas prices using available public market data (e.g. NYMEX) for the first 10 years and continued average percent per-year growth or decline (i.e. exponential best fit) for years 11 to 25.
TEXAS (SAN ANTONIO)	Clean Power Research (2013)	•		$0.026/kWh	30	Delta between risk free investment (U.S. government securities) and natural gas futures represents the incremental cost of risk associated with purchasing gas futures. This risk is assumed to be avoidable for any quantity of gas generation avoided by distributed PV.

1.3 Technology Simulations & Inputs

1.3.1 SOLAR PV

Many benefits and costs of solar PV systems depend on the hourly generation profiles of these systems. Since actual hourly output data was not available, E3 simulated solar profiles and calibrated the output to data provided by NYSERDA that has cost, size, and locational information on solar PV systems installed in New York from 2003 to 2015. According to this database as of June 2015, there are approximately 30,000 solar PV systems installed in New York.

Using customer latitude and longitudes in the NY Sun database, each solar PV system was mapped to a 10 km^2 block from the National Energy Renewable Laboratory's (NREL) Solar Prospector[28] database and corresponding hourly solar insolation data. E3 then converted the hourly insolation data to energy output using industry standard equations available in NREL's System Advisor Model (SAM) software[29]. Several input assumptions were modified to calibrate the average simulated capacity factor[30] to 13.3% (AC) as estimated in the NYSERDA database. The table below lists key assumptions used in the simulation process.

Figure 6: Solar Simulation Assumptions

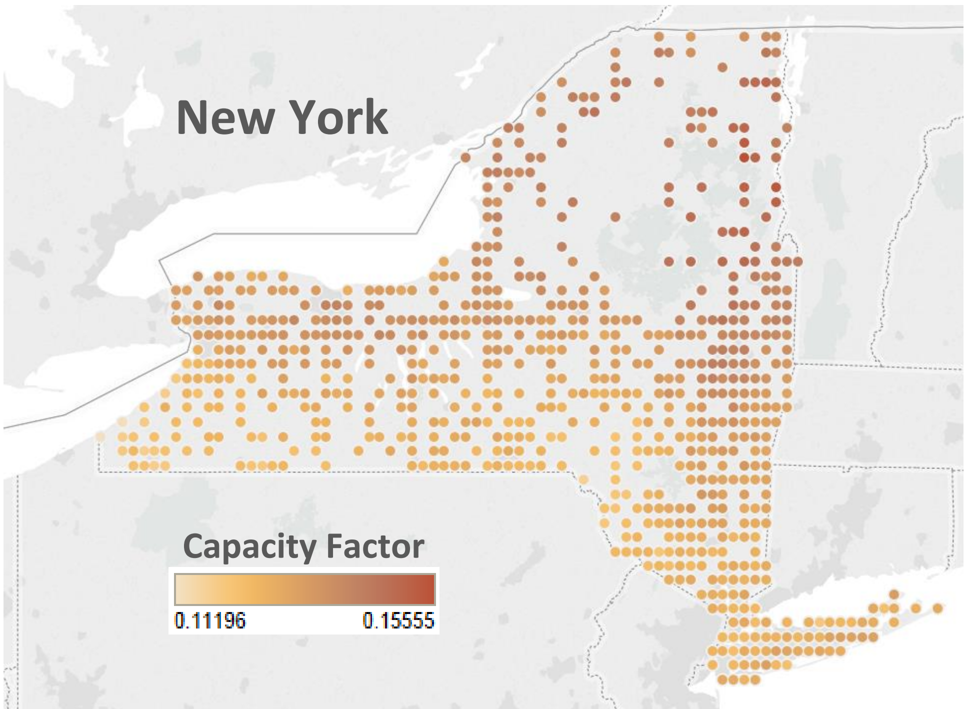
Assumption	
Tilt	Set to latitude of each system
Non-inverter derate	.93
Inverter derate	.95
DC/AC oversizing	1.1/1

The locations for all simulated solar profiles are shown in the figure below along with shading to represent the geographic distribution of capacity factors. Darker circles represent higher

[28] **http://maps.nrel.gov/prospector**
[29] https://sam.nrel.gov/
[30] Capacity factor is defined as the total amount of energy produced by a power plant over a given period of time relative to the amount of energy that would have been produced if the power plant were operating at its full nameplate capacity throughout the entire time period. In general, the capacity factors of renewable energy systems are limited by availability of solar resources.

capacity factors. These factors were then averaged to create average utility specific profiles for solar PV installations.

Figure 7: Simulated Solar Locations with Capacity Factors



The resulting utility-wide capacity factors are shown in the table below.

Utility	Capacity Factor
NYSEG	13.59%
National Grid	13.26%
RG&E	14.06%
Consolidated Edison	12.99%
CHG&E	13.11%
ORU	13.12%
LIPA	13.27%

Other assumptions about Solar PV technology include the following

Category (units)	Assumption
Depreciation Life (MACRS) (years)	5
Fixed O&M ($/kW-yr.)	$15.00
Variable O&M ($/MWh)	$0
Property Tax (%)	0%
ITC[31] Level before 2017	30%
ITC Level after 2017	10%
Residential System Size (kW)	4
Commercial System Size (kW)	75
Industrial System Size (kW)	1,000

1.3.2 WIND

Small Wind 8760 generation shapes and capacity factors vary by utility. The resulting capacity factors are listed below, with the methodology subsequently explained. These were chosen as representative given how site specific wind generation can be and these selections may or may not correspond to actual net metered wind installations. Also not all cities may match with service territories as the goal was to provide a range of potential wind profiles and capacity factors that can differ significantly within a service territory so more representative shapes and profiles were chosen.

Utility	Wind Speed Locations used to simulate this utility	Capacity Factor
Central Hudson	Ulster, Poughkeepsie, Newburgh	12.82%
Consolidated Edison	New York City, Scarsdale	10.34%
Niagara Mohawk (National Grid)	Lake Placid, Buffalo, Corning, Nyack	15.00%
NYSEG	Alfred, Buffalo, Albany, Corning	16.74%

[31] The ITC is the investment tax credit which is the federal tax incentive for qualifying renewable facilities that provides a tax credit for federal taxes which is currently 30% of the facilities qualifying costs. For more detail see: http://programs.dsireusa.org/system/program/detail/658

Orange & Rockland	Monroe	13.08%
Rochester Gas & Electric	Rochester, Alfred, Corning	16.39%
Long Island Power Authority	Sag Harbor, Syosset	14.31%

Methodological steps for obtaining these values are as follows:

1. Obtain 8760 hourly wind speeds for large wind turbines (80m hub height) from NREL System Advisor Model (SAM) for a variety of locations in the state of New York that will be used to represent utilities.[32]

2. Convert these wind speeds to an equivalent hourly wind speed at a 10m (small wind) hub height using the 1/7 power law for wind speeds.

3. Convert 10m hub height wind speeds to an expected hourly power output. To do this E3 used a representative small wind power curve from the Bergey 12.5 kW wind turbine.[33]

4. Create utility values by taking a simple average of geographic locations assigned to that utility; the locations assigned to each utility are shown in the table above.

5. This yields an 8760 power output for each utility. Normalizing these shapes against the rated max output of the representative turbine (12.5kW) yields an 8760 power output by utility as a fraction of the max rated power output. These are the shapes that are then used in E3's model.

The resulting capacity factors are shown in the table above. Of course, wind generation varies hourly and lacks the diurnal pattern of solar, so hourly generation varies between utility depending on the resulting shape as well.

[32] As shown in the above table, these locations include Scarsdale, Buffalo, Nyack, Corning, Alfred, Sag Harbor, Ulster, Poughkeepsie, Newburgh, Monroe, Syosset, Lake Placid, and New York City

[33] See **http://bergey.com/documents/2012/05/excel-10-swcc-summary-report.pdf** and **http://www.wind-power-program.com/** for further information

E3 recognizes that customers who choose to install small wind systems might well install better wind resources than the utility "average" wind resource these shapes represent (i.e., to make wind more economic). However, given little historical data on small wind installations, we determined there was no justifiable methodology for increasing capacity factors above the values shown for our base case scenario.

Other assumptions for wind systems are listed below:

Category (units)	Assumption
MACRS (years)	5
Fixed O&M ($/kW-yr.)	$30.00
Variable O&M ($/MWh)	$0
Property Tax (%)	0%
ITC Level before 2017	30%
ITC Level after 2017	10%
Residential System Size (kW)	5
Commercial System Size (kW)	20
Industrial System Size (kW)	100

1.3.3 SMALL HYDRO

Small Hydro is assumed to have a capacity factor of 89.65%. This shape is based on NY average hydro generation (excluding very large facilities such as Robert Moses and Niagara Falls) from EIA-923 data. We use EIA-923 data from 2001, 2005, 2010, 2011, 2012, and 2013, averaging monthly generation from all hydro facilities excluding the aforementioned large facilities. These monthly generation numbers are then scaled to percentages of the max monthly generation (March), with the following results:

Month	Percent of Max Hydro Generation
January	95.84%
February	85.87%
March	100.00%

April	96.47%
May	93.53%
June	89.80%
July	88.10%
August	79.04%
September	74.13%
October	82.54%
November	92.28%
December	97.67%

These scalars are then averaged to get the monthly hydro capacity factor i.e., the assumption is that the month of highest generation is the maximum output for hydro generation. The further assumption is that these monthly generation totals will approximate river flow for a micro hydro turbine that might be installed by a residential or small commercial customer, such that their generation (based on river flow) would follow the same monthly pattern as that of small hydro generators included in the EIA-923 dataset. Note that generators in EIA-923, while small compared to Niagara, are significantly larger than residential micro hydro installations. Actual output will likely vary by specific installation, but data is not available to model at that level of granularity for the purposes of this study.

Other assumptions for small hydro are listed below:

Category (units)	Assumption
MACRS (years)	5
Fixed O&M ($/kW-yr.)	$30.00
Variable O&M ($/MWh)	$0
Property Tax (%)	0%
ITC Level before 2017	30%
ITC Level after 2017	10%
Residential System Size (kW)	100
Commercial System Size (kW)	100
Industrial System Size (kW)	100

1.3.4 COMBINED HEAT AND POWER (CHP)

CHP is assumed to have a capacity factor of 40.18%. This number is developed based on a 2012 NYC weather dataset (excluding 2/29/2012). The CHP customer is assumed to need sufficient heating to run their CHP system (i.e., be able to utilize both the heat and generation from CHP) in nighttime hours where the temperature is below 50 degrees Fahrenheit and daytime hours where the temperature is below 55 degrees Fahrenheit. This condition is met in 40.18% of hours in our dataset, so we take 40.18% as a good approximation of how often a CHP system would be economic to operate in New York. The customer's CHP system is run at full capacity in those 40.18% of hours meeting the criteria, and is assumed to be off in other hours.

We further note this capacity factor number would vary by customer and geography; the number is meant to be representative. Note, only residential CHP is eligible for NEM.

Other CHP assumptions are listed below:

Category (units)	Assumption
Fuel Cost ($/mmBTU)	$12.50
Heat Rate (Btu/kWh)	15,000
MACRS (years)	5
Fixed O&M ($/kW-yr.)	$10.00
Variable O&M ($/MWh)	$40.00
Property Tax (%)	0%
ITC Level before 2017	30%
ITC Level after 2017	10%
Residential System Size (kW)	10
Commercial System Size (kW)	100
Industrial System Size (kW)	100

1.3.5 ANAEROBIC DIGESTER BIOGAS (ADG)

ADG is assumed to have a 90% capacity factor since, unlike CHP, there is no constraint on ADG operation due to onsite heat needs. The generation shape is assumed to be flat, so ADG is assumed to generate at 90% of its rated capacity in all hours. While in practice ADG might operate at 100% in 90% of hours and be down for maintenance in 10% of hours, a flat distribution represents an assumption of even probability for an outage occurring in any given hour.

Other assumptions are listed below. Note that ADG fuel costs are assumed to be double those of CHP, as biogas is more costly than natural gas.

Category (units)	Assumption
Fuel Cost ($/mmBTU)	$25.00
Heat Rate (Btu/kWh)	10,000
MACRS (years)	5
Fixed O&M ($/kW-yr.)	$10.00
Variable O&M ($/MWh)	$40.00
Property Tax (%)	0%
ITC Level before 2017	30%
ITC Level after 2017	10%
Residential System Size (kW)	10
Commercial System Size (kW)	100
Industrial System Size (kW)	100

1.4 Detailed Results Methodology

E3 uses two key metrics to present results: net present value (NPV) and economic levelized $/kWh. The NPV metric is computed via the following steps:

1. Add up all of the benefits and costs for each year (in nominal $).

2. Subtract the costs from the benefits for each year to obtain the annual net benefit (in nominal $).

3. Using the appropriate discount rate, calculate the NPV of the full net benefit stream in 2015 dollars.

    a. This information is also used to provide benefit-cost ratios equal to the NPV of the benefits divided by the NPV of the costs.

Economic levelized $/kWh values are calculated for one cost or benefit component as follows:

1. Add up all of the costs or benefits to be analyzed by year (in nominal $).

2. Using the appropriate **nominal** discount rate, calculate the NPV of cost and benefit stream in 2015 dollars.

3. Using the appropriate **real** discount rate, calculate the NPV of energy generation (kWh).

4. Divide the NPV dollar values for each cost/benefit component by the NPV energy generation values to get $/kWh.

This provides the economic levelization, i.e. constant real, meaning that this value is constant in real terms or grows at the assumed inflation rate (2% in this analysis). We believe this provides the best comparison when examining snapshot years or across different vintages of installations as this constant real value grows at inflation from year 1 so the total NPV of real vs. nominal levelization is constant.

The NPV metric captures the total magnitude of the impact of NEM throughout the lifetimes of the analyzed NEM systems. This metric is largely driven by installed net metered solar PV capacity and generation. It does not indicate how much of the overall benefit (or cost) is driven by program size versus cost-effectiveness of individual systems. As a result, it is difficult to use this metric to understand how the impact of NEM may scale with additional NEM capacity and generation beyond what is being modeled in this analysis. It is however an effective metric for capturing the total magnitude of the impacts as well as the magnitude of the various perspectives, i.e. utilities, ratepayers, etc.

The levelized $/kWh metric normalizes the NPV results for NEM generation. Consequently, this metric offers more insight into comparisons of benefits and costs across NEM perspectives. Unlike the NPV metric, it does not capture the aggregate NEM impacts or indicate the relative magnitudes of total net benefits across perspectives.

1.4.1 DIRECT BENEFITS (AVOIDED COSTS)

The main source of direct or monetized benefits for NEM-eligible systems is avoided costs, i.e. costs that the utility/ratepayers *avoid* having to pay because of NEM generation. In other words, because NEM systems generate electricity, this has a benefit as utilities/ratepayers will have to pay less for electricity and other related costs. E3 used NYISO forecasts, historical market pricing data, utility filings/reports, and our technology simulations to develop annual hourly (8,760 hours) avoided costs for each of the seven utilities modeled for New York from 2015-2049 (35-year forecast) which are then annualized to develop the avoided cost stream for each vintage of installations up to the 25-year assumed lifetime of each installed system. Using hourly avoided costs captures the time varying value to the grid of energy produced during periods of high demand relative to periods of low demand, which can only be examined at this granularity. While a number of assumptions and various interpolations were required, it is believed that using the methodology for each hour over an 8,760 hour/year analytical framework is strongly preferred in order to more accurately reflect the actual costs that can be avoided by the utility, especially due to distributed solar PV generation which obviously peaks during the daytime.

E3 builds up annual avoided costs for the analysis period (2015-2049) by combining several different cost components. Note, avoided transmission capacity costs are not explicitly examined in our analysis. This is due to the fact that the NYISO CARIS zonal energy price forecast as well as the zonal ICAP capacity pricing already captures a significant portion of the transmission capacity value as congestion between the zones.

1.4.1.1 Avoided Energy Costs

General Description	Study Calculation Methodology/Value
Reduction of costs due to reduction in production from the marginal conventional wholesale generating resource associated with the adoption of distributed NEM.	The value of energy for each utility is derived from a forecast based on production simulation modeling per the NYISO's Congestion Assessment and Resource Integration Study (CARIS). This includes generation energy losses and compliance costs for criteria pollutants but does not include any monetized CO_2 emission costs.

New York has a deregulated wholesale electricity market operated by the NYISO. Wholesale energy costs are incurred by utilities on behalf of serving customer loads. We based our avoided energy costs on existing NYISO forecasts which in turn are based on production simulation modeling. Specifically, E3 relied on NYISO's 2015 final Congestion Assessment and Resource Integration Study (CARIS)[34] study with annual energy (Locational Based Marginal Pricing or LBMP), SO_x, NO_x, and CO_2 price projections from 2015-2024 by NYISO transmission zone.[35] E3 further extrapolated these energy price projections (in $ per MWh) past 2024 to the 2049 analysis horizon first based on the compound annual growth rate of the NYISO forecast energy prices from 2024 to 2033 from the final 2014 CARIS results[36]. For the forecast past 2033 we assume energy prices grow at inflation (assumed to be 2%). We also stripped out the NYISO forecast carbon allowance/emission costs in order to determine energy prices without a monetized carbon cost component since carbon costs are examined separately in this analysis; however, monetized criteria pollutant costs (SO_2 and NO_x) are still included.

The CARIS modeling also relies on the NYISO's "Gold Book"[37] assumptions regarding energy efficiency (EE) and solar PV generation and peak load reduction forecasts. According to NYISO

[34] http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_espwg/meeting_materials/2015-07-07/0707115%20ESPWG%202015%20CARIS%20Base%20Case%20%20Final.pdf
[35] http://www.nyiso.com/public/markets_operations/market_data/maps/index.jsp
[36] http://www.nyiso.com/public/webdocs/markets_operations/services/planning/Planning_Studies/Economic_Planning_Studies_(CARIS)/CARIS_Final_Reports/2013_CARIS_Final_Appendices.pdf
[37] http://www.nyiso.com/public/webdocs/markets_operations/services/planning/Documents_and_Resources/Planning_Data_and_Reference_Docs/Data_and_Reference_Docs/2015%20Load%20and%20Capacity%20Data%20Report.pdf

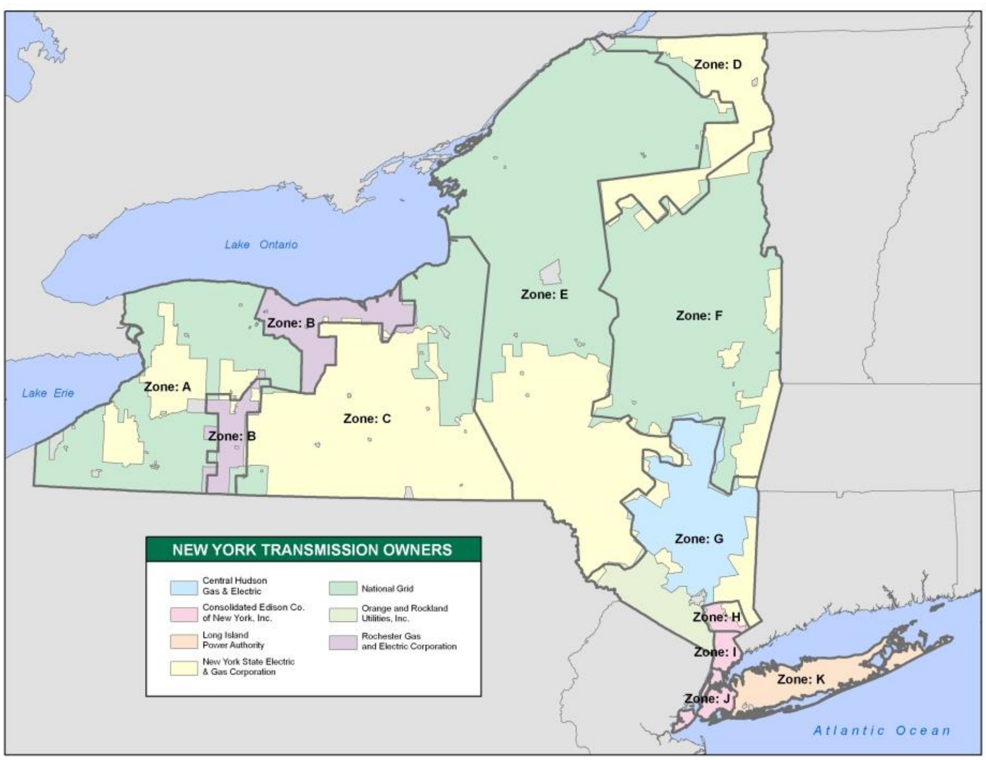
provided data, the CARIS projections assume ~2.7 GW-AC of solar PV by 2025 (~90% of the MW Block Incentive Program target).

E3 then took this strip of annual energy prices (with no monetized carbon costs) from 2015-2049 in conjunction with 8,760 hourly historical pricing ratios to create an 8,760 hourly price stream in $/MWh with annual averages equivalent to the forecasts. These pricing ratios were developed by taking 6-years (2009-2015) hourly day-ahead LBMP[38] data published by NYISO.

The next step involved taking each NYISO zone and mapping/allocating the results to specific New York utility service territories to represent the wholesale marginal energy costs the utility incurs in each territory in serving its residential, commercial, and industrial loads.

Figure 8: NYSERDA Map of NYISO Zones to Utility Service Territories

Based on this map as well as consultation with NYSERDA and other subject matter experts E3



[38]http://www.nyiso.com/public/services/market_training/online_resources/lbmp_online.pdf, http://www.nyiso.com/public/markets_operations/market_data/custom_report/index.jsp

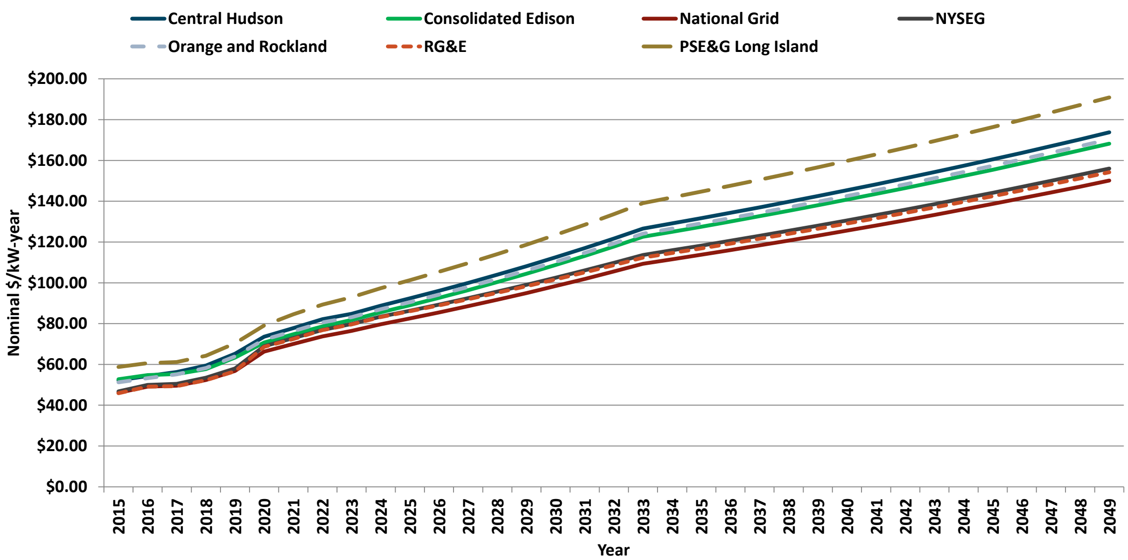
decided upon calculating each utility's avoided energy cost as the weighted average of the NYISO CARIS zonal energy price projections. Then each zone was weighted based on the table below published provided by the NYISO, which maps each utility's average (2009-2014) zonal energy shares.

Figure 9: NYISO 2009-2014 Average Zonal Energy Shares of Utility Loads

NYISO Zone	Central Hudson	ConEd	National Grid	NYSEG	ORU	RG&E	PSEG Long Island	Statewide
A			26.9%	18.8%				7.5%
B			6.5%			100.0%		6.1%
C			19.8%	48.4%				8.8%
D			1.6%	3.7%				1.7%
E			14.2%	12.3%				4.2%
F			31.1%	4.5%				7.1%
G	100.0%			0.8%	100.0%			6.7%
H		2.2%		11.5%				2.0%
I		10.8%						4.4%
J		87.0%						35.3%
K							100.0%	16.2%
TOTAL	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**

E3 then used this table to create the weighting factors to calculate each utility's energy avoided energy cost as a function of the NYISO zonal CARIS energy price projections.

Figure 10: 2015-2049 Energy Price Projections (No Carbon) by Utility for each kW of Solar PV Installed



There are several considerations that are important to note as follows:

+ The NYISO CARIS energy price forecast only reflects approximately 90% of the NY MW Block target installations by 2025, which implies that the CARIS energy prices may be to some extent overstated as solar PV (all else being equal) can depress the spot LBMP prices by reducing the demand, i.e. by reduced customer loads, for electricity which in turn can reduce the clearing price if a more efficient/less expensive generating is setting the marginal price. This effect may be more pronounced if greater than expected solar PV installations occur. This is explored in more detail in the Market Price Effect Section below.
+ In any follow-up analysis it is recommended that hourly energy price forecasts be developed for each utility in a more robust manner matching utility load to zonal load as well examining sensitivities with various levels of solar penetrations and fuel prices in as granular a manner as feasible (both temporally and geographically).

1.4.1.2 Avoided Losses

General Description	Study Calculation Methodology/Value
Reduction of electricity losses from the points of generation to the points of delivery associated with the adoption of distributed NEM.	Utility transmission, and distribution loss factors, i.e. expansion factors, as reported in their respective approved Tariffs. Generation losses are already accounted for in the energy costs.

E3 was provided the following expansion and loss factors from DPS Staff for each utility examined by transmission level (secondary, primary, sub transmission, and transmission). Marginal generation losses are already accounted for in the LBMP pricing in the NYISO CARIS energy price projections. E3 applied the total T&D loss factors for each utility to the avoided energy cost component to determine the avoided losses.

Figure 11: T&D Losses by Utility

Factors of Adjustment

Utility	PSC Tariff Leaf	Secondary	Primary	Subtransmission	Transmission	Total Distribution	Total T&D
Central Hudson	PSC 15 Leaf 104	1.05600	1.03800	1.01850	1.01040	1.04465	1.05600
Con Edison	PSC 10 Leaf 329	1.06300	1.06300	1.06300	1.06300	1.04932	1.06270
Niagara Mohawk	PSC 220 Leaf 216	1.08400	1.06100	1.04700	1.02100	1.06036	1.08400
NYSEG	PSC 120 Leaf 79	1.07280	1.03770	1.01500	1.00000	1.07280	1.07280
Orange & Rockland	PSC 3 Leaf 263	1.07987	1.05641	1.02765	1.02546	1.05167	1.07987
RGE	Footnote[1]	1.06929	1.04910	1.04910	1.04910	1.01833	1.06929
LIPA	Footnote[3]	1.06690	1.03330	1.01570	1.00000	1.06686	1.06686

Loss Factors

Utility	PSC Tariff Leaf	Secondary	Primary	Subtransmission	Transmission	Total Distribution	Total T&D
Central Hudson	Footnote[2]	5.30%	3.66%	1.82%	1.03%	4.27%	5.30%
Con Edison	PSC 10 Leaf 329	5.90%	5.90%	5.90%	5.90%	4.70%	5.90%
Niagara Mohawk	Footnote[2]	7.75%	5.75%	4.49%	2.06%	5.69%	7.75%
NYSEG	Footnote[2]	6.79%	3.63%	1.48%	0.00%	6.79%	6.79%
Orange & Rockland	Footnote[2]	7.40%	5.34%	2.69%	2.48%	4.91%	7.40%
RGE	PSC 19 Leaf 160.9	6.48%	4.68%	4.68%	4.68%	1.80%	6.48%
LIPA	Footnote[3]	6.27%	3.22%	1.55%	0.00%	6.27%	6.27%

Footnote[1] - Calculated from loss factors in the tariff

Footnote[2] - Calculated from FOA in the tariff

Footnote[3] -http://www.lipower.org/pdfs/company/tariff/Stat_EDL.pdf

There are several considerations that are important to note as follows:

- These T&D losses represent losses as presented in each utility's tariff. A potential follow-up analysis could examine marginal loss data during those hours and locations of actual solar PV production, which would capture (among other things) the non-linear effects of losses on the margin potentially being displaced by customer-sited NEM resources.
- Losses could also be examined on a more granular transmission level to match where NEM systems are likely to be installed.

1.4.1.3 Avoided System Capacity Costs

General Description	Study Calculation Methodology/Value
Reduction in the fixed costs of building and maintaining new conventional generation resources associated with the adoption of distributed NEM.	The DPS ICAP model attached to the July 1, 2015 DPS BCA Whitepaper was used to forecast future installed capacity (ICAP) prices appropriate under a load modification approach applicable to each utility. These capacity costs are also adjusted for the appropriate energy T&D losses as well as adjusted by the expected system peak load reduction value realized by each type of NEM technology.

The NYISO procures capacity to meet the peak load needs of the New York Control Area (NYCA). Like the wholesale NY energy market, NYISO has several capacity zones[39] where the utility in each zone is required to procure a certain amount of capacity to serve the peak load needs of its customers through a NYISO administered auction market. This capacity is procured on an "unforced" capacity (UCAP) basis meaning that the installed capacity (ICAP) procured is adjusted for "forced" outages or the percentage of time when a generation unit is unavailable or "forced" to shut down/reduce output due to an unexpected circumstance. Prices are reported both on an UCAP and ICAP basis which are then applied to the applicable UCAP and ICAP MW load serving entity (LSE) obligations. Both calculations yield the same total dollar amount. An ICAP approach was adopted for this analysis which values NEM behind-the-meter generation as a 'load' modifier

[39] http://www.nyiso.com/public/markets_operations/market_data/icap/index.jsp

meaning that the avoided capacity benefit is calculated from the demand side, i.e. NEM generation reduces customer demand which in turn reduces the utility's obligation to purchase capacity as well as the associated reserves to meet the New York Control Area (NYCA) planning reserve margin requirement. The alternative methodology is to value NEM generation from a bulk generator or a UCAP approach.

To this end E3 used relied on the ICAP price forecast from the DPS ICAP model attached as appendix A[40] to the July 1, 2015 benefit-cost analysis (BCA) whitepaper[41]. We relied on the model which uses the NYISO Gold Book to forecast supply and demand under the current parameterized demand-curve model to forecast ICAP prices until 2035. From 2036-2049 we assume constant real prices or no real growth, i.e. prices are only adjusted for inflation after 2035. These prices are then adjusted for the T&D loss percentages described above in order to reflect the distribution level benefits from NEM systems.

Similar to the mapping exercise, performed in determining the appropriate avoided energy costs for each utility examined, we determined each utility's avoided capacity costs (as a weighted average of the capacity zones) as seen in the table below.

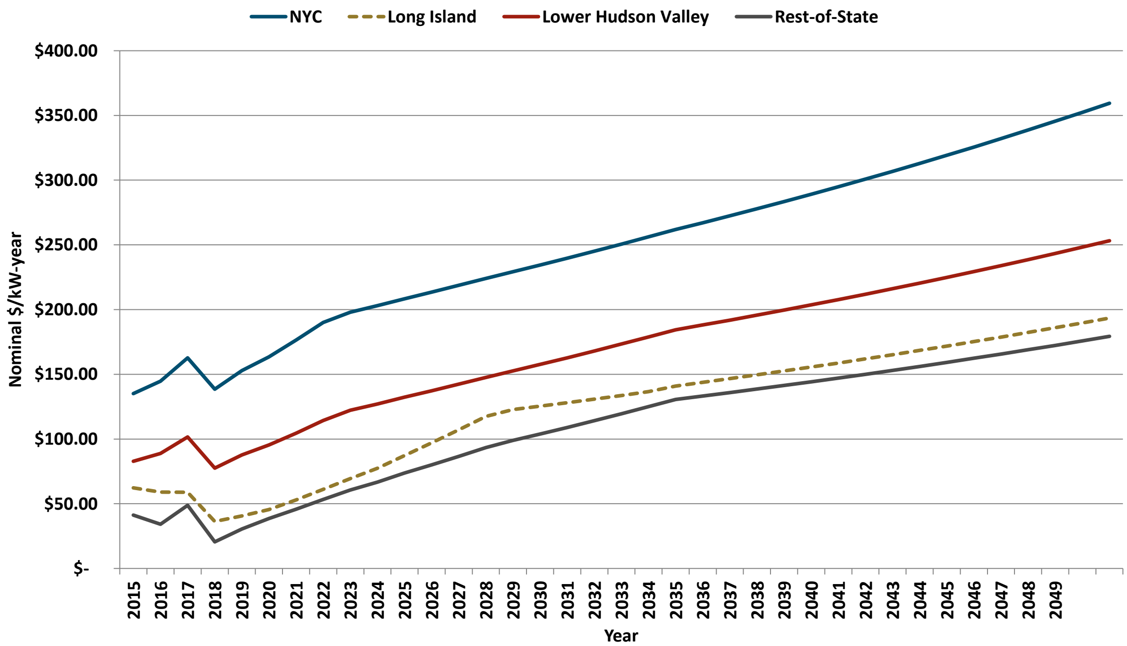
Figure 12: Mapping of NY Utilities to NYISO Zones

Utility	NYISO Capacity Zone
NYSEG	NYCA and Lower Hudson Valley (LHV)
National Grid: (Niagara Mohawk)	NYCA
Rochester Gas & Electric	NYCA
Consolidated Edison	NYC and Lower Hudson Valley (LHV)
Central Hudson Gas and Electric	LHV
Orange and Rockland Utilities	LHV
PSEG Long Island	Long Island

40 http://albapps/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/c12c0a18f55877e785257e6f005d533e/$FILE/REV_BCA_Appendix_A_(ICAP_Forecast_-_June_2015).xlsm

41 http://albapps/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/c12c0a18f55877e785257e6f005d533e/$FILE/Staff_BCA_Whitepaper_Final.pdf

Figure 13: NYISO Zonal ICAP Capacity Forecast ($/kW-year)



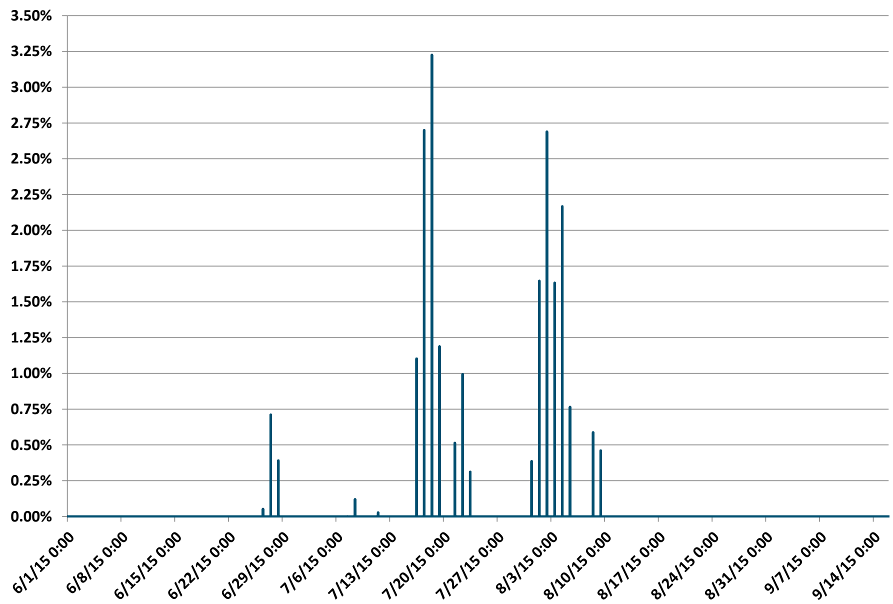
The next step after establishing an ICAP and capacity price forecast by NY capacity zone (adjusting for the appropriate T&D loss savings from distributed NEM systems) and utility is to determine how much of this value applies to a NEM resource. We relied on a peak capacity allocation factor (PCAF) methodology[42] that maps ICAP prices to the top NYCA or system peak hours based on NYCA load data from 2008-2015, which usually but not always occurs between late June and mid-August. This methodology assigns a probability to the top 100[43] system load hours as an approximation for the probability of the peak being in a particular hour in that top 100 hours[44].

[42] http://c.ymcdn.com/sites/www.peakload.org/resource/resmgr/16thspringconf/Lucas-Valuing_Demand_Respons.pdf

[43]Note, this is not how the NYISO assigns capacity value. The NYISO sets a Load Serving Entity's, e.g. utility's, capacity obligation based on a single hour of NYCA system peak,

[44] PCAFs are calculated by taking the top 100 load hours in a year and calculating the total energy (MWh) in those hours. The PCAFs are then determined by dividing the load in each of those 100 hours by the total or sum of the loads of those hours, i.e. if total load of the top 100 hours equals 500 MWh and one hour in that top 100 has a load of 50 MWh; the PCAF for this hour would be 10% (50/500); a similar calculation would be performed for each of those 100 hours so the total hourly percentage will equal 100%. This methodology

Figure 14: PCAF Allocators for ICAP (NYCA System Load)



These PCAFs are then applied against the NEM technology hourly profiles to determine their level of coincidence in order to allocate capacity costs, e.g. if all 100 peak hours occurred during the night and NEM systems only produced during the day there would be zero coincidence and no avoided capacity benefit assigned to these systems because those systems do not provide any peak demand reduction benefits. Conversely if NEM systems were producing 100% of their maximum generation in each of those 100 peak hours then those systems would be assumed to provide an avoided capacity equal to its maximum output or nameplate capacity. The actual coincidence between the NEM generation in the top 100 NYCA hours and the PCAF allocation factors then determines how much avoided capacity cost benefit is being provided or realized by NEM installations. For example, 30% coincidence means that the 'effective' capacity of that installation in terms of realizing any avoided capacity benefit from system peak demand reduction is 30%. This coincidence between solar PV generation for each utility and the system PCAFs can be seen in the chart below.

allows an annual capacity price to be 'spread' or allocated to certain peak hours based on the approximate probability that it will be the peak.

Figure 15: Coincidence of each Utility's Solar PV Profile against System PCAFs

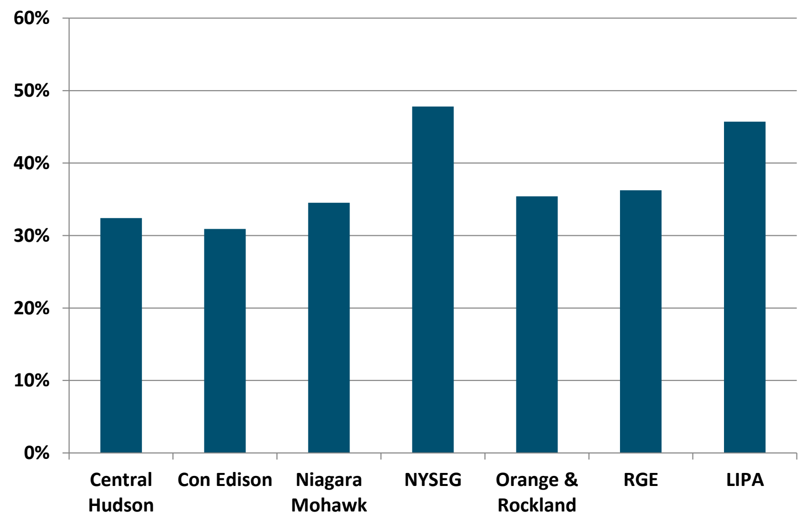
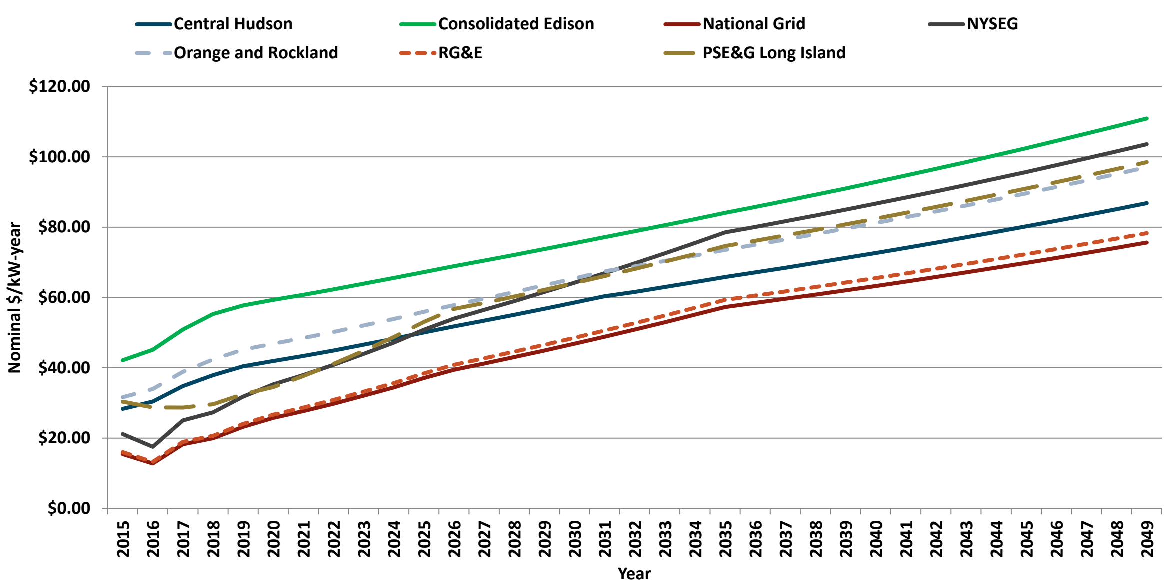


Figure 16: Utility ICAP Capacity Forecast Adjusted for Coincidence/Effective Capacity and T&D Losses for each kW of Solar Installed



There are several considerations that are important to note as follows:

- The mapping of capacity zones to each utility's obligation to procure capacity to serve its load was a simplifying assumption. Actual capacity obligation and cost is a function of each utility's load in each capacity zone as well as a function of the cost of the overall NYCA system capacity requirements. In any follow-up analysis it is recommended that further work on this subject is performed to determine actual capacity prices applicable to a solar PV resource in each utility's service territory.
- Any changes in the forecast load and resource balance such as refueling, uprates, or changes in the planning reserve margin since the July 1, 2015 DPS BCA could potentially change the forecast results by a significant amount.
- Various studies including work by E3[45] show that modeling the effective load carrying capability (ELCC) and capacity contribution of solar PV is not a straightforward matter where solar PV capacity value can diminish over time if system characteristics change such as peak load being shifted to later in the day or evening if enough solar PV is installed. This can be partially mitigated by installing west-facing solar PV to better align solar PV production with the system peak. These are the types of issues that may be suitable for a follow-up analysis.
- E3 has valued the capacity of PV from the perspective of a load modifier. An alternative approach would be to value it as a generator similar to larger generators at the bulk level.

1.4.1.4 Avoided Ancillary Services Costs

General Description	Study Calculation Methodology/Value
Reduction of the costs of services like operating reserves, voltage control, reactive power, and frequency regulation needed for grid stability associated with the adoption of distributed NEM.	A proxy value of 1% of energy costs is assigned. The NYISO procures ancillary services on a fixed rather than load following basis based on a largest single contingency measure, which means the amount of ancillary services procured would not likely decrease in any appreciable way due to the adoption of distributed NEM. There could be some benefit from voltage/reactive power control or power factor correction with newly enabled smart inverter technology.

[45] https://ethree.com/public_projects/recap.php

For avoided ancillary service costs we use a proxy value of 1% of the avoided energy costs. In other jurisdictions ancillary services like operating reserves (reserves needed to account for short-term generation/consumption variation or forecast error) are often procured based on the amount of load, which means that any behind-the-meter generation that reduces a customer's load should theoretically reduce the amount of operating reserves needed (all else being equal). Other jurisdictions like the NYISO have a different operational guideline in place for purchasing operating reserves. Specifically, operating reserves in the NYISO should equal the "operating capability loss caused by the most severe contingency."[46] It was determined that this means at least in the short to medium term the amount of operating reserves procured is relatively fixed and will not change due to the NEM systems installed although there may be future benefits based on 'smart' inverter technology that may allow NEM systems to provide ancillary services benefits which is why a proxy value of 1% of energy costs was chosen.

There are several considerations that are important to note as follows:

+ Given the variability or intermittent nature of behind-the-meter solar PV generation it is unclear whether ancillary services like regulation and voltage control as well as reserve requirements could increase or decrease due to on-site behind-the-meter customer generation associated with NEM.
+ Conversely, there is work being done to install advanced inverters to new solar PV systems that in the future could provide ancillary services benefits to the grid like voltage control, but given current electrical standards this has yet to occur in the meaningful way in the U.S.
+ In any follow-up analysis it is recommended that further study be performed to determine how the NYISO would operate with increasing levels of solar PV penetration to quantify how solar PV can avoid certain ancillary services costs incurred by the utility and/or provide benefits in the future.

[46] http://www.nyiso.com/public/webdocs/markets_operations/market_data/reports_info/nyiso_locational_reserve_reqmts.pdf

1.4.1.5 Avoided Transmission Capacity Costs

General Description	Study Calculation Methodology/Value
Reduction or deferral of costs associated with expanding/replacing/upgrading transmission capacity associated with the adoption of distributed NEM.	The value of transmission capacity is in part captured in the NYISO CARIS zonal production simulation modeling results and is represented as congestion, i.e. energy price differentials, between the NYISO modeled zones. It is also likely captured to some extent in the various zonal NYISO capacity prices, i.e. more transmission and generation constrained capacity zones would likely have a higher zonal capacity price all else being equal.

For avoided or deferred transmission capacity costs E3 chose a proxy value of zero along the lines described in the DPS BCA whitepaper. In that whitepaper it was determined that the value of transmission capacity is most likely captured (to a large extent) in the values of the avoided energy and capacity cost components. The value of avoided or deferred transmission costs will show up as congestion pricing in the NYISO zonal and nodal markets. If there was sufficient transmission and no other operational constraints then energy as well as capacity prices would be lower (all else being equal) than what is being forecast in this analysis. For this analysis it appears that this component is already being accounted for in relatively higher energy and capacity costs in certain NYISO zones and locations, which provides a market based method in determining the value of relieving transmission constraints, i.e. by building transmission capacity. Another way of looking at this is that this is the cost of not having sufficient transmission capacity between zones and locations.

There are several considerations that are important to note as follows:

+ In any follow-up analysis E3 recommends a more in-depth analysis of NYISO's capital expenditure plan for transmission capacity expansion including upgrades/additions to determine on a granular basis which investments can be deferred or even avoided due to NEM eligible resources. Generally speaking, transmission peak demand (which typically drives investment in new transmission capacity) is more aligned with solar PV generation since it relies on a more diversified set of individual solar PV generators.

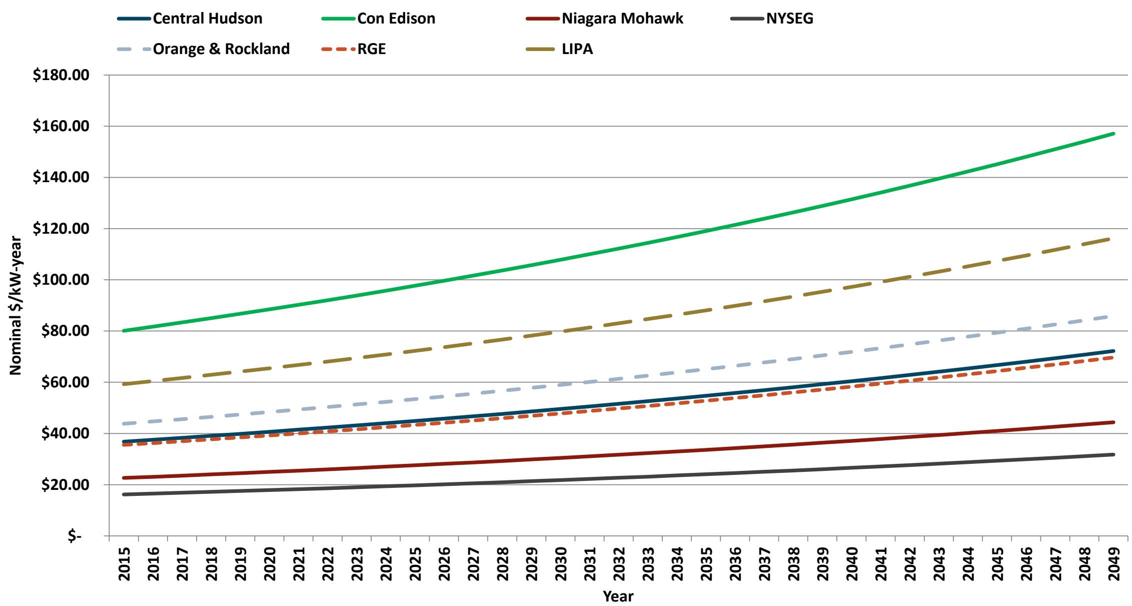
1.4.1.6 Avoided Sub-Transmission Capacity Costs

General Description	Study Calculation Methodology/Value
Reduction or deferral of costs associated with expanding/replacing/upgrading sub-transmission capacity such as area substations, lines, transformers, etc. with the adoption of distributed NEM generation.	Costs based on existing estimates for marginal sub-transmission capacity costs as provided by each utility in their Marginal Cost of Service Studies. These costs are adjusted by the expected sub-transmission system peak load reduction value realized by each type of NEM technology based on NYISO zonal load data.

Sub-transmission capacity costs are the costs of the transmission and distribution system that directly supply distribution substations below the bulk transmission level which generally operates at voltages between 34.5 kV to 138 kV. Sub-transmission capacity costs and definitions vary a great deal between utilities and within different portions of a utility's service territory.

E3 relied on each utility's filed marginal cost of service (MCOS) studies in order to estimate the marginal costs of avoided sub-transmission capacity. We made several adjustments given the non-standard format of the information in the MCOS studies. Most notably ConEd and ORU provided annual marginal cost forecasts which were used while the other utilities provided single point estimates, which we escalated with inflation. Additionally the LIPA MCOS costs were considered outliers and an average of ConEd and Central Hudson costs were used instead.

Figure 17: Sub-transmission Avoided Cost Forecast based on Utility Marginal Cost of Service Studies and E3 Calculations ($/kW-year)



The next step after establishing a marginal sub-transmission capacity cost forecast by utility (adjusting for the appropriate T&D loss savings from distributed NEM systems) is to determine how much of this value can be avoided by a NEM resource. We relied on a PCAF methodology similar to what was used for system capacity price allocations that maps marginal sub-transmission capacity prices to the top zonal peak hours based on zonal load data from 2008-2015. We use zonal load data as a proxy for the loads that drive marginal sub-transmission capacity investments. This methodology assigns a probability to the top 100 zonal load hours as an approximation for the probability of the peak being in a particular hour in that top 100 hours. We then adjust the marginal sub-transmission capacity costs by the assumed coincidence of distributed NEM with the zonal peak load allocations to see how much the generation of distributed NEM generation coincides with the peak loads that drives the marginal sub-transmission investment. This coincidence is how much marginal sub-transmission capacity can be avoided by a distributed NEM system on a system wide average basis.

Figure 18: PCAF Allocators for Sub-Transmission (Zonal Loads)

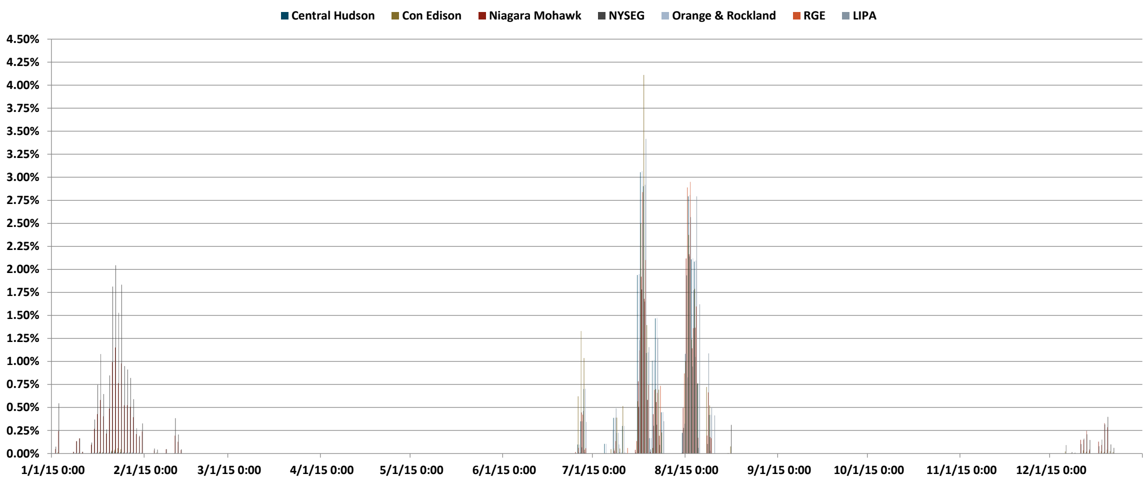


Figure 19: Coincidence of each Utility's Solar PV Profile against Zonal PCAFs

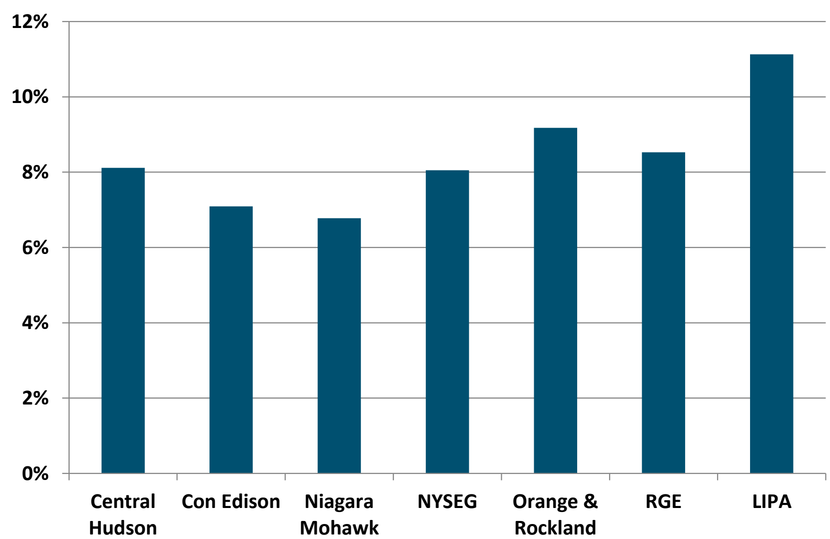
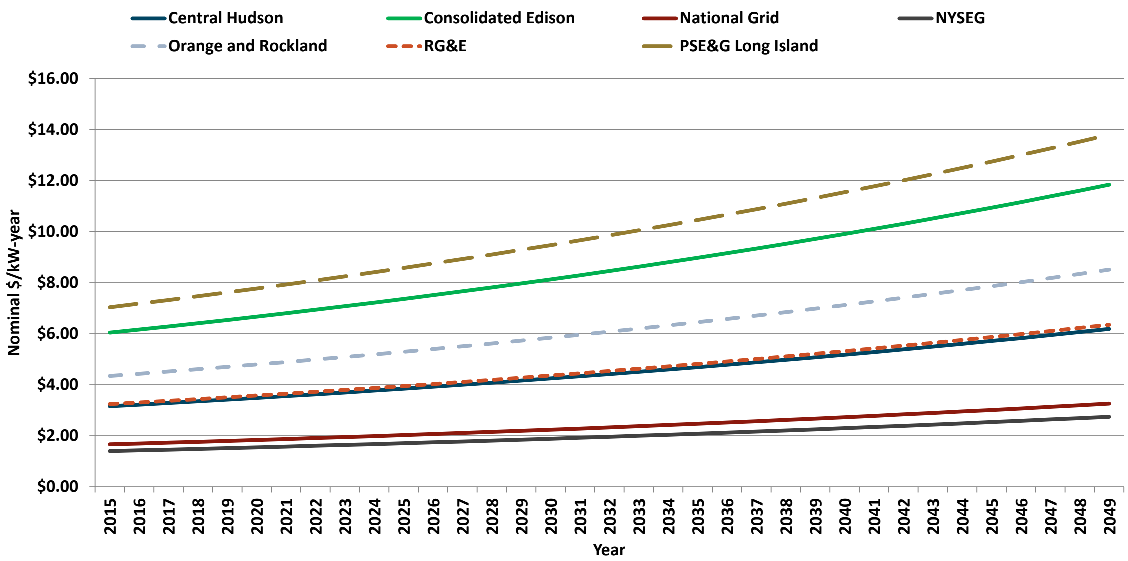


Figure 20: Forecast of Avoided Sub-Transmission Costs Adjusted for Coincidence/Effective Capacity and T&D Losses for each kW of Solar Installed



There are several considerations that are important to note as follows:

- In any follow-up analysis it is recommended that an examination of each utility's capital expenditure plan for sub-transmission capacity additions and/or upgrades be made to determine which specific projects can be deferred or even avoided.
  - PSEG Long Island[47] in a filing made in the current REV proceeding they imply a T&D deferral value of ~$123/kW-year due to adding distributed generation resources looking at the South Fork load pocket. This is one example of a granular analysis that could be pursued, which may become more topical or relevant as the REV proceeding and potentially the treatment of distribution capacity investment evolves and changes over time in New York. Using a more granular analysis to assign value to networks or feeders that could benefit from PV additions would also mean reducing or eliminating the T&D value for night-

[47] https://www.psegliny.com/files.cfm/2014-07-01_PSEG_LI_Utility_2_0_LongRangePlan.pdf

time peaking networks or feeders with abundant spare capacity that receive no T&D benefits from solar PV installations.

+ This information is expected to be filed in each utility's distribution service implementation plan (DSIP)[48] as part of New York's REV proceeding.

1.4.1.7 Avoided Distribution Capacity Costs

General Description	Study Calculation Methodology/Value
Reduction or deferral of costs associated with expanding/replacing/upgrading distribution capacity such as lines, transformers, etc. with the adoption of distributed NEM generation.	Costs based on existing estimates for marginal distribution capacity costs as provided by each utility in their Marginal Cost of Service Studies. These costs are adjusted by the expected distribution system peak load reduction value realized by each type of NEM technology based on utility sample substation load data.

Distribution capacity costs are the costs of the distribution system below the bulk transmission and sub-transmission level which generally operates at voltages below 34.5 kV. Distribution capacity costs and definitions vary a great deal between utilities and within different portions of a utility's service territory.

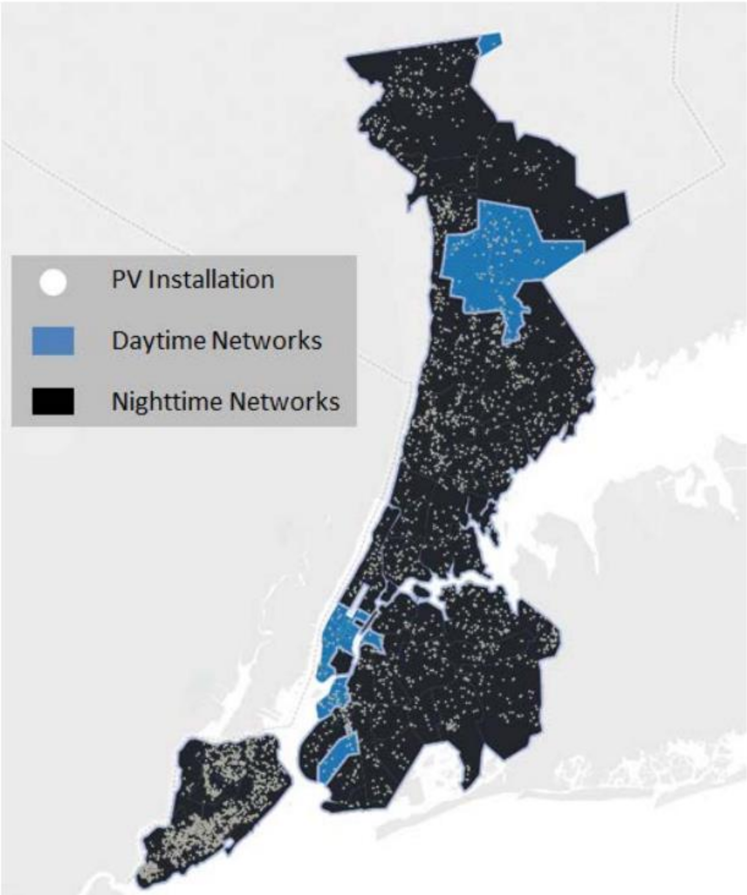
E3 relied on each utility's filed marginal cost of service (MCOS) studies in order to estimate the marginal costs of avoided distribution capacity. We made several adjustments given the non-standard format of the information in the MCOS studies. Most notably ConEd and ORU provided annual marginal cost forecasts which were used while the other utilities provided single point estimates, which we escalated with inflation. Additionally the LIPA MCOS costs were considered outliers and an average of ConEd's non-network costs and Central Hudson costs were used instead.

It is important to note that distribution loads vary greatly depending on the specific distribution feeder and substation load. Customer-sited solar PV generation does not always align with the distribution load peaks that generally drive investment in new distribution capacity, e.g. residential

[48] http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7bF3793BB0-0F01-4144-BA94-01D5CFAC6B63%7d

distribution loads often peak at night after people return home from work when the sun is not shining. Based on E3's NEM Ratepayer Impacts Evaluation[49] in California it was found (in a granular substation load analysis) that distribution peak loads are generally aligned with solar PV generation profiles in approximately 30% of the systems analyzed. This can also be seen for ConEd's distribution network below.

Figure 21: Con Edison Solar Installations in Day vs. Night Peaking Networks[50]



[49] http://www.cpuc.ca.gov/NR/rdonlyres/C311FE8F-C262-45EE-9CD1-020556C41457/0/NEMReportWithAppendices.pdf
[50] http://www.capitalnewyork.com/sites/default/files/CONEDDEMO3.pdf

The next step after establishing a distribution capacity cost forecast by utility (adjusting for the appropriate T&D loss savings from distributed NEM systems) is to determine how much of this value is avoidable by a NEM resource. We relied on granular utility substation load data to map marginal distribution capacity prices to the substation peak hours based on 2012 substation data. We use substation load data as a proxy for the distribution feeder loads that drive marginal distribution capacity investments. This methodology assigns a probability to the top load hours defined as load greater than the rating level of the substation as an approximation for the probability of the peak being in those peak load hours. If that substation rating was not available then a top 100 hour PCAF methodology was used. Note, substation data was only available for ConEd, ORU, NYSEG, and RG&E which were then used to approximate the other utilities in this analysis. We then adjust the marginal distribution capacity costs by the assumed coincidence of distributed NEM with the substation peak load allocations to see how much the generation of distributed NEM generation coincides with the peak loads that are driving the marginal distribution investment. This coincidence informs how much marginal distribution capacity can be avoided by a distributed NEM system on a system wide average basis.

Figure 22: Mapping of NY Utilities to Substation Load Data

Utility	Substation Load Data
NYSEG	NYSEG
National Grid: (Niagara Mohawk)	NYSEG
Rochester Gas & Electric	Rochester Gas & Electric
Consolidated Edison	Consolidated Edison
Central Hudson Gas and Electric	Orange and Rockland Utilities
Orange and Rockland Utilities	Orange and Rockland Utilities
PSEG Long Island	Consolidated Edison

Figure 23: Distribution Avoided Cost Forecast based on Utility Marginal Cost of Service Studies and E3 Calculations ($/kW-year)

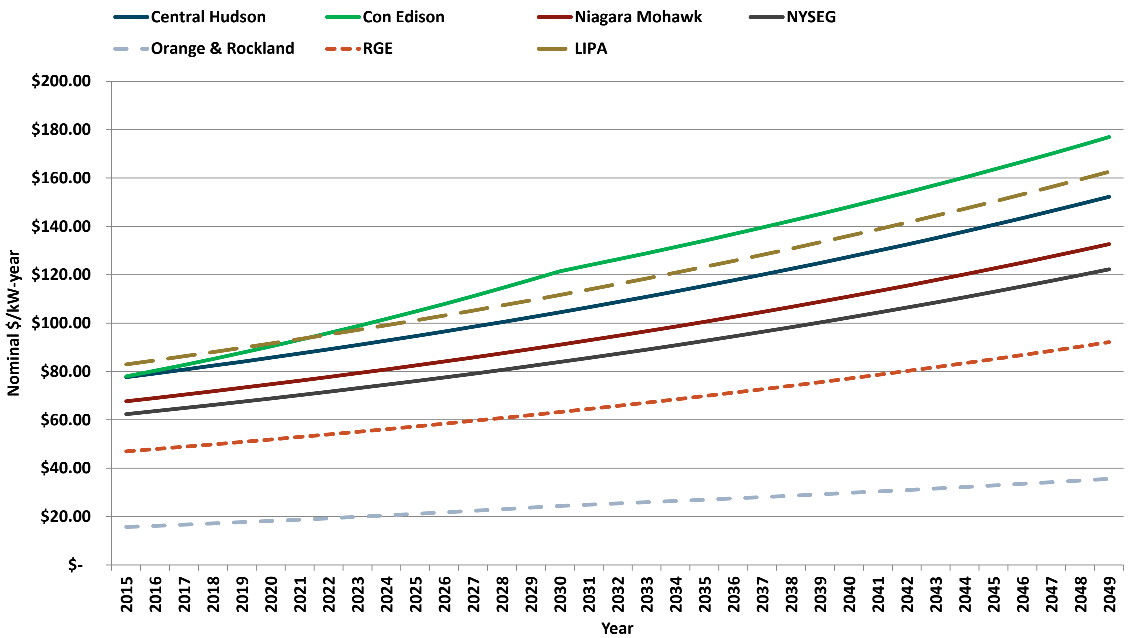


Figure 24: Allocators for Distribution (Substation Loads)

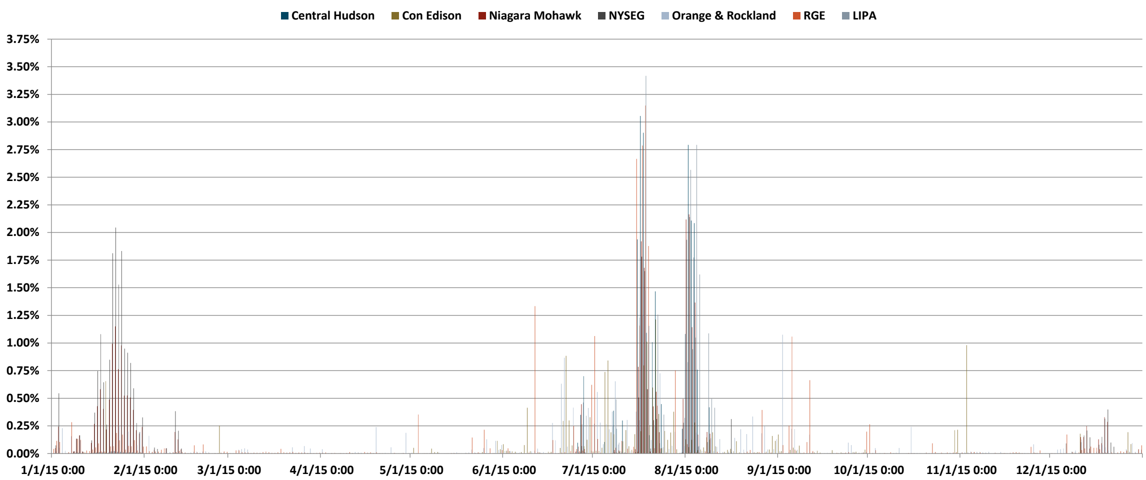


Figure 25: Coincidence of each Utility's Solar PV Profile against Substation Allocators

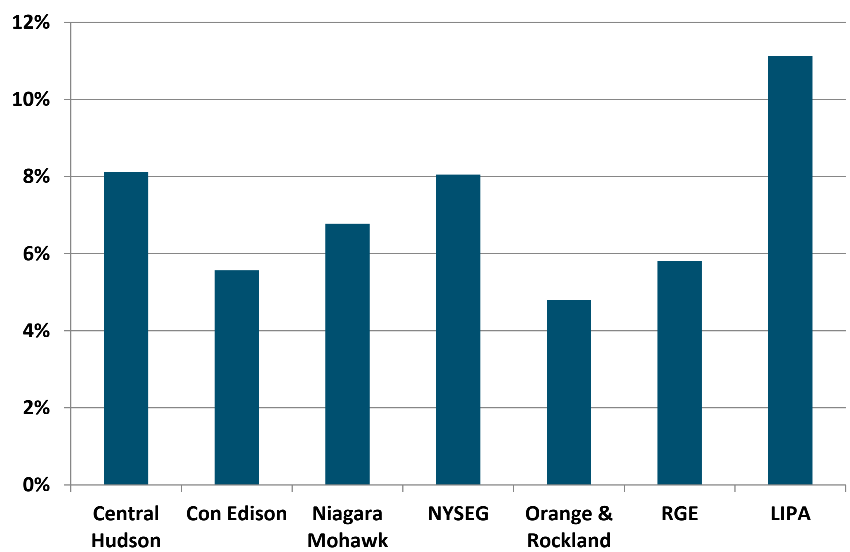
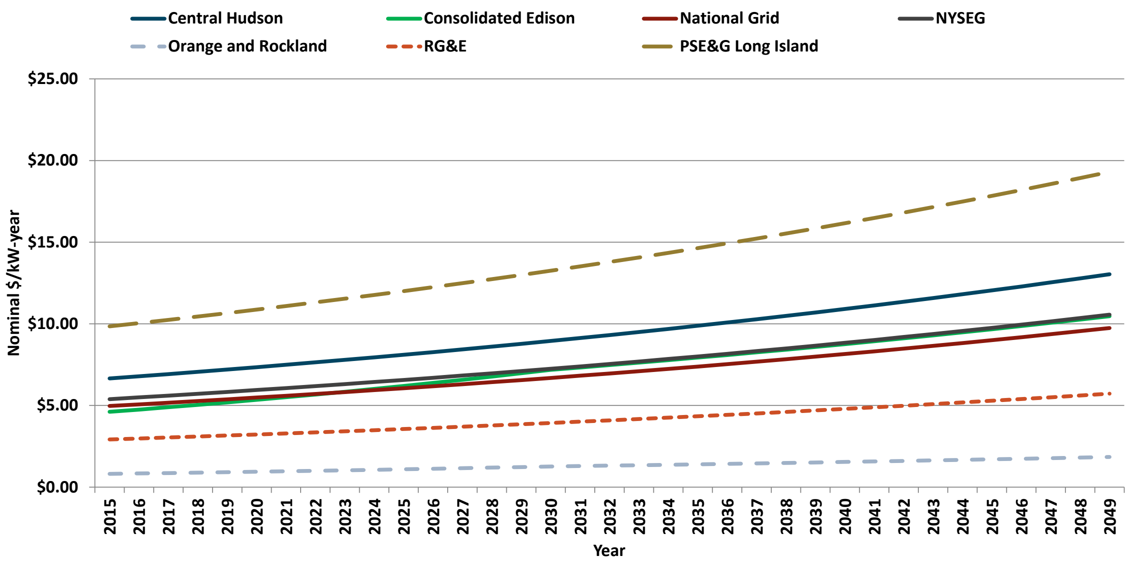


Figure 26: Forecast of Avoided Distribution Costs Adjusted for Coincidence/Effective Capacity and T&D Losses for each kW of Solar Installed



There are several considerations that are important to note as follows:

+ In any follow-up analysis it is recommended that an examination of each utility's capital expenditure plan for distribution capacity additions and/or upgrades be made to determine which specific projects can be deferred or even avoided.

*1.4.1.8 Renewable Portfolio Standards (RPS) Value**

General Description	Study Calculation Methodology/Value
Reduction of the compliance costs associated with utilities obligated to procure certain renewables to meet Renewable Portfolio Standards (RPS) associated with the adoption of distributed solar.	No value assigned because there is currently no RPS compliance requirement or market in NY such as a requirement for each utility to procure a certain number Renewable Energy Certificates (RECs) or procure certain amounts of renewables to serve its load, therefore the adoption of distributed solar does not avoid this future cost. E3 identifies this component explicitly as one requiring further study, especially if a renewable compliance market is developed in NY.

For the RPS value E3 chose a proxy value of zero. Under New York's current RPS,[51] it is assumed there are currently no avoided or displaced future renewable purchases or REC value benefits due to adoption of distributed NEM.

There are several considerations that are important to note as follows:

+ In many jurisdictions there is often a benefit with NEM installations that can reduce the obligation of the utility to purchase renewables to meet state RPS compliance requirements, which is a potential avoided cost benefit.
    - In New York the RPS program is structured uniquely compared to other states where in New York funds are used to procure renewables and the RPS targets are non-binding with no financial penalty or costs for non-compliance.
    - Therefore no savings are assumed to occur due to NEM system adoptions.
+ If a REC or avoided RPS value is adopted in the future it is important to note that the baseline of this framework analysis may have to change. For example, if there is a future RPS or REC compliance market and a non-zero avoided RPS or REC value is included in this methodology calculation then certain other components would thereby be zero. If you assume that the current purchase and installation of customer-sited solar PV displaces future purchases of renewables mandated by a future RPS then the methodology baseline will change as follows:
    - Rather than assuming a baseline that the New York electricity market will supply the resources to meet future load it is assumed that the resources that are displaced are not market resources, but rather future renewables. This means that the carbon, criteria pollutant, market price effect, and fuel hedge (if any) benefit components should be zero because the future renewable that is being displaced would presumably have had the same benefits. In other words only the cost of procuring that future renewable or REC, e.g. from a wind farm or utility-scale solar PV station, is avoided.

51 http://www.nyserda.ny.gov/Publications/Program-Planning-Status-and-Evaluation-Reports/Renewable-Portfolio-Standard-Reports.aspx

1.4.1.9 Avoided Criteria Pollutants

General Description	Study Calculation Methodology/Value
Reduction of SO_x, NO_x, and PM_{10} emissions due to reduction/increase in production from the marginal wholesale generating resources associated with the adoption of distributed solar generation.	The compliance costs associated with these criteria pollutants is included in the zonal energy cost NYISO CARIS forecasts.

For avoided criteria pollutant costs E3 chose a value of zero in this initial methodological framework analysis. This is because the compliance costs for SO_x and NO_x are already explicitly included in the avoided energy cost component (NYISO zonal LBMP forecast from the CARIS results).

There are several considerations that are important to note as follows:

+ In any follow-up analysis E3 recommends further study to determine what the marginal criteria pollutant emission rates are in order to more fully reflect the resources potentially being displaced by distributed NEM resources.

1.4.1.10 Monetized CO_2 Emissions Cost

General Description	Study Calculation Methodology/Value
Reduction of CO_2 emissions due to reduction in production from the marginal wholesale generating resources associated with the adoption of distributed NEM generation.	The monetized value of carbon as determined by the NYISO in its CARIS forecast.

For avoided monetized carbon or CO_2 emission costs E3 chose values based on the forecast costs that are already explicitly included in the NYISO zonal forecasts from the CARIS results. This forecast represents the NYISO zonal projections on what carbon costs will be over the CARIS I analysis period which again spans 2015-2024. This represents the “monetized” or actual compliance costs that will presumably be embedded in future LBMPs. After 2024 E3 assumes that the forecast carbon allowance costs remain constant in real terms and only adjust for inflation. Note, this analysis does not explicitly model the RGGI cap and trade market, but rather assume carbon costs as modeled by the NYISO.

Figure27: NYISO $/Ton Forecast of Monetized Carbon Allowance Forecast Costs[52]

Year	NYCA CARIS Forecast Carbon Costs (nominal $/ton)
2015	$5.75
2016	$8.02
2017	$10.12
2018	$10.48
2019	$10.99
2020	$14.67
2021	$15.70
2022	$16.57
2023	$17.54
2024	$18.48

The marginal CO_2 emission rate was determined by using EPA eGrid data[53] for NY specific generators to determine average annual marginal emission rates for natural gas, oil, and coal plants along with information on which of these fuels were on the margin based on the 2014 NYISO State of the Market report[54]. This same methodology is used when translating the Societal Benefits, i.e. Social Cost of Carbon $/ton forecast, to a $/MWh forecast described further below.

[52] http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_espwg/meeting_materials/2015-07-07/0707115%20ESPWG%202015%20CARIS%20Base%20Case%20%20Final.pdf
[53] http://www.epa.gov/cleanenergy/energy-resources/egrid/
[54] http://www.nyiso.com/public/webdocs/markets_operations/documents/Studies_and_Reports/Reports/Market_Monitoring_Unit_Reports/2014/NYISO2014SOMReport__5-13-2015_Final.pdf

Figure 28: Marginal Emission Rate Analysis for CO_2

CO_2	Percent of Marginal Intervals[1]	Hydro Adjustment[2]	Pounds per MWh[3]	Tons per MWh	Tons per MWh (Weighted)
Nuclear	0	0			
Hydro	45	0			
Coal	7	7	2,075.2	1.03759	0.05263
NG	76	121	1,032.4	0.51621	0.45261
Oil	6	6	1,527.7	0.76383	0.03321
Wind	4	4			
Other	0	0			
Total	138	138			**0.538456**

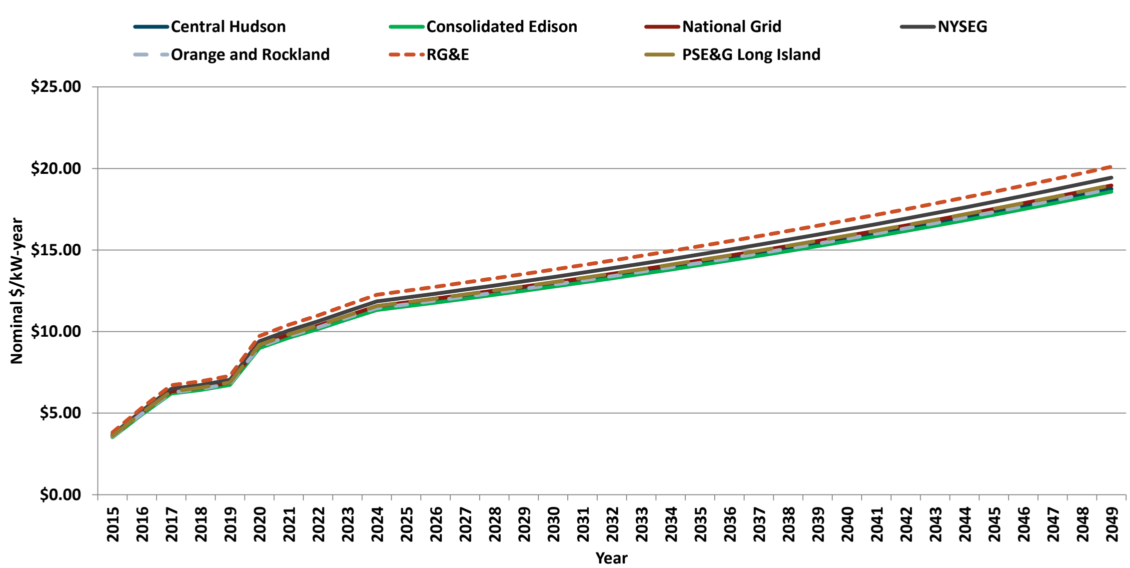
[1]NYISO 2014 State of the Market Report.

[2]Per report, most hydro is storage and therefore converted to NG for the purpose of this analysis.

[3]Based on EPA eGrid data for NY generators

The figure below shows the statewide carbon costs avoided by each utility due to distributed solar PV production. The statewide forecast varies slightly by utility since the simulated solar PV production varies by utility.

Figure 29: $/kW-yr Forecast of Avoided Statewide Monetized Carbon Costs by Utility



There are several considerations that are important to note as follows:

- E3 recommends this component be monitored as the debate for carbon allowance markets evolve both in New York and the U.S., especially given EPA's proposed Clean Power Plan under Section 111(d) of the Clean Air Act.[55]

- Also there is an important consideration when calculating marginal emission rates over time, specifically with the assumption of what kind of generating unit will be on the margin. In other words, this forward looking analysis assumes that the types of marginal units don't change throughout the study period, consistent with what was reported in the 2014 State of the Market report for a single year. This may change over this analysis period, especially if more natural gas or renewables are on the margin. If for example if more wind becomes the marginal resource then there would be no CO2 emissions on the margin for those intervals. This is something that should be monitored as New York adds more renewables to its system.

1.5 Market Price Effect

General Description	Study Calculation Methodology/Value
Potential reduction of system wide wholesale energy costs due to reduced system load attributable to distributed NEM generation.	There are many factors that affect this component including how much the current and forecast NY wholesale energy market is at spot vs. hedged or under long-term contracts. Additionally, information on the underlying market and operational characteristics are needed to see how much if any supply can be affected and for how long due to distributed NEM PV generation now and in the future.

There are many factors that affect this component including how much the current and forecast NY wholesale energy market is at spot vs. hedged or under long-term contracts. Additionally, information on the underlying market and operational characteristics are needed to see how much if any supply can be affected and for how long due to distributed NEM PV generation now and in the future.

[55] http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule

E3 identifies this component explicitly as one requiring further study but a proxy value was calculated using the NYISO high solar PV case as part of its CARIS I study[56]. An average LBMP market price effect was calculated to be approximately $15.00/MWh for each incremental MWh of solar generation on a statewide basis after adjusting for the amount of the day-ahead market assumed to be hedged (~40%). This effect is assumed to decrease by 50% in the following year to $7.50/MWh and then to zero in the 3rd year consistent with the guideline in the DPS BCA.

The NYISO zonal and nodal electricity market clearing price is currently set by the marginal generating unit (usually a natural gas fired unit) and as you reduce load such as with behind-the-meter solar PV generation then the market clearing price can potentially be lowered for the entire system (at least in the short-term) if you can step down the supply curve with the reduced demand and dispatch a more efficient, i.e. less expensive, marginal generating unit than you otherwise would have.

There are several considerations that are important to note as follows:

+ This is a specific component in which further study is required. There are many factors that affect this component including how much the current and forecast NY wholesale electricity market is at spot at each geographic location, i.e. clearing price determined by the marginal generating unit vs. how much of electricity is hedged at a fixed price whose price therefore does not respond to the amount of demand or load being served.
    - This also depends on the particulars of the various NYISO energy and capacity zones and their respective generation supply stack setting the market clearing price. Further analysis would have to be done to quantify this effect accurately as well to determine how long this effect would persist.
+ Additionally there are several well established issues in regards to calculating this type of benefit as stated below:

[56] http://www.nyiso.com/public/webdocs/markets_operations/committees/bic/meeting_materials/2015-08-12/agenda%203%20Market%20Operations%20Report_%20BIC_08.12.15.pdf

- There are many market supply and demand considerations and isolating the effects of customer-sited solar PV on demand is difficult and often times unclear.
- Customers could respond to lower energy prices by consuming more electricity which would counteract any downward pressure on prices. Generators could also respond to lower energy prices by forgoing certain capital or O&M expenditures, mothballing/retiring units or not entering the market in the first place. This would also counteract any downward pressure on prices. Depending on the speed of the reaction of both the demand and supply side of the market any price decrease could be short lived.
- This represents a transfer payment from NY generators to NY ratepayers. If wholesale market prices are lowered then owners of existing generating capacity could allow their assets to become less efficient and reliable as low prices make continued operation of the units less attractive, leading to more outages and/or higher market clearing prices (all else being equal).
- Further, lower energy market revenues would increase net cost of new entry (CONE) and tend to increase capacity prices as generators would need additional capacity payment revenue to build new resources. Additionally, baseload units would become less desirable given lower energy market revenues which would be replaced with smaller, more modular generating units like combustion turbines. This avoidance or prevention of baseload units being built in the future means that the market price effect from those units is foregone.

1.6 Indirect Benefits

1.6.1 SOCIAL CARBON

General Description	Study Calculation Methodology/Value
Changes in agricultural productivity, human health impacts, property and infrastructure damages from increased flood risk, and the value of ecosystem service losses due to climate change.	E3 identifies this component explicitly as one requiring further study in order to establish the appropriate New York specific social carbon or societal benefit applicable in this analysis. For the purpose of this study the EPA social cost of carbon was relied upon[57] minus the monetized CO_2 emission cost forecast from the NYISO CARIS. This EPA forecast assumes different levels of discount rates to determine the cost of carbon. The emission rate was determined by using EPA eGrid data[58] for NY specific generators to determine average annual marginal emission rates for natural gas, oil, and coal plants along with information on which of these fuels were on the margin based on the NYISO State of the Market report[59].

[57] http://www.epa.gov/climatechange/EPAactivities/economics/scc.html
[58] http://www.epa.gov/cleanenergy/energy-resources/egrid/
[59] http://www.nyiso.com/public/webdocs/markets_operations/documents/Studies_and_Reports/Reports/Market_Monitoring_Unit_Reports/2014/NYISO2014SOMReport__5-13-2015_Final.pdf

The 3.0% EPA's Social Cost of Carbon[60] forecast (adjusted for inflation) minus the NYISO monetized carbon cost forecast was selected as a proxy value for New York societal benefits (see below) associated with reducing marginal CO_2 emissions from generators. E3 subtracted the monetized

Social Cost of CO_2, 2015-2050 [a] (in 2011 Dollars)

Year	Discount Rate and Statistic			
	5% Average	3% Average	2.5% Average	3% 95th percentile
2015	$12	$39	$61	$116
2020	$13	$46	$68	$137
2025	$15	$50	$74	$153
2030	$17	$55	$80	$170
2035	$20	$60	$85	$187
2040	$22	$65	$92	$204
2045	$26	$70	$98	$220
2050	$28	$76	$104	$235

[a] The SCC values are dollar-year and emissions-year specific.

carbon cost forecast from the EPA forecast in order to reflect the fact that some of those monetized carbon costs represent the "internalization," i.e. monetization, of certain social costs included in the EPA carbon cost forecast.. The calculation methodology E3 uses in determining the avoided monetized CO_2 costs were applied to the EPA $/ton forecast to develop a tons/MWh assumed marginal CO_2 emission rate to determine a $/MWh forecast to apply to net metered generation for each utility.

[60] http://www.epa.gov/climatechange/EPAactivities/economics/scc.html

Figure 30: $/ton Forecast of EPA Social Carbon Costs by Utility Net of NYISO CARIS Carbon Forecast Costs

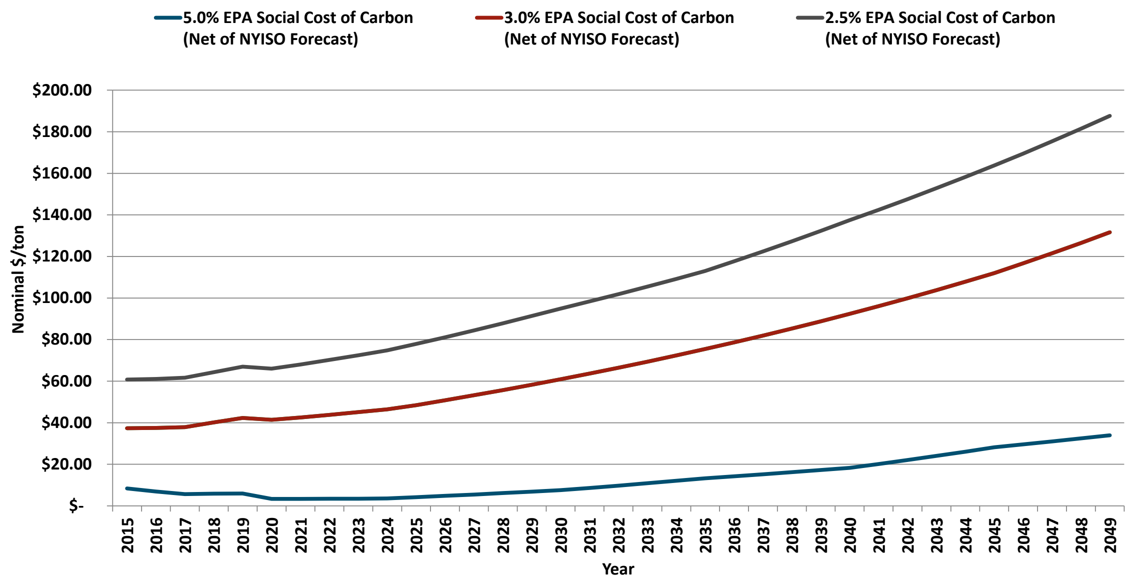
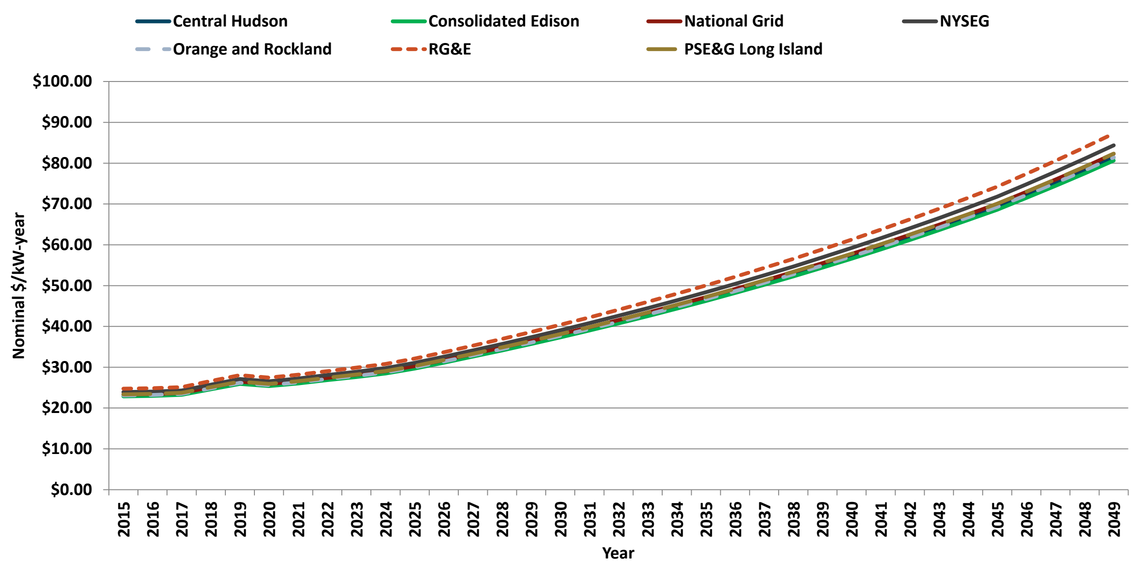


Figure 31: Social Carbon Cost Forecast based 3.0% EPA Social Cost of Carbon Forecast (Net of NYISO Monetized Carbon costs) by Utility ($/kW-year)



There are several considerations that are important to note as follows:

- This is a specific component where further study is required. There are many factors that affect this component including many externalities and other hard to evaluate factors that are very difficult to quantify.
- The full benefit (*i.e*. global benefit) is included in the Societal Cost Test in this analysis as the proxy value for the Social Cost of Carbon. Alternatively the Social Cost of Carbon could be de-rated by some amount to estimate only impacts to New York State.

1.6.2 HEALTH BENEFITS

General Description	Study Calculation Methodology/Value
Reduction of non-emission related health benefits such as decreased mortality rates, reduced asthma attacks, etc. associated the adoption of distributed solar.	These externalities are often difficult to estimate. E3 identifies this component explicitly as one requiring further study in order to establish the appropriate New York specific externalities that should be examined. For the purpose of this study high level estimates from the EPA for the costs of SO_2 and Nox related health impacts are used. These estimates assume different levels of discount rates to determine the damage values, which are used in conjunction with the marginal emission rates of SO_2 and Nox derived from the EPA's eGrid data similar to the methodology described above for CO_2 emissions.

The first step in estimating the cost of the health impacts associated with the marginal emissions of SO_2 and Nox from generators is to estimate the marginal emission rates of SO_2 and Nox. The tables below show how the marginal emission rates were estimated, which is the same methodology used to estimate the marginal emission rate of CO_2 for New York generators.

Figure 32: Marginal Emission Rate Analysis for SO_2

SO_2	Percent of Marginal Intervals[1]	Hydro Adjustment[2]	Pounds per MWh	Tons per MWh	Tons per MWh (Weighted)
Nuclear	0	0			
Hydro	45	0			
Coal	7	7	6.5	0.00326	0.00017
NG	76	121	0.1	0.00006	0.00005
Oil	6	6	3.3	0.00163	0.00007
Wind	4	4			
Other	0	0			
Total	138	138			**0.000290**

[1]NYISO 2014 State of the Market Report.

[2]Per report, most hydro is storage and therefore converted to NG for the purpose of this analysis.

[3]Based on EPA eGrid data for NY generators

Figure 33: Marginal Emission Rate Analysis for Nox

Nox	Percent of Marginal Intervals[1]	Hydro Adjustment[2]	Pounds per MWh	Tons per MWh	Tons per MWh (Weighted)
Nuclear	0	0			
Hydro	45	0			
Coal	7	7	2.1	0.00105	0.00005
NG	76	121	0.4	0.00020	0.00017
Oil	6	6	2.4	0.00122	0.00005
Wind	4	4			
Other	0	0			
Total	138	138			**0.000281**

[1]NYISO 2014 State of the Market Report.

[2]Per report, most hydro is storage and therefore converted to NG for the purpose of this analysis.

[3]Based on EPA eGrid data for NY generators

The costs or value associated with the reduction on NO_x and SO_x were estimated using the method developed by the EPA[61]. In this EPA Technical Document, industry specific $/ton reduction values were developed for SO_x and NO_x based on the changes in health status expected to occur due to changes in pollutant concentrations. Health status changes include

[61] http://www2.epa.gov/sites/production/files/2014-10/documents/sourceapportionmentbpttsd.pdf

the number of chronic disease cases, the number of days of acute morbidity effects, and the number of statistical lives lost. In this analysis we use the values from Krewski and Lepeule along with the calculated midpoint value.

Figure 34: SO_2 Health Impact Cost Forecast Based on EPA Damage Value Estimates (Net of NYISO SO_2 Forecast)

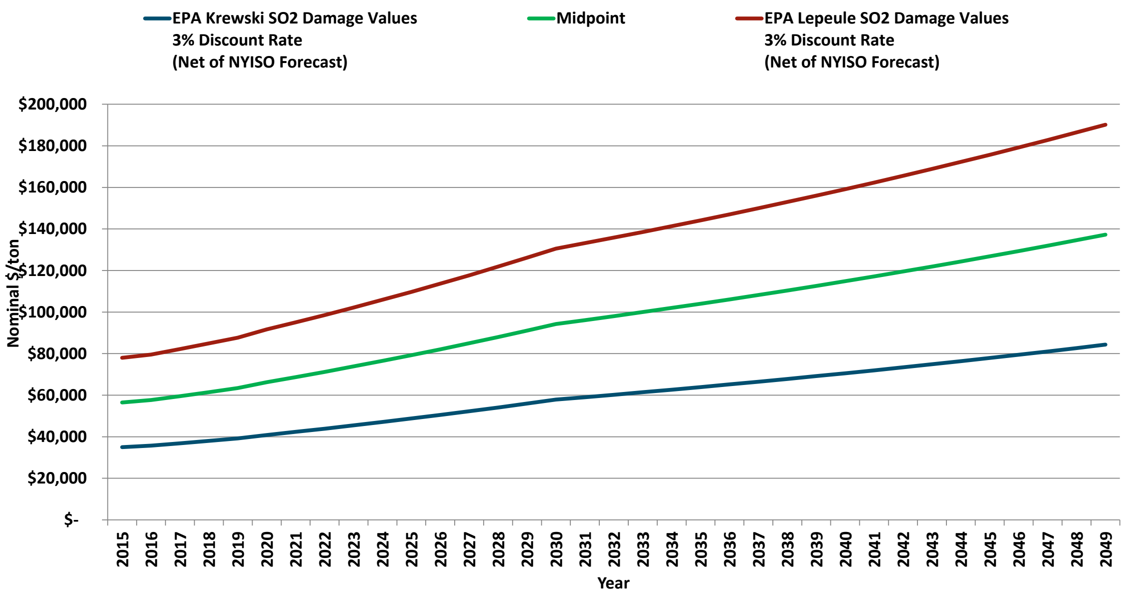
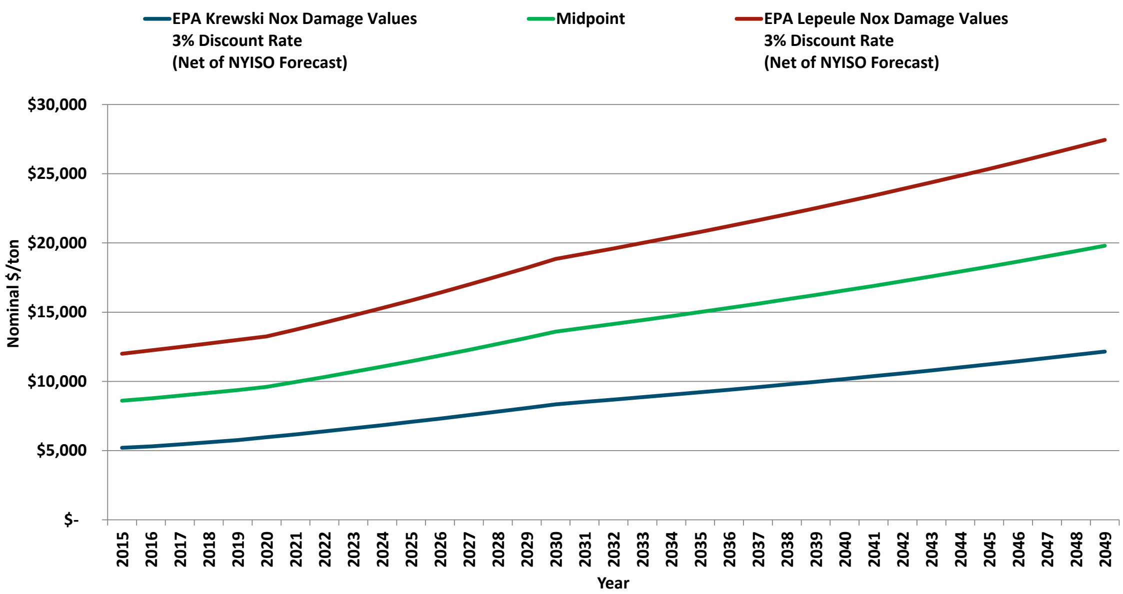


Figure 35: Nox Health Impact Cost Forecast Based on EPA Damage Value Estimates (Net of NYISO Nox Forecast)



These $/ton values are then converted using the assumed marginal emission rates to determine the marginal values.

Figure 36: Health Impact Forecast for SO_2 based on Midpoint of EPA Damage Valuation (Net of NYISO Monetized SO_2 Costs) by Utility ($/kW-year)

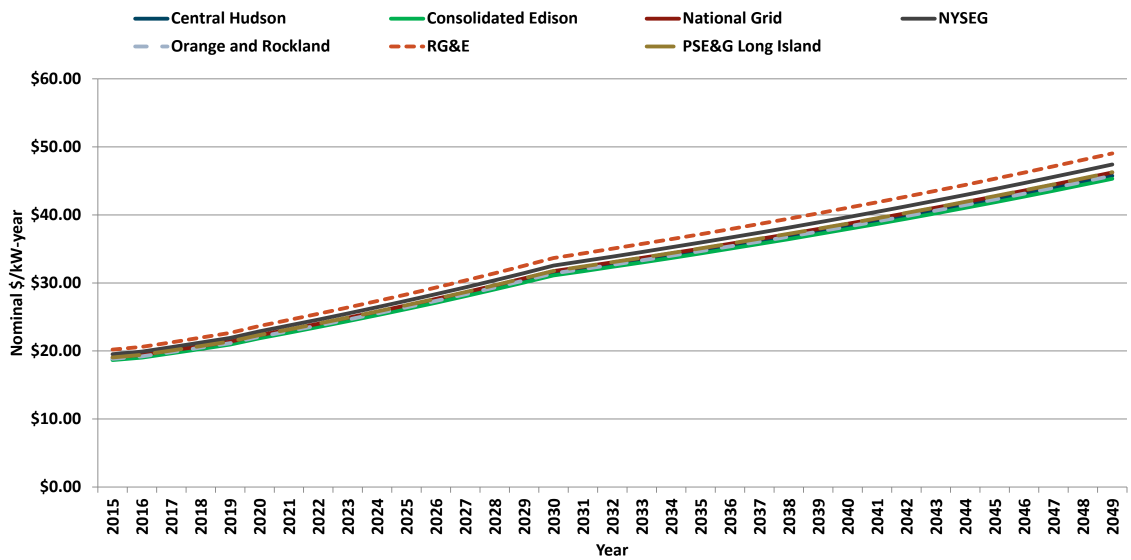
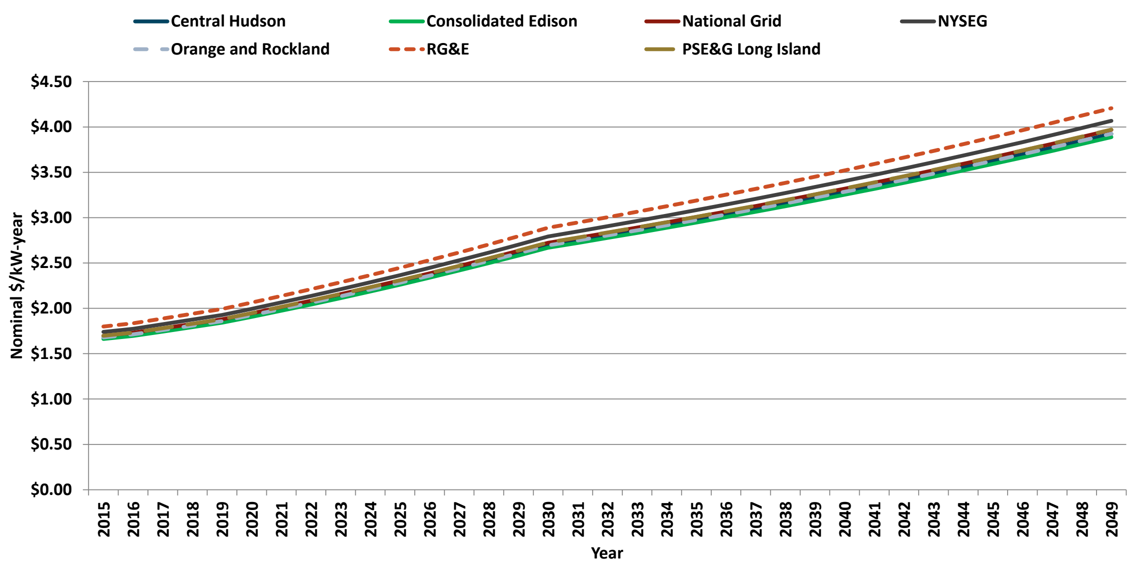


Figure 37: Health Impact Forecast for Nox based on Midpoint of EPA Damage Valuation (Net of NYISO Monetized Nox Costs) by Utility ($/kW-year)



There are several considerations that are important to note as follows:

- This is a specific component where further study is required. There are many factors that affect this component including many externalities that are very difficult to quantify.
- Again, an important consideration in calculating marginal emission SO_2 and NOx rates over time is determining what type of generating unit will be on the margin. In other words, this forward looking analysis assumes that the types of marginal units are the same as what was reported by the NYISO State of the Market report. This may change over this analysis period, especially if more natural gas or renewables are on the margin. This is something that should be monitored as New York adds more renewables to its system.

1.7 Bill Savings

General Description	Study Calculation Methodology/Value
Reduction in customer electricity bills due to behind the meter generation.	Based on Clean Power Estimator Tool bill savings for each utility and class. Standard assumptions on system sizing, rate schedules composing each class, percent of customers on time-variant rates, and others are explained in more detail below. E3 subtracts out the Clean Power Estimator energy supply charge and adds in our own energy market price forecast for the energy component of bill savings.

E3's bill savings values (in $/kWh) are based primarily on the Clean Power Estimator Tool developed by Clean Power Research (CPR) for NYSERDA.[62] To get bill savings values from this tool E3 ran a standard sized (50-70% of consumption from solar generation) solar PV system for every available net metered rate class for each utility and area through the tool. E3 then took

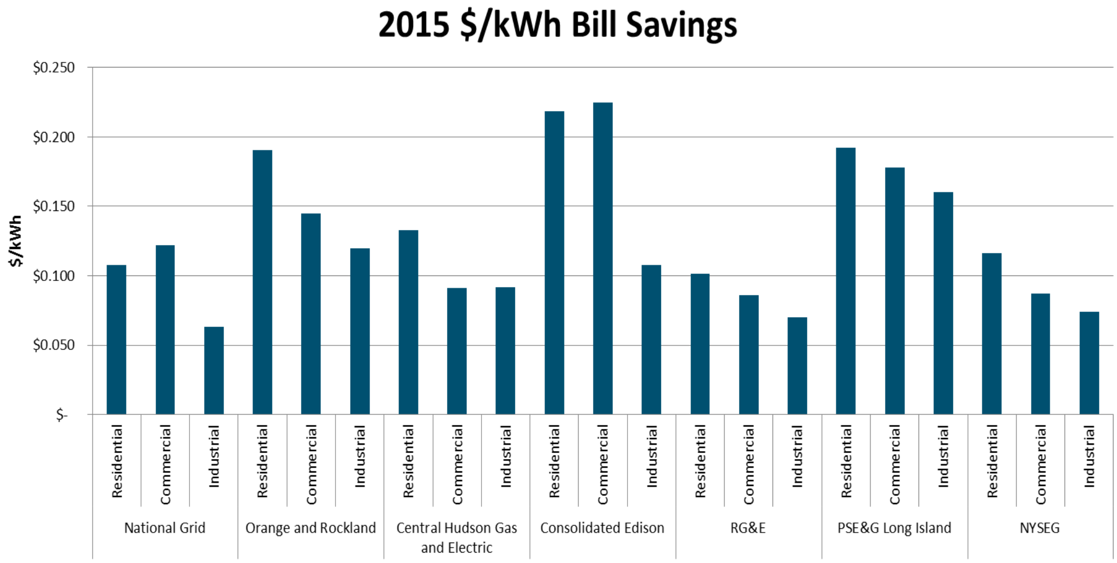
[62] http://ny-sun.ny.gov/Get-Solar/Clean-Power-Estimator

total bill savings ($) and divided by total solar production (kWh) to determine $/kWh bill savings at both a monthly and annual level.

Because the CPR tool gives results according to rate schedule by utility (e.g. SC1, SC2, etc.) and E3's cost tests are done for a standard class (e.g. Residential) by utility, E3 then assigned weights to each rate schedule based on the fraction of net metered customers in each class expected to be on that rate schedule. For residential rates this is relatively straightforward – most utilities have a single default residential rate with a little-used time-of-use option(s). For Small and Large Non-residential customers there are generally multiple rate schedules with varying bill savings based on differences in demand charges, time of use charges, etc. To assign customers to a CPR rate schedule within these classes, E3 estimated the size of existing net metered customer consumption based on their PV installation (e.g. Small Commercial systems assumed to serve 60% of customer load on average) and assigned these customers to the corresponding tariff used by utilities for a representative customer close to this size in data received by E3. Bill savings for the class are then a weighted average of customer level bill savings according to kWh consumption assumed on each rate schedule within that class. Some other small adjustments are made to modify CPR data for use in the E3 model (e.g. CPR provides bill savings for ConEd Zone J and ConEd Zone I/H separately; E3 combines these numbers in a load weighted average to use a single ConEd value).

E3 further modified CPR's bill savings numbers to incorporate the energy market forecast developed by E3. Because energy market charges are a pass-through in rates, future electric rates and bill savings will reflect future energy market charges. E3 obtained CPR's assumptions for energy market charges by utility and class, subtracted these off from the calculated bill savings, and called the residual value the non-energy (i.e. transmission and distribution) bill savings. E3 then added back in its energy market forecast to obtain bill savings numbers.

The results of this methodology are shown by utility and class below.



1.8 Program Costs

General Description	Study Calculation Methodology/Value
Increase of costs borne by the utility to administer NEM customers.	Incremental costs associated with NEM such as billing of net metering customers as well as other administrative costs. An assumed value of $1-$3/MWh is used in this analysis depending on the scenario.

Program costs are the costs to the utility of implementing and maintaining distributed energy resource programs like NEM. These costs usually consist of administrative program costs which may include a one-time setup cost associated with installing a bi-directional meter necessary for net metering, as well as ongoing annual costs of staff and other expenses required to maintain the program. It is assumed at low penetrations this cost is relatively low. Thus, E3 assumes a fixed $1-$3/MWh cost adder as a proxy value applied to all NEM generation for all utilities in depending on the scenario examined.

There are several considerations that are important to note as follows:

- E3 recommends in any follow-up analysis that these potential costs be examined in more detail on a utility by utility basis as well as by class to determine the actual utility costs incurred to manage the NEM program.

1.9 Integration Costs

General Description	Study Calculation Methodology/Value
Increase of costs borne by the utility to interconnect and integrate distributed NEM including increases in ancillary services like operating reserves, voltage control, etc.	This can be examined most easily based on detailed studies and/or literature reviews[63] that have examined the costs of integration and interconnection associated with the adoption of NEM. An assumed value of $1-$3/MWh is used in this analysis depending on the scenario.

Some types of NEM generation like solar PV are inherently a non-dispatchable, intermittent resource. A New York utility may incur additional operational costs when it acts to adjust to sudden changes in renewable output, referred to as integration costs (all else being equal). These costs typically manifest through increases in regulation reserve requirements and other ancillary services.

After conducting a literature review of several renewable integration cost studies in the US,[64] E3 selected an integration cost proxy value of $1-$3/MWh, applied to all NEM generation. Estimates within these studies range from $0/MWh to $18/MWh with the vast majority of estimates in the single digits although at higher NEM penetrations of solar PV this cost could approach $10/MWh. This could occur especially if solar PV adoption triggers distribution upgrades and/or increased grid support charges like increasing amount of voltage

[63] A topical report is a Duke Energy/US Department of Energy study of solar integration in the Carolinas available at http://www.duke-energy.com/pdfs/carolinas-photovoltaic-integration-study.pdf.

[64] A topical report is a Duke Energy/US Department of Energy study of solar integration in the Carolinas available at http://www.duke-energy.com/pdfs/carolinas-photovoltaic-integration-study.pdf. *Large-Scale PV Integration Study*, Navigant Consulting, 2011
Integrating Solar PV in Utility System Operations, Argonne National Laboratory, 2013
Solar Photovoltaic Integration Cost Study, Black and Veatch, 2012
Distributed Generation Study, Navigant Consulting, 2010

control/reserves. E3 intentionally selected an integration cost lower that those reported because most of the available literature focuses on large-scale solar installations, which present larger intermittency problems than distributed solar PV because it is less geographically diverse. It is assumed that on average the level of NEM generation is likely small enough (on a disaggregated local basis) where it will not greatly affect normal operations such as voltage levels and not lead to backflows which would trigger an in-depth interconnection study.

FERC's Small Generator Interconnection Process[65] and California Rule 21[66] use a 15% penetration trigger for in-depth interconnection studies. Distributed generation penetration levels lower than 15% of peak circuit load are not considered at risk for causing voltage or backflow issues. Moreover, high distributed generation penetration studies in Hawaii find that much larger penetration levels do not cause voltage issues. Even when Kauai Island Utility Cooperative supplies 90% of distribution load with PV during the day, voltage remains within the +/- 5% tariff limit.[67]

There are several considerations that are important to note as follows:

+ Any follow-up analysis should examine these potential costs in more detail on a utility by utility basis through an in-depth study to determine how solar PV integration will affect utility operations and if larger costs than assumed in this report are warranted.

1.10 NEM Installation Costs

NEM participants have the option of purchasing solar PV installations outright or contracting with a third party system owner and installer. Participants often sign a power purchase agreement (PPA), in which the third party owns the system and the participant purchases the generated energy. Over time, the third party ownership model has become increasingly

[65] FERC SGIP § 2.2.1.2
[66] See http://www.cpuc.ca.gov/PUC/energy/Procurement/LTPP/rule21.htm
[67] Bank, J, B. Mather, J. Keller, and M. Coddington (2013). "High Penetration Photovoltaic Case Study Report." National Renewable Energy Laboratory Technical Paper.

common, likely because it presents little upfront financial hurdle and relieves customers of maintenance obligations while achieving some immediate electric bill savings.

As a simplifying assumption, this study models all distributed solar PV systems as installed and financed through a third-party provider where the customer purchases generated electricity over the lifetime of the system (assumed to be 25 years). E3 expects the third-party provider ownership model to be the most common form of ownership going forward in New York, justifying the assumption. For systems installed using different financing mechanisms, such as a third party lease or a participant's upfront cash purchase, this simplifying assumption enables a high level cost-effectiveness analysis without reconstructing the individual financing of the over 30,000 currently installed systems in New York. E3 believes this a reasonable simplification because this analysis aims to provide a first order approximation of the benefits and costs of solar PV resources[68] in New York.

A pro forma model is used to convert upfront installation costs, operations and maintenance (O&M) costs, tax credits, and the NY-Sun MW Block Incentives[69] into an expected PPA price paid by the NEM participant to a third party installer/owner. The model takes into account the tax benefits and financing costs incurred by the third party owner. The pro forma methodology and inputs are described in more detail below.

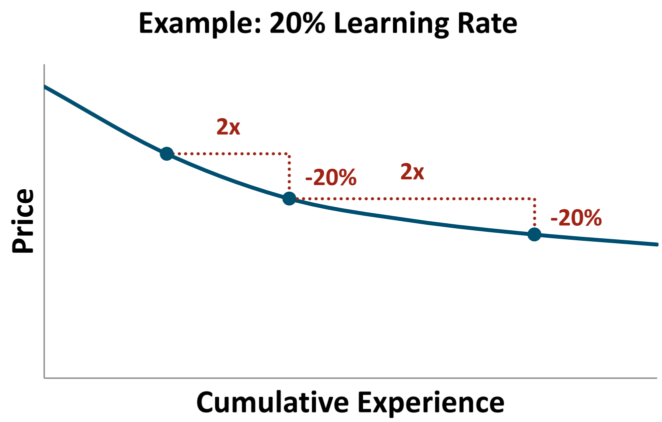
1.10.1 CAPITAL COSTS

To calculate 2015 capital costs, E3 used a NYSERDA provided NY-Sun database dated June 2015 that contained cost and other data for over 30,000 existing solar PV systems. As part of this review E3 examined the cost data in detail. To determine solar PV costs after 2015 E3 developed a New York specific cost forecast. This forecast builds on the methodology that E3 originally developed through a stakeholder process for the Western Electricity Coordinating

[68] Non-solar technology costs are also examined and presented later in this section.
[69] See http://ny-sun.ny.gov/for-installers/megawatt-block-incentive-structure

Council (WECC) in December 2013.[70] Generally speaking, a "learning curve" methodology is used to forecast future solar PV installed costs, which is applied to the current average solar PV pricing for each utility. Learning curves are used to describe an observed empirical relationship between installed solar PV capacity and solar PV costs. The learning curve depends on a learning rate that defines the expected decrease in costs with every doubling of "experience," e.g. solar PV installed capacity. The figure below shows an example of a learning curve.

Figure 38: Example 20% Learning Curve



The Untargeted NEM and Targeted NEM scenarios in this analysis assume a 15% learning rate for PV non-module hard costs and a 20% learning rate for "soft" costs, which include permitting or customer acquisition. These numbers are 10% learning rate for PV non-module hard costs and 15% for soft costs in the Low NEM Value scenario and 20%/25% in the High NEM Value scenario. The "experience" curve used for the decrease in PV non-module hard costs is from the International Energy Agency (IEA) Medium-Term Renewable Energy Market Report 2014[71] forecast of global solar PV installations. We use a worldwide forecast given that PV modules tend to operate in a worldwide market. For a 15% learning rate this means when the global installation level doubles, PV non-module hard costs drop by 15%. To forecast the decline in

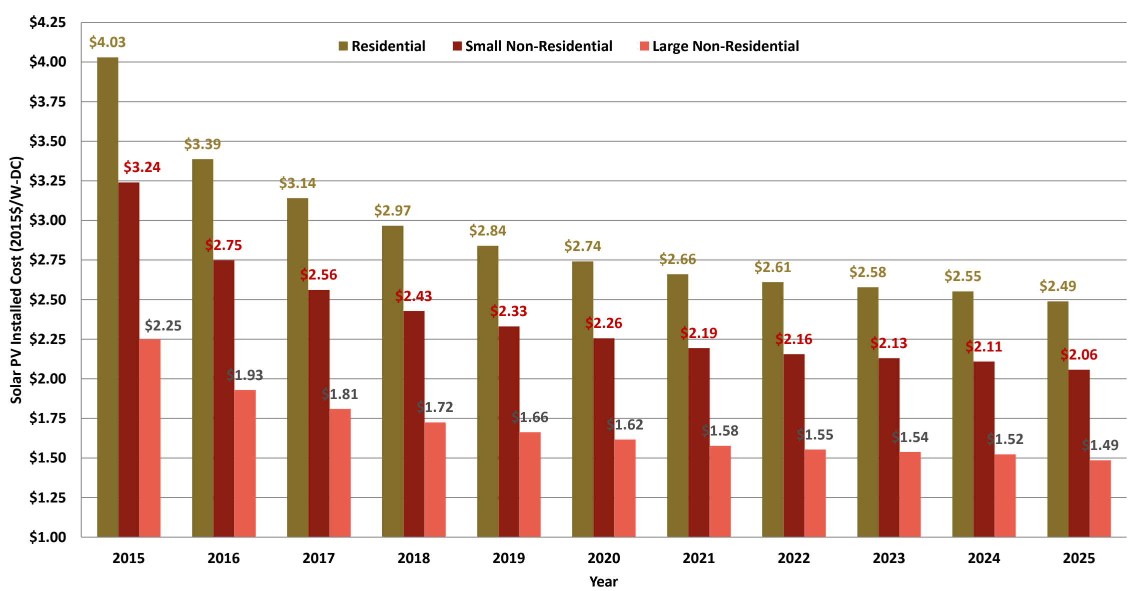
[70] E3's 2014 capital cost report and capital cost pro forma model are available for download on the WECC website: **http://www.wecc.biz/committees/BOD/TEPPC/Pages/2015_Plans.aspx**

[71] http://www.iea.org/Textbase/npsum/MTrenew2014SUM.pdf

"soft" costs, which tend to be driven more by locally rather than worldwide experience, a "local" or New York specific solar PV forecast is used as the experience curve. This local forecast is the one used throughout this analysis, the 3.29 GW-DC MW Block program target by 2025.

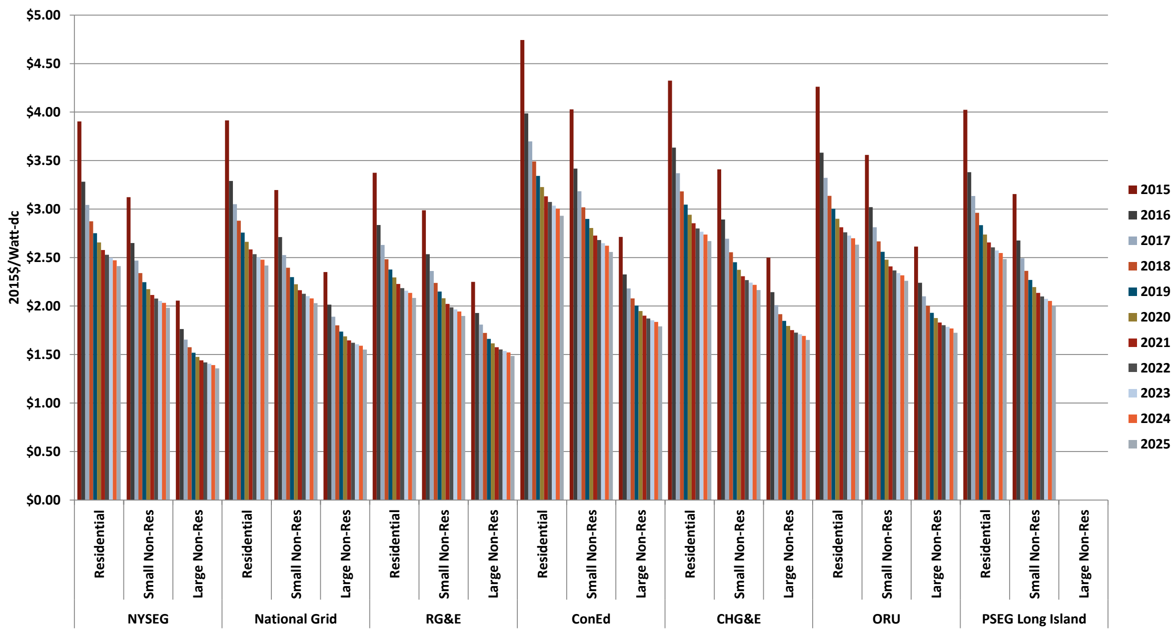
The figure below shows the 2015 to 2025 PV costs used in the analysis. The 2015 value represents the average current New York state costs as reported in the NY-Sun installation database. The projected prices from 2016 through 2025 show a decline in solar PV prices as the local learning applied to soft costs leads to marked cost reductions. Note these projections remain well-within U.S. Department of Energy forecasts.[72]

Figure 39: New York State Forecast Solar PV Costs



[72] U.S. Department of Energy Sunshot Initiative: *PV Pricing Trends: Historical, Recent, and Near-Term Pricing Trends.* Available at: http://www.nrel.gov/docs/fy14osti/62558.pdf

Figure 40: Detailed Solar PV Cost Forecast by Utility and Class



1.10.1.1 Detailed Solar PV Cost Forecast Methodology

The cost of solar photovoltaic installations is expected to continue its long-term downward trend. Reductions in capital costs may be achieved through a number of pathways including both hardware ("hard") costs and the remaining balance of system ("soft") costs. To capture the different cost reduction opportunities, E3 has broken capital costs out into three categories for each class of solar PV being examined in this analysis (i.e. residential, small non-residential (up to 200 kW), and large non-residential (>200 kW up to 2 MW)):

+ **Module costs:** direct cost of photovoltaic modules
+ **Non-module "hard" costs:** costs of inverter, racking, electrical equipment, etc.
+ **"Soft" costs:** labor, permitting fees, customer acquisition costs, etc.

To project the plausible magnitude of these future cost reductions, E3 developed learning curves for both "hard" and "soft" non-module balance-of-systems (BOS) components of the solar PV installation.

Historically, module prices have followed a learning rate of approximately 20% over the long term. This learning rate has been confirmed in many studies over varying time horizons. However, module prices are currently below this long-term learning curve due to a variety of reasons such as current supply/demand imbalances, temporary price declines in silicon, and other idiosyncratic factors. Therefore this study keeps the current observed module price constant in real terms until the long term learning curve "catches up" to the observed module price. This reflects the lowered potential for cost reductions in the near to medium term due to the aforementioned factors. E3 believes this is reasonable longer-term forecast, and anecdotal evidence such as module price forecasts further support that prices will remain flat in the near to medium term. The figures below show how the methodology for solar PV modules approaches the long-term trend as global installed capacity increases.

Figure 41: Solar PV Module Cost Learning Curve

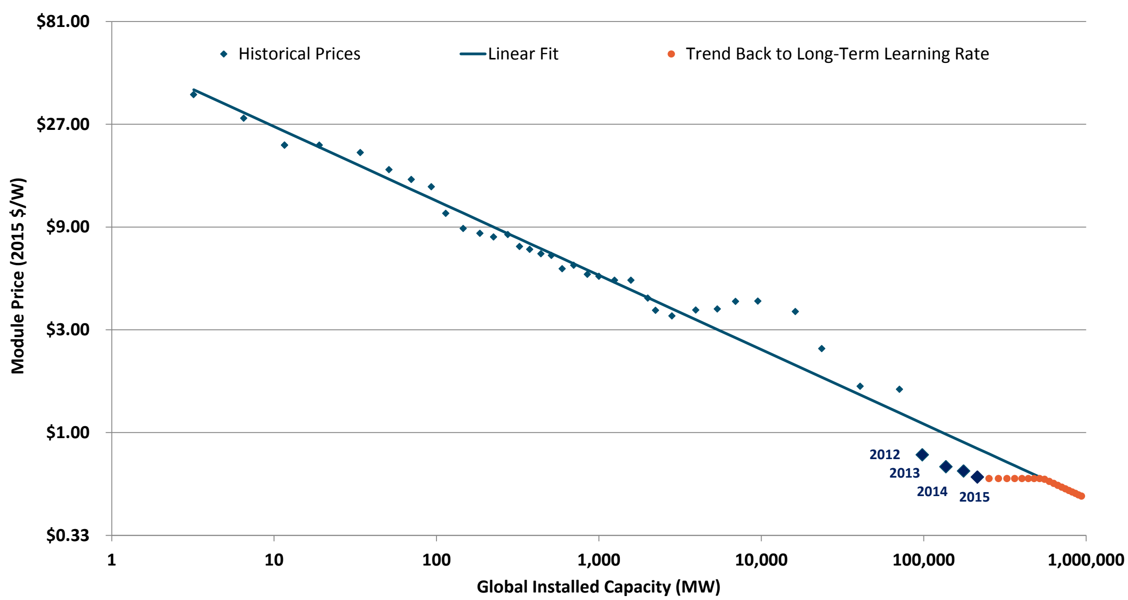
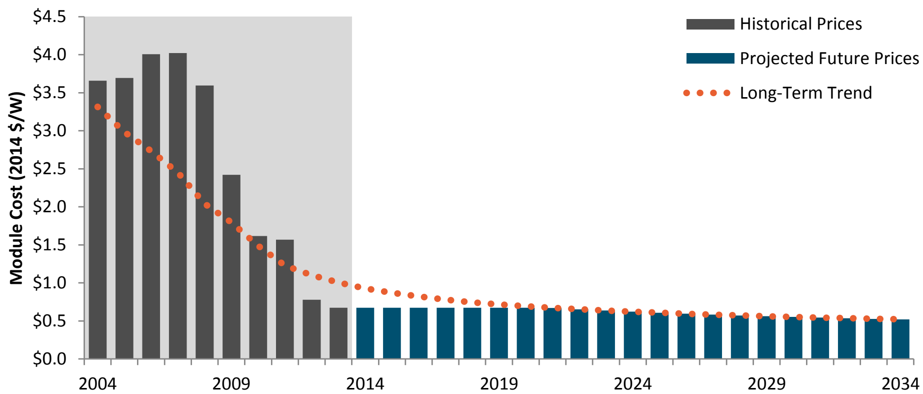
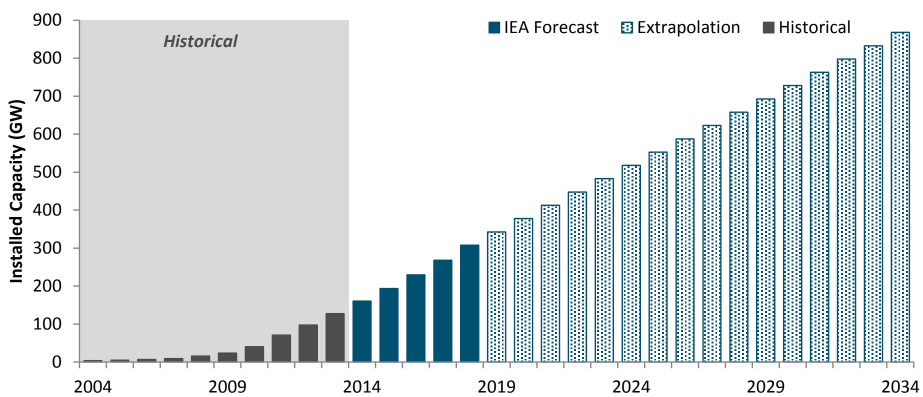


Figure 42: Historic and Projected Solar PV Module Prices Based on Observed Learning Curve



For a forecast of global installed capacity to use when calculating learning curves for hardware costs, E3 relied on the IEA's Medium-Term Renewable Energy Market Report 2014, which forecasts global installed capacity from 2015 through 2019. This forecast is then extrapolated through 2025 assuming a continued rate of installations based on the change in global installed capacity over the original forecast period (2015-2019). The resulting forecast is shown below.

Figure 43: Forecast of Global Installed Solar PV Capacity Used to Evaluate PV "Hard" Cost Reductions through Application of Learning Curves



There has been considerably less focus on historical learning rates for balance-of-system or non-module components. The range of estimates is considerably larger: the International Energy Agency (IEA) has had learning rates of 18% for BOS, a recent LBNL study found that BOS costs for systems installed between 2001 and 2012 in the U.S. followed a learning rate of 7%, and in Germany the historical BOS learning rate has been 15%.[73] While there are substantial opportunities to reduce non-module BOS costs through expedited permitting and installation processes, which are NY-Sun program goals, these costs may not naturally decline along the same 20% learning curve as the historical module-related costs. Additionally, some of these BOS cost savings may have already occurred in the larger scale solar PV system given the incentives and cost/benefits of said savings in those segments.

E3 uses a 15% learning rate for all classes of solar PV installation in New York for “hard” non-module BOS-related costs and a 20% learning rate for soft costs in the Untargeted NEM and Targeted NEM scenarios.[74] This reflects the fact that there has been substantial recent effort to identify cost reduction potential in smaller distributed solar PV systems such as the types being incented and built per the MW Block program. For example, some of these efforts include reducing permitting and customer acquisition costs which can make up a significant portion of the installed cost of solar PV. E3 uses the worldwide IEA forecast of installed solar PV to forecast non-module “hard” cost reductions as, like modules, they are influenced by learning on a worldwide basis. However, for the non-module “soft” costs the linear forecast of installations was used based on the NYISO forecast of distributed solar PV installations 2.7 GW-AC from 2015 to 2025)[75]. The figure below shows the forecast of solar PV installations as a result of the MW Block program that the 15% learning curve is applied against to forecast price declines in that portion of the current solar PV cost.

[73] http://www.nrel.gov/docs/fy14osti/60412.pdf

[74] These values are 15% soft/10% hard and 25%/20% for the Low NEM Value and High NEM Value scenarios, respectively

[75] **http://www.nyiso.com/public/webdocs/markets_operations/services/planning/Documents_and_Resources/Planning_Data_and_Reference_Docs/Data_and_Reference_Docs/2015%20Load%20and%20Capacity%20Data%20Report.pdf**

Figure 44: Projected Residential Cost Reductions for Solar PV Based on Learning Curves Applied to the IEA Worldwide Forecast for Non-Module "Hard" Costs and the E3 New York Forecast for Non-Module "Soft" Costs

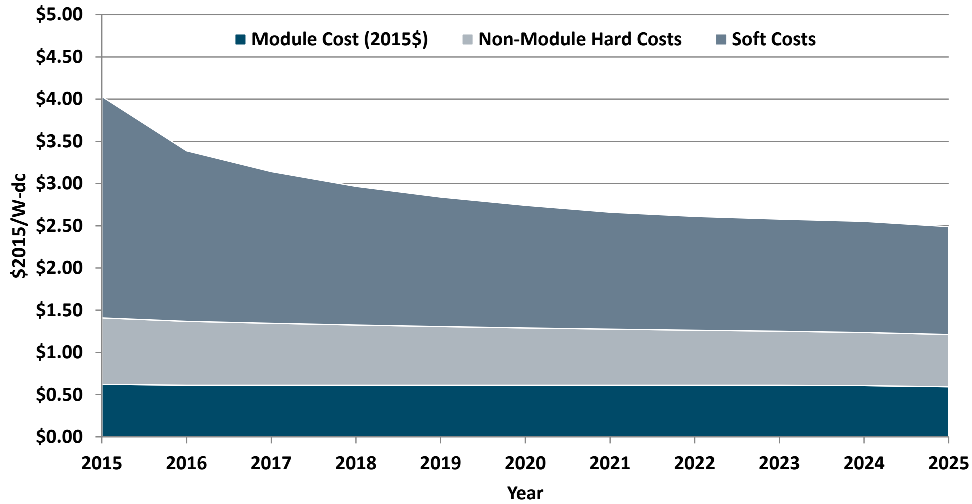


Figure 45: Projected Small Non-Residential Cost Reductions for Solar PV Based on Learning Curves Applied to the IEA Worldwide Forecast for Non-Module "Hard" Costs and the E3 New York Forecast for Non-Module "Soft" Costs

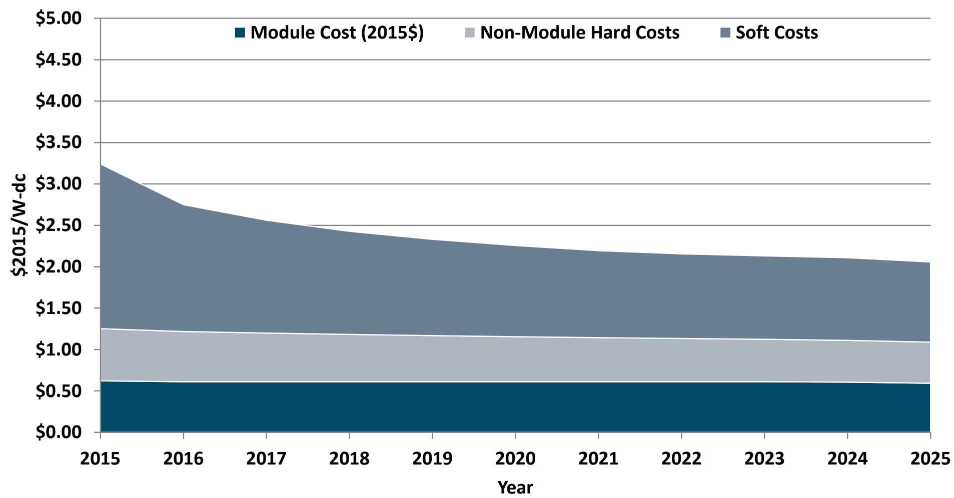
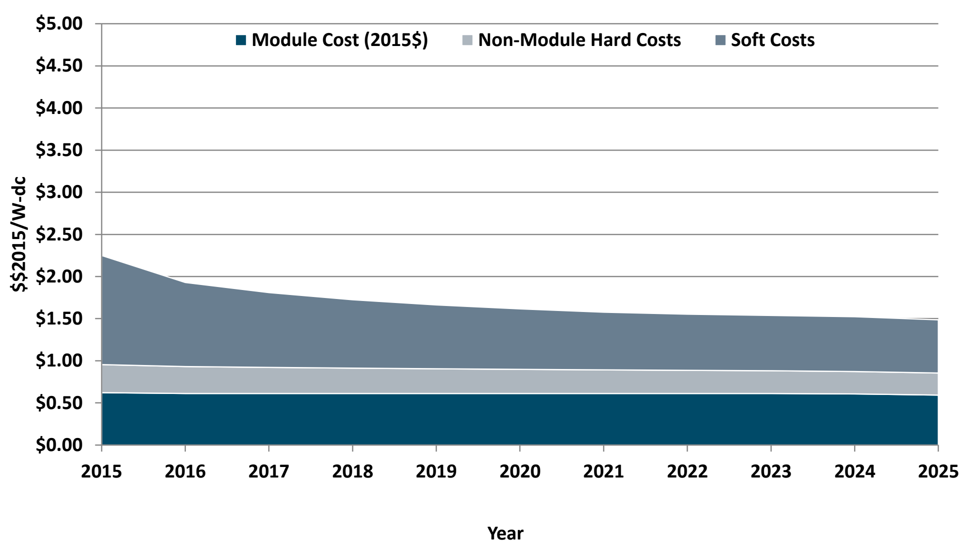
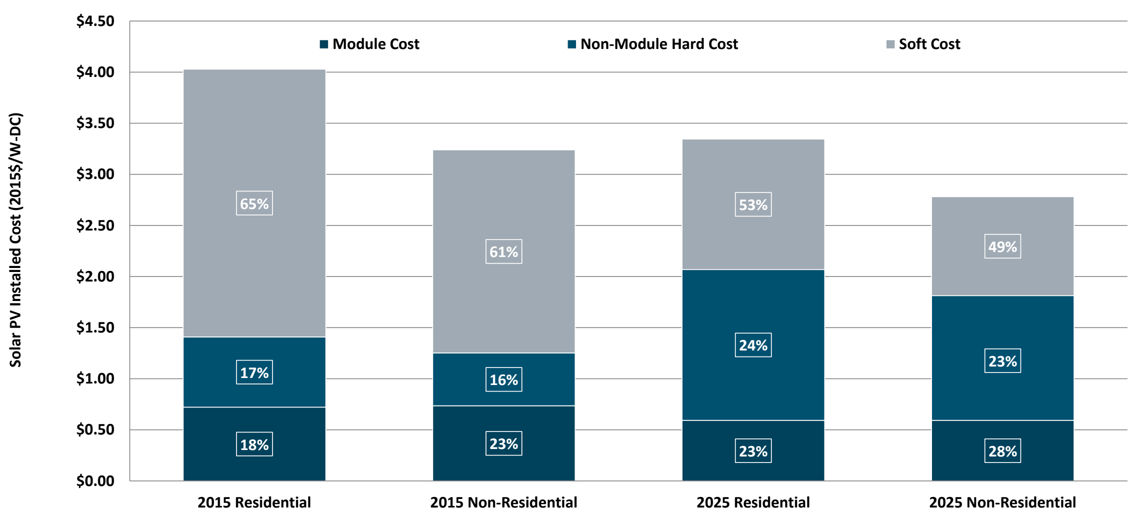


Figure 46: Projected Large Non-Residential Cost Reductions for Solar PV Based on Learning Curves Applied to the IEA Worldwide Forecast for Non-Module "Hard" Costs and the E3 New York Forecast for Non-Module "Soft" Costs



To combine the three learning curves—one for module-related costs and the other two for non-module "soft" and "hard" BOS components—E3 made assumptions on the proportion of today's installed system costs that can be attributed to each. Based on several recent studies published by the National Renewable Energy Laboratories (NREL) and the Lawrence Berkeley National Lab (LBNL) along with GreenTech Media (GTM) forecasts[76], estimates of the magnitude of each of these cost categories for the solar PV resources in New York were developed. The figure below graphically breaks down these categories on a percentage basis as compared to the current cost of solar PV in New York as well as the projected cost in 2025.

Figure 47: Estimated Breakdown of Module and Non-Module "Soft" and "Hard" Costs by Customer Class in 2015 and 2025



Weighting the three individual learning curves by these fractions, the module- and non-module BOS-related cost projections are joined to create a single projection of system costs over the next ten years, as shown below. The approach described above results in significant reductions in solar PV capital costs in real terms in New York relative to 2015 levels by 2025 as follows:

+ Residential: 38% reduction

[76] http://mdvseia.org/wp-content/uploads/2015/05/US-SMI-Q2-2014-Full-Report.pdf

- Small non-residential: 36% reduction
- Large non-residential: 34% reduction

1.10.2 CAPITAL COST SENSITIVITIES

For the purposes of creating the high and low scenarios examined below in this report E3 looked at varying our learning rates to see the effects on the capital cost forecast, using a 15% and 10% learning rate applied to both the soft and hard non-module costs respectively for the Low NEM Value scenario as well as a 25% and 20% rate for the High NEM Value scenario. See the figures below for the statewide solar cost forecasts under these two sensitivities.

Figure 48: Long-Term % Decline in Solar PV Costs Using a 15% Soft Cost and 10% Non-Module Hard Cost Learning Rate

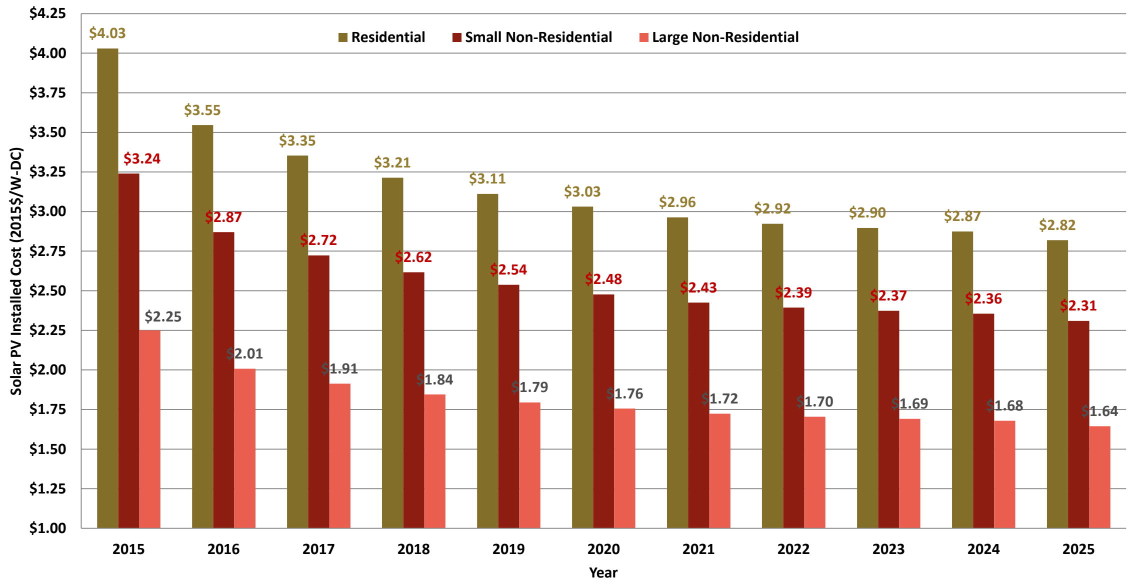
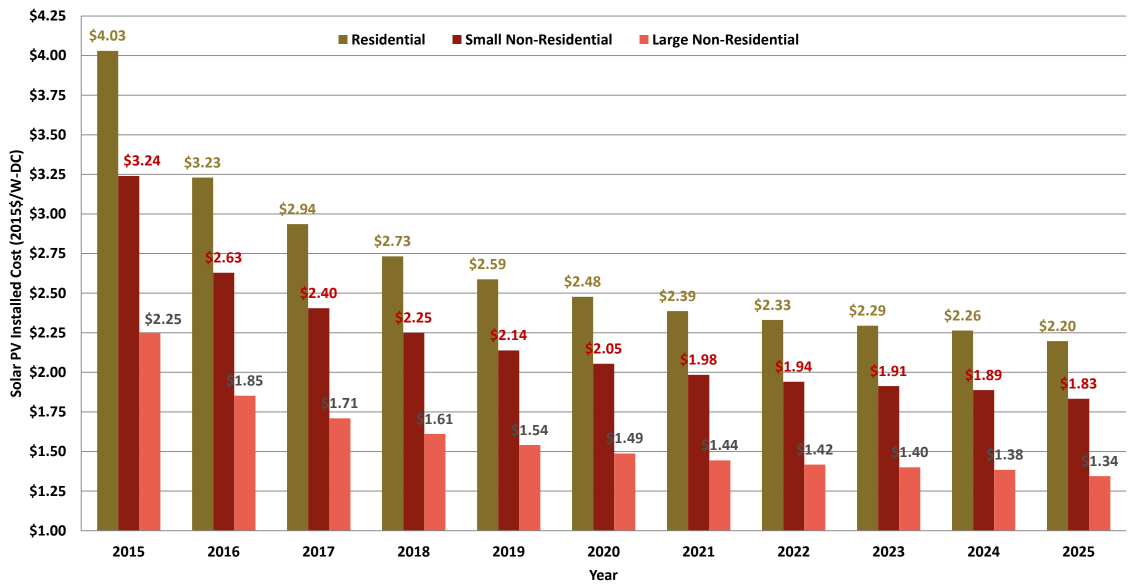


Figure 49: Long-Term % Decline in Solar PV Costs Using a 25% Soft Cost and 20% Non-Module Hard Cost Learning Rate



1.10.3 OPERATIONS AND MAINTENANCE COSTS

E3 approximated O&M costs from the NREL estimate of solar PV renewable energy costs.[77] A fixed O&M cost of $15/kW-year is assumed for all solar PV installations in New York.

1.10.4 FEDERAL TAX CREDITS

The predominant federal tax credit that solar PV systems qualify for is the investment tax credit (ITC). The ITC began in 2006 for customer-sited solar generators and its credit value is 30% of eligible installed system capital costs through the end of 2016, when it drops to 10%. E3 assumes that third party system owners are always able to fully access the ITC tax benefits over the analysis time frame.

1.10.5 STATE TAX CREDITS

New York's Residential Personal Solar Tax Credit[78] is modeled in this initial analysis. The Residential Personal Solar Tax Credit is 25% of the cost of equipment and installation for all PV systems. Third party owned systems receive this credit as a percentage of the lease or PPA payments made during the taxable year for up to 15 years. The maximum allowable tax credit for a system is $5,000.

To model this tax credit, all systems are assumed to be third party owned. The amount of the tax credit is then 25% of annual PPA payments for up to 15 years and a cap of $5,000, whichever is reached first. The Residential Personal Solar Tax Credit is applied only to residential PV systems. This tax credit, like the MW Block Incentive, is assumed to be taxable and result in an increase in federal taxes paid.

[77] NREL O&M cost estimates are available at: http://www.nrel.gov/analysis/tech_lcoe_re_cost_est.html
[78] http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=NY03F&re=1&ee=1

1.10.6 PROPERTY TAXES

New York State currently has two laws enabling property tax exemptions for solar PV systems. The first is Section 487 of the New York State Real Property Tax Law,[79] which provides a 15-year real property tax exemption for solar, wind, and farm-waste energy systems in New York. The law is a local option exemption, meaning local governments have jurisdiction over deciding whether the law applies or not in their territory. The second law[80] is applicable to New York City only,[81] and allows building owners to deduct a portion of PV installation costs from their real property taxes, up to a cap of $62,500 annually. The total property tax benefit can be either 35%, 20%, or 10% of installed system cost; the amount depends on installation year.

As a simplifying assumption for this initial analysis E3 set all property taxes equal to 0% for solar PV systems installed in New York.

1.10.7 COST OF CAPITAL

For this analysis E3 interpolated forward interest rates from the July 30, 2015 U.S. Treasury Yield Curve for an assumed 18-year project debt term. The interpolation used 6.0% as the current cost for solar PV project debt. Based on the Yield Curve the cost for solar PV project debt increases to approximately 6.62% by 2025. An 8.25% weighted average cost of capital (WACC) is assumed from 2015-2016 and 8.5% from 2017-2025. The WACC represents the costs of both debt and equity weighted by the capital structure of the project. In this analysis E3 assumed that the project's share of equity for each class and utility in each year (2015-2025) is optimized so that there is sufficient project cash flow to meet a 1.4x debt service coverage ratio (DSCR), i.e. operating cash flow from solar PV system = 1.4x annual debt payments. This DSCR value represents a standard assumption on the level of debt financing a project can raise.

[79] http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=NY07F&re=1&ee=1
[80] http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=NY52F&re=1&ee=1
[81] The law technically applies to any city with a population of 1 million or more people in the state of New York, but this currently means only New York City.

1.10.8 MW BLOCK INCENTIVES

The incentive a given system receives through the NY-Sun MW Block program is determined as a function of utility (region) installation forecast on an annual average basis. E3 received a base installation forecast from NYSERDA, and combined this with information from NYSERDA's PowerClerk Megawatt Block Incentive Dashboard on current utilization of block incentives as of July 21, 2015.[82] The information on current installations allowed E3 to calculate an installation rate for each region and class (e.g. Upstate Residential) over the lifetime of the incentive to date.[83] E3 then used the NYSERDA future installation forecast to calculate a rate at which remaining incentives for each region and class would be used up in subsequent years. The result of this methodology is that regions and classes with higher install rates see their incentives close sooner than those which slower install rates. This also means the amount of behind the meter solar forecast to be installed from 2014-2025 does not exactly match the 3.29GW-DC block, but is instead based on this block with modifications for current installation rates that may lead to blocks closing prior to the 2023 program end date.

In the case of a region and class where not all incentives are used by 2023, the incentive level is assumed to drop to zero in 2024 even though incentives remain. Finally, for each year E3 takes a weighted average of the incentive received by forecast installations in that region and class for that year to calculate an average annual incentive to input into the pro forma.[84]

In the case of Small Non-Residential systems, the MW block program provides different incentive levels for the first 50 kW of a system and the next 150 kW. E3 assumes the standard Small Non-Residential system is 75 kW, so these systems receive two-thirds of their incentive at the higher first 50 kW rate and the rest at the lower 150 kW rate. Large Non-Residential incentive levels are calculated in the same manner for a 1 MW system size, but are paid out 30% up-front and 70% as a performance based incentive (PBI) set to a user-specified duration of

[82] http://ny-sun.ny.gov/For-Installers/Megawatt-Block-Incentive-Dashboard
[83] since 1/1/2014 except for Large Non-Residential, which began 5/4/2015
[84] So, for example, if 25% of systems received $.30/W while 75% received $.20/W in a given year, the incentive received by a system in that year in the pro forma is $.225/W.

years (base case assumption is 3 year PBI, and assumes systems receive the full incentive by reaching their forecast production level). Residential and small non-residential systems are paid out entirely as an up-front incentive. All MW Block Incentives are assumed to be taxable income.

1.10.9 SYSTEM COST *PRO FORMA*

The *pro forma* financial model calculates the nominal levelized NEM system capital and O&M costs, including all incentives. The financial calculations assume all systems are owned by third parties and financed with PPAs, where the PPA price the customer pays is equal to the net system costs levelized over the PPA contract length.

The table below shows our active financing cost assumptions. The New York NEM Pro Forma Financial Calculator model optimizes debt and equity shares in order to reach the target 1.4x DSCR. Debt costs are based on an assumption of 6.0% debt costs in 2015 escalated in subsequent years at a rate equivalent to the implied forward rate based on the imputed 18 Year Treasury Debt Yield curve and the assumed cost of capital.

Figure 50: WACC and Cost of Debt Assumptions

	After Tax WACC	Cost of Debt
2015	8.250%	6.124%
2016	8.250%	6.216%
2017	8.500%	6.286%
2018	8.500%	6.330%
2019	8.500%	6.373%
2020	8.500%	6.401%
2021	8.500%	6.448%
2022	8.500%	6.491%
2023	8.500%	6.528%
2024	8.500%	6.577%
2025	8.500%	6.624%

The table below lists other key financing input assumptions to the pro forma model. These inputs apply to all system types modeled, unless otherwise specified. Of note, inflation is set to 2%/yr. for the purposes of converting all results into nominal dollars.

Figure 51: Additional Financing Inputs

Input	Value
Inflation	2%/yr.
MACRS Depreciation Term	5 years[85]
Federal Income Tax	35%
State Income Tax	6.5%[86]
Property Tax	0%[87]
Insurance Cost	0.5% of CapEx
O&M Cost Escalation	2%/year
PPA Term	20 years
ITC Step-down	10% from 2017 on
State Residential Personal Tax Incentive	25%
Maximum Residential System Size for Receiving MW Block Incentive	25 kW
Maximum Small No-Residential System Size for Receiving MW Block Incentive	200 kW
PBI Term for Large Non-Residential Systems	3 years

The table below provides a summary of the capacity factors E3 uses in the model. Our bill and avoided cost calculations use hourly generation profiles in order to capture the importance of differences in renewable generation shapes. In the pro forma model, we used simplified representative capacity factors for each technology type and utility to calculate levelized costs.

[85] Department of the Treasury Internal Revenue Services Publication 946, available at: http://www.irs.gov/pub/irs-pdf/p946.pdf
[86] See http://taxfoundation.org/article/new-york-corporate-tax-overhaul-broadens-bases-lowers-rates-and-reduces-complexity for current updates to New York State corporate income tax rate.
[87] Simplifying assumption based on current New York property tax exemptions for solar systems. See http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=NY07F&re=1&ee=1 and http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=NY52F&re=1&ee=1.

Figure 52: Capacity Factor Assumptions

	Capacity Factor (DC)	Annual kWh/kW-dc
NYSEG	13.59%	1190.5
National Grid	13.26%	1161.6
RG&E	14.06%	1231.7
ConEd	12.99%	1137.9
CHG&E	13.11%	1148.5
ORU	13.12%	1149.3
LIPA	13.27%	1162.45

The Residential Personal Solar Tax Credit and MW Block Incentive are included in the calculation. All systems take full advantage of the federal ITC (30% tax credit through 2016, 10% thereafter). State tax credits and state (MW Block) incentives are assumed to be subject to federal and state taxes, while the ITC is a full offset of tax liability.

These values are used in the financial pro forma tool to calculate a nominal levelized cost of energy including all incentives and taxes for each combination of utility (LIPA, ConEd, CHG&E, RG&E, National Grid, NYSEG, ORU), year (2015-2025), and customer class (residential, small non-residential, large non-residential). As noted previously, system sizes are fixed for each customer class (4 kW residential, 75 kW small non-residential, 1000 kW large non-residential). $/kW-year values are also calculated and used in our initial analysis.

1.10.10 NON-SOLAR TECHNOLOGIES

In addition to all the inputs and specifications used to model behind the meter solar PV installations from 2015-2025 in New York, E3's pro forma provides an option to look at representative distributed wind, small hydro, residential combined heat and power (CHP), and biogas-fired anaerobic digester gas (ADG) generators. Because installations of these technologies are expected to be small relative to solar and site-specific, E3 models only representative systems and does so without any installation forecast or associated 'real' reductions in installation cost. Some differences between these technologies and the solar systems modeled as well as input assumptions for these technologies are listed below.

	Technology			
Metric	Wind	Small Hydro	CHP	ADG
Capital Cost ($/kW)	$7,860 (Residential), $5,310 (Commercial and Industrial)	$5,000	$6,000 (Residential), $3,500 (Commercial), $2,500 (Industrial)[88]	$10,000 (Residential), $6,000 (Commercial), $5,000 (Industrial)
Fixed O&M ($/kW-yr.)[89]	$30	$30	$15	$15
Capacity Factor (%)	~15% (varies by utility geography)	89.65%[90]	40.43%[91]	90%
Variable O&M ($/MWh)			$40	$40
Fuel ($/mmBtu)			$12.50	$25
MACRS Term (years)	5	5	5	5
Heat Rate (Btu/kWh)			15,000	10,000
Property Tax (%)	0%	0%	0%	0%

Unless otherwise noted above in footnotes, inputs reflect E3's estimate for this representative system. All of these NEM eligible technologies are not currently nor projected in the future to be installed in meaningful quantities in New York. Therefore, all inputs are only an estimate. In fact, as resource (e.g. river for small hydro, amount of waste heat for CHP) can vary greatly by customer and would affect the decision to install, actual cost-effectiveness of these technologies for an individual system could vary greatly from the representative numbers calculated by E3.

Other differences between these technologies and solar PV include that they have no MW block incentives, and CHP is assumed to be gas fired and does not receive carbon benefits. Other basic assumptions about the Residential Tax Credit, ITC level, third party financing, and pro forma calculation methodology remain the same.

[88] Due to New York net metering rules only residential CHP systems up to 10 kW can be net metered, so as a practical matter larger systems are unlikely to be installed.
[89] Based on E3's California net metering and WECC capital cost work.
[90] Based on annual hydro generation by month for small (<10,000 MWh/yr.) hydro facilities in the state of New York. Months with lower generation are assumed to have either lower production or higher chance of outage for the small hydro turbine.
[91] Based on TMY weather data where hours forecast for temperatures above 55 degrees in New York City are expected to not require enough heating to justify running the CHP system.

1.11 Detailed Scenario Inputs

The following are the detailed changes in assumptions and benefit-cost components that are varied across the four NEM scenarios examined in this analysis.

Scenarios	Lower NEM Value	Untargeted NEM (Business as Usual)	Targeted NEM	Higher NEM Value
Solar PV Block Size	500 MW	500 MW	500 MW	500 MW
Energy (No Carbon)	-10% of BAU	NYISO CARIS Shaped Hourly with Historical LBMPs (Net of NYISO CARIS Carbon Forecast)	NYISO CARIS Shaped Hourly with Historical LBMPs (Net of NYISO CARIS Carbon Forecast)	+10% of BAU
Monetized Carbon Costs	-15% of BAU	NYISO CARIS Carbon Forecast	NYISO CARIS Carbon Forecast	+15% of BAU
Losses	Loss Factors x Energy	Loss Factors x Energy	Loss Factors x Energy	Loss Factors x Energy
Ancillary Services	1% of Energy Costs (Most ancillaries procured by NYISO on a fixed basis like spinning reserves)	1% of Energy Costs (Most ancillaries procured by NYISO on a fixed basis like spinning reserves)	1% of Energy Costs (Most ancillaries procured by NYISO on a fixed basis like spinning reserves)	1% of Energy Costs (Most ancillaries procured by NYISO on a fixed basis like spinning reserves)
Reactive Power	De minimis	De minimis	De minimis	De minimis
System Capacity	2.5% Reduction in Peak Load after 2017 in DPS BCA ICAP Model	DPS BCA ICAP Model BAU Output	DPS BCA ICAP Model BAU Output	2.5% Decrease in Generation Supply after 2017 in DPS BCA ICAP Model
System (NYCA) Peak Demand Reduction Realization Rate (%) by NEM Production	10% Decrease in BAU Coincidence	Realization Rate Based on Coincidence between NEM production and NYCA System Load (Peak Capacity Allocation Factors)	Realization Rate Based on Coincidence between NEM production and NYCA System Load (Peak Capacity Allocation Factors)	10% Increase in BAU Realization Rate (e.g. west facing PV + storage?)
Transmission Capacity	Accounted for in LBMP and ICAP	Accounted for in LBMP and ICAP	Accounted for in LBMP and ICAP	Accounted for in LBMP and ICAP
Sub-Transmission Capacity	None	Average Values Based on Utility Specific MCOS Studies	Average Values Based on Utility Specific MCOS Studies	Average Values Based on Utility Specific MCOS Studies
Sub-Transmission (Zonal) Peak Demand Reduction Realization Rate (%) by NEM Production	None	20% of Realized Average Coincidence Factor from Targeted Solar Case	Realization Rate Based on Coincidence between NEM production and Zonal Loads (Peak Capacity Allocation Factors)	120% of Realized Average Coincidence Factor from Targeted Solar Case
Distribution Capacity	None	Average Values Based on Utility Specific MCOS Studies	Average Values Based on Utility Specific MCOS Studies	Average Values Based on Utility Specific MCOS Studies
Distribution (Substation) Peak Demand Reduction Realization Rate (%) by NEM Production	None	20% of Realized Average Coincidence Factor from Targeted Solar Case	Realization Rate based on Coincidence between NEM Production and Substation Loads (Peak Capacity Allocation Factors)	120% of Realized Average Coincidence Factor from Targeted Solar Case
Market Price Effect	None	Based on NYSIO High Solar PV case with incremental solar MWh assumed to produce $15/MWh of effect in year and then discounted by 50% to $7.50/MWh in year 2, and then $0/MWh in subsequent years	Based on NYSIO High Solar PV case with incremental solar MWh assumed to produce $15/MWh of effect in year and then discounted by 50% to $7.50/MWh in year 2, and then $0/MWh in subsequent years	Based on NYSIO High Solar PV case with incremental solar MWh assumed to produce $15/MWh of effect in year and then discounted by 50% to $7.50/MWh in year 2, and then $0/MWh in subsequent years
Resiliency/Restoration	None	None	None	None
Other	None	None	None	None
Social Cost of Carbon	5.0% Discount Rate EPA Social Cost of Carbon (Net of NYISO Forecast)	3.0% Discount Rate EPA Social Cost of Carbon (Net of NYISO Forecast)	3.0% Discount Rate EPA Social Cost of Carbon (Net of NYISO Forecast)	2.5% Discount Rate EPA Social Cost of Carbon (Net of NYISO Forecast)
Health Benefits (SO2 and Nox)	EPA Krewski SO2 and Nox Damage Values 3% Discount Rate (Net of NYISO Forecast)	EPA Midpoint SO2 and Nox Damage Values 3% Discount Rate (Net of NYISO Forecast)	EPA Midpoint SO2 and Nox Damage Values 3% Discount Rate (Net of NYISO Forecast)	EPA Lepeule SO2 and Nox Damage Values 3% Discount Rate (Net of NYISO Forecast)
CO2, SO2, and Nox Emission Rates	5% Decrease from BAU	EPA eGRID Annual Emission Data for NY Generating Units and NYISO 2014 State of the Market Marginal Fuel Analysis	EPA eGRID Annual Emission Data for NY Generating Units and NYISO 2014 State of the Market Marginal Fuel Analysis	5% Increase from BAU
Integration Costs	$3/MWh	$2/MWh	$2/MWh	$1/MWh
Program Costs	$3/MWh	$2/MWh	$2/MWh	$1/MWh
NEM Capital Costs	15/10% Soft/Hard Cost Real Learning Rates for Solar PV and No Change for Non-Solar Technologies	20/15% Soft/Hard Cost Real Learning Rates for Solar PV and Lazard #s in constant real terms for Non-Solar Technologies	20/15% Soft/Hard Cost Real Learning Rates for Solar PV and Lazard #s in constant real terms for Non-Solar Technologies	25/20% Soft/Hard Cost Real Learning Rates for Solar PV and 10% Real Decrease for Non-Solar Technologies
T&D Retail Rate	+10% from BAU	T&D Rates (CPR Rate Tool) escalated at AEO T&D Forecast + Forecast Energy/Capacity Supply Charge Growth Rate	T&D Rates (CPR Rate Tool) escalated at AEO T&D Forecast + Forecast Energy/Capacity Supply Charge Growth Rate	-10% from BAU

1.12 Detailed Results by Utility

Figure 53: Levelized Costs and Benefits, Central Hudson, Residential Class, Untargeted NEM Scenario, 2015 Vintage, Solar PV

	PCT	RIM	SCT
Benefit-Cost Ratio	1.09	0.53	0.80

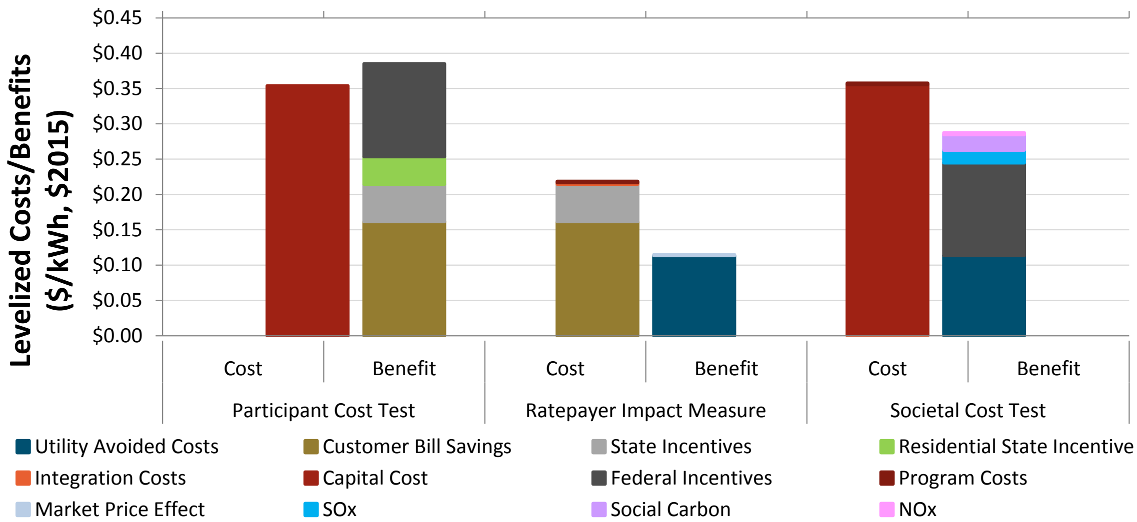


Figure 54: Levelized Costs and Benefits, Central Hudson, Non-Residential Class, Untargeted NEM Scenario, 2015 Vintage, Solar PV

	PCT	RIM	SCT
Benefit-Cost Ratio	0.99	0.78	1.02

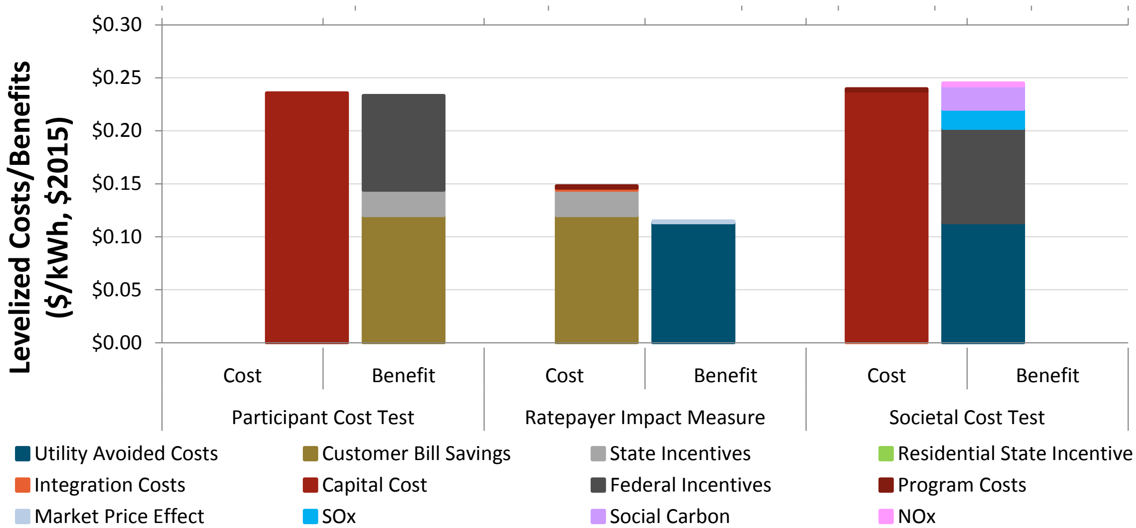


Figure 55: Levelized Costs and Benefits, Consolidated Edison, Residential Class, Untargeted NEM Scenario, 2015 Vintage, Solar PV

	PCT	RIM	SCT
Benefit-Cost Ratio	**1.27**	**0.41**	**0.80**

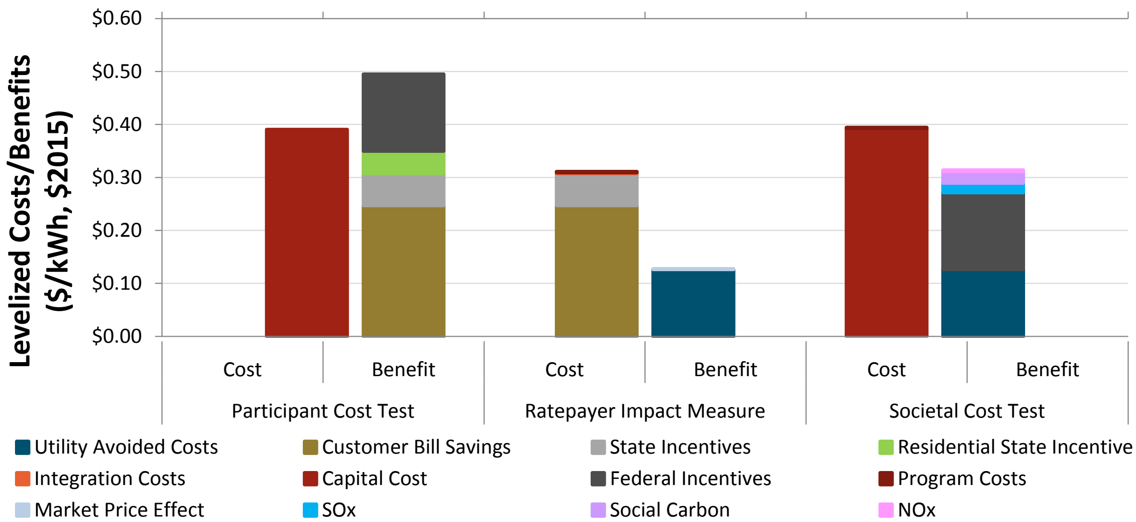


Figure 56: Levelized Costs and Benefits, Consolidated Edison, Non-Residential Class, Untargeted NEM Scenario, 2015 Vintage, Solar PV

	PCT	RIM	SCT
Benefit-Cost Ratio	1.19	0.56	0.97

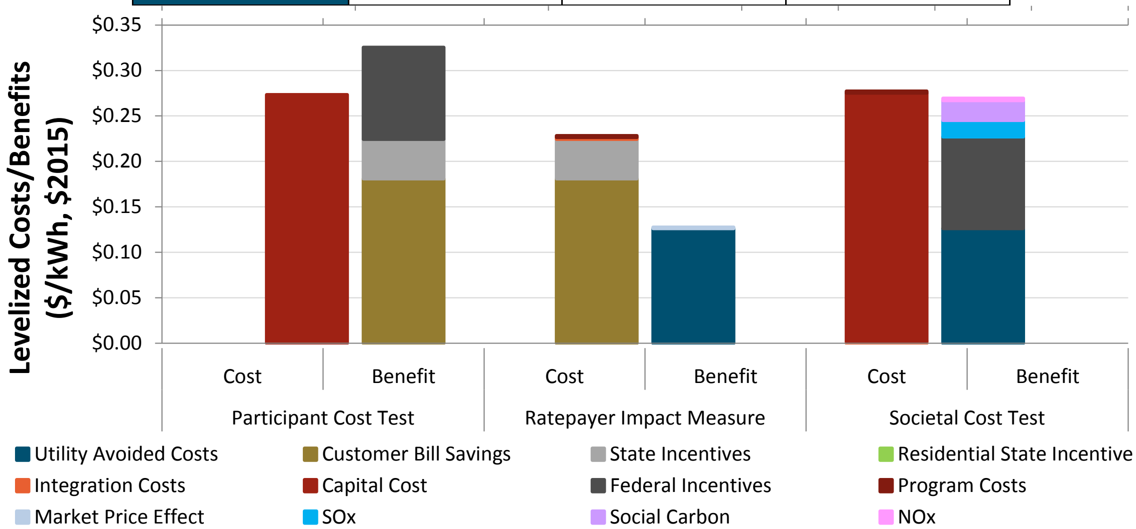


Figure 57: Levelized Costs and Benefits, NYSEG, Residential Class, Untargeted NEM Scenario, 2015 Vintage, Solar PV

	PCT	RIM	SCT
Benefit-Cost Ratio	1.13	0.49	0.82

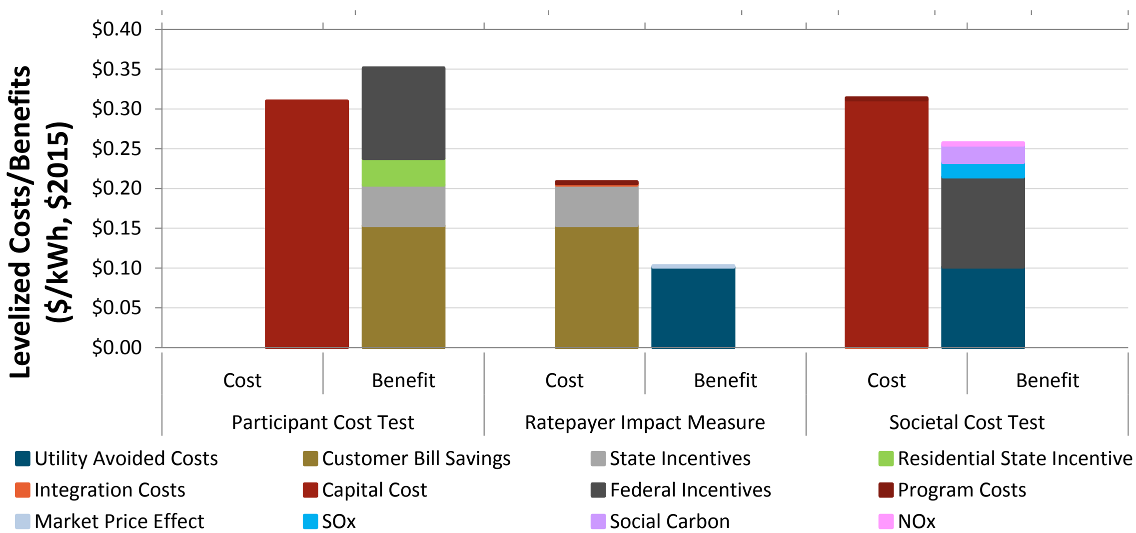


Figure 58: Levelized Costs and Benefits, NYSEG, Non-Residential Class, Untargeted NEM Scenario, 2015 Vintage, Solar PV

	PCT	RIM	SCT
Benefit-Cost Ratio	1.06	0.79	1.13

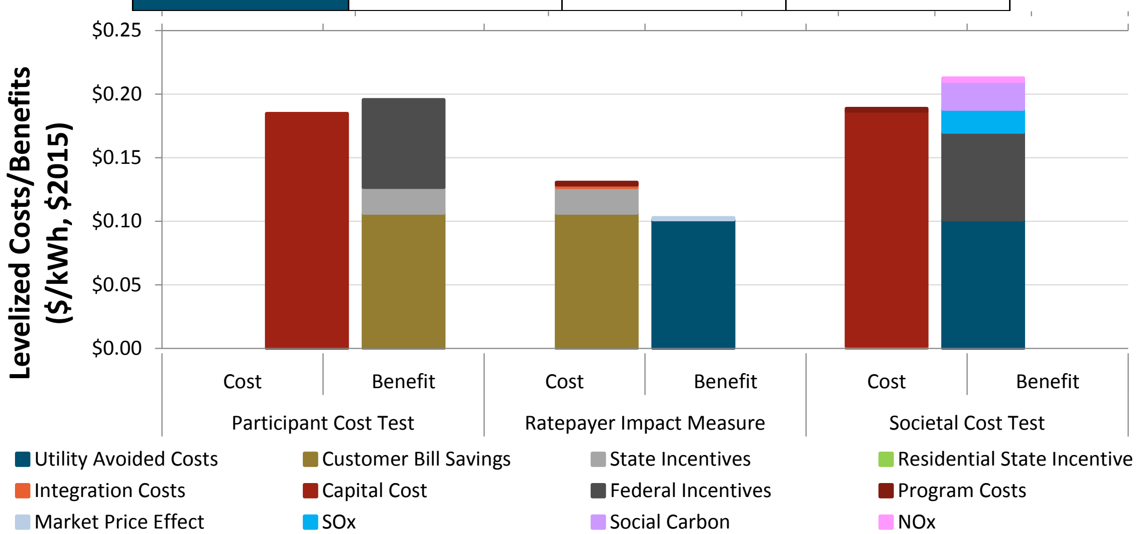


Figure 59: Levelized Costs and Benefits, National Grid, Residential Class, Untargeted NEM Scenario, 2015 Vintage, Solar PV

	PCT	RIM	SCT
Benefit-Cost Ratio	1.06	0.50	0.78

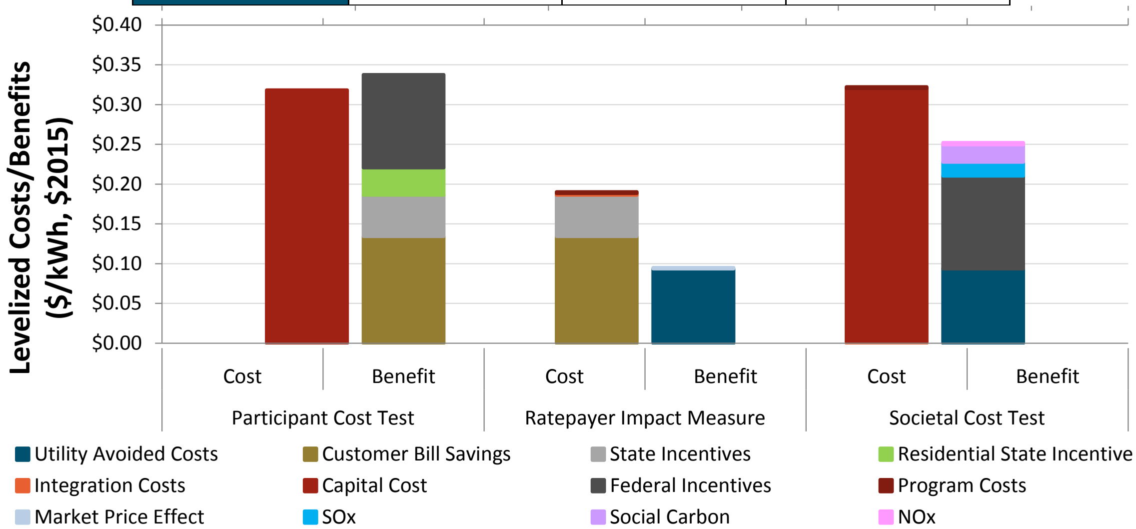


Figure 60: Levelized Costs and Benefits, National Grid, Non-Residential Class, Untargeted NEM Scenario, 2015 Vintage, Solar PV

	PCT	RIM	SCT
Benefit-Cost Ratio	0.97	0.75	1.01

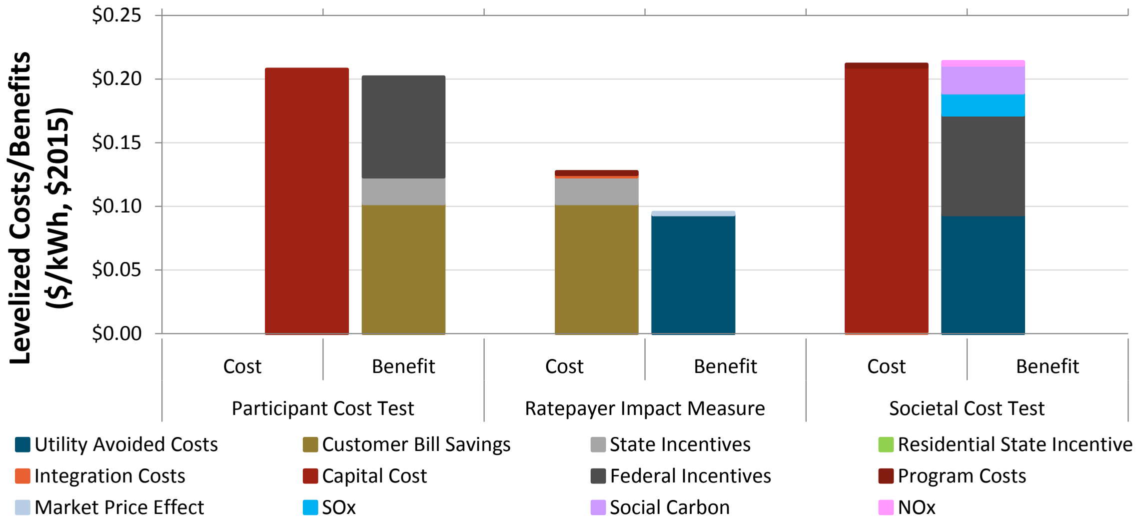


Figure 61: Levelized Costs and Benefits, RG&E, Residential Class, Untargeted NEM Scenario, 2015 Vintage, Solar PV

	PCT	RIM	SCT
Benefit-Cost Ratio	**1.15**	**0.50**	**0.85**

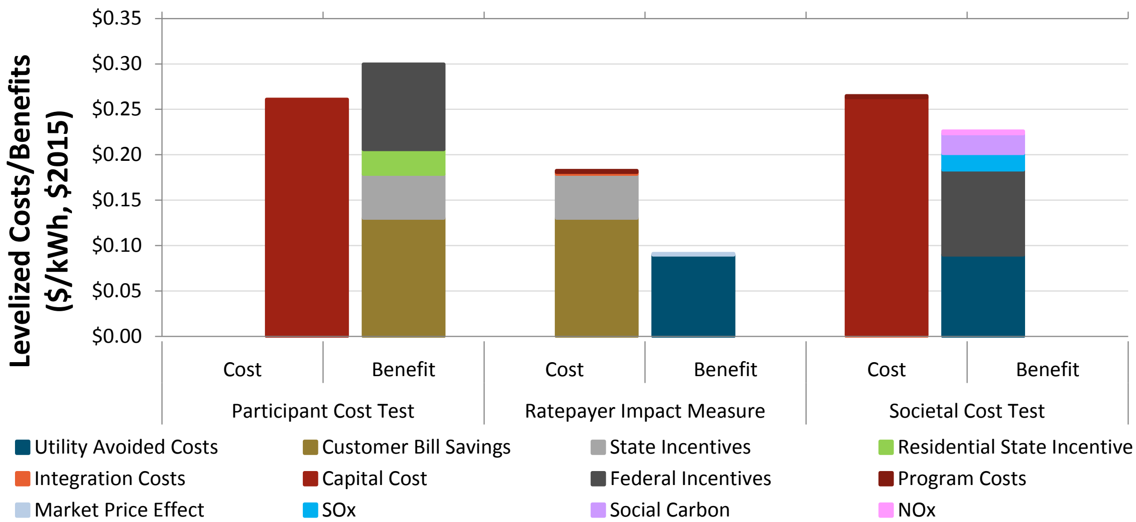


Figure 62: Levelized Costs and Benefits, RG&E, Non-Residential Class, Untargeted NEM Scenario, 2015 Vintage, Solar PV

	PCT	RIM	SCT
Benefit-Cost Ratio	1.01	0.75	1.07

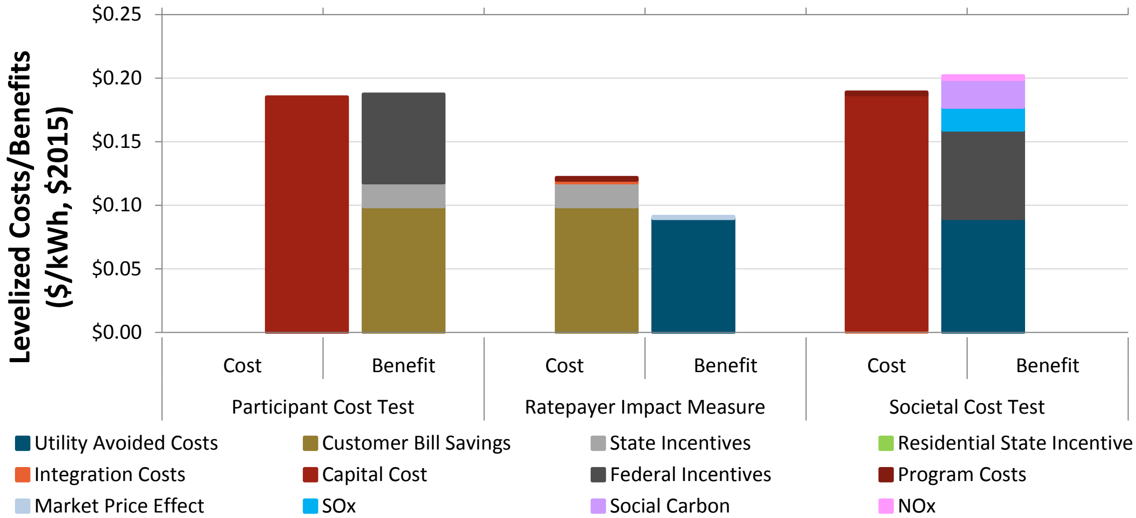


Figure 63: Levelized Costs and Benefits, PSE&G Long Island, Residential Class, Untargeted NEM Scenario, 2015 Vintage, Solar PV

	PCT	RIM	SCT
Benefit-Cost Ratio	1.26	0.52	0.90

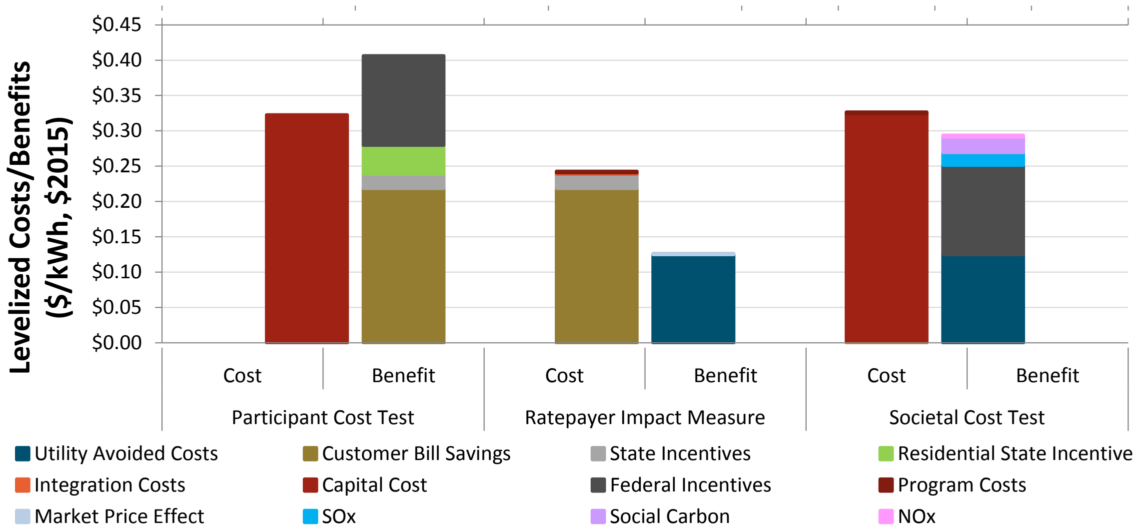


Figure 64: Levelized Costs and Benefits, PSE&G Long Island, Non-Residential Class, Untargeted NEM Scenario, 2015 Vintage, Solar PV

	PCT	RIM	SCT
Benefit-Cost Ratio	**1.29**	**0.52**	**1.00**

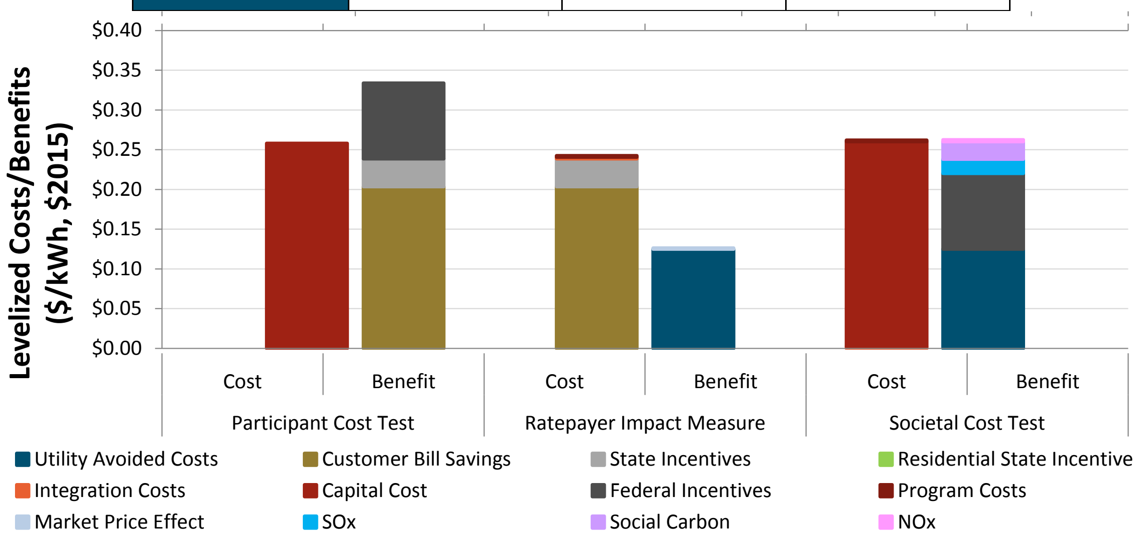


Figure 65: Levelized Costs and Benefits, Orange and Rockland, Residential Class, Untargeted NEM Scenario, 2015 Vintage, Solar PV

	PCT	RIM	SCT
Benefit-Cost Ratio	1.28	0.40	0.81

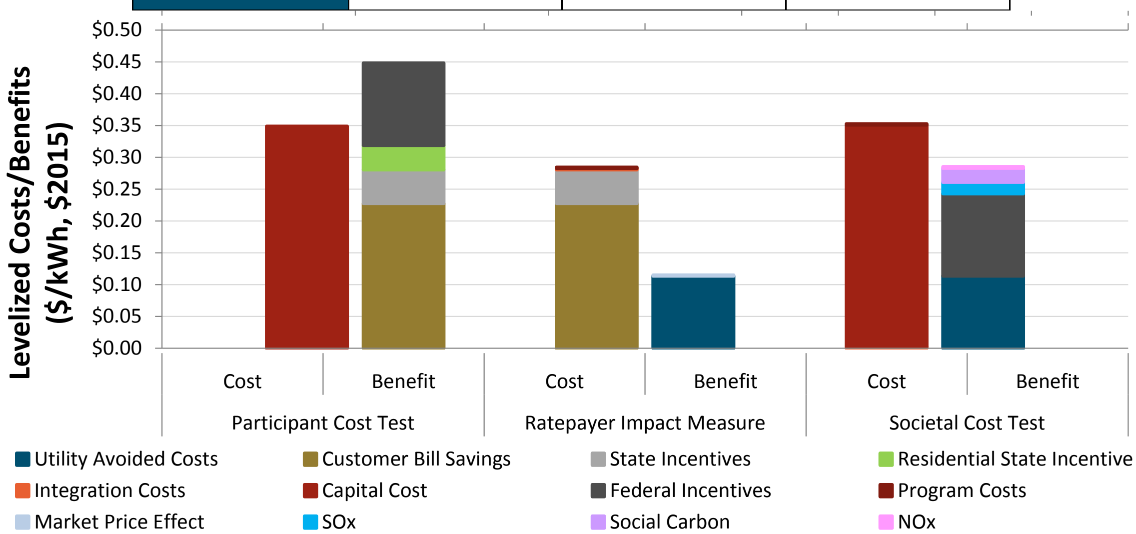
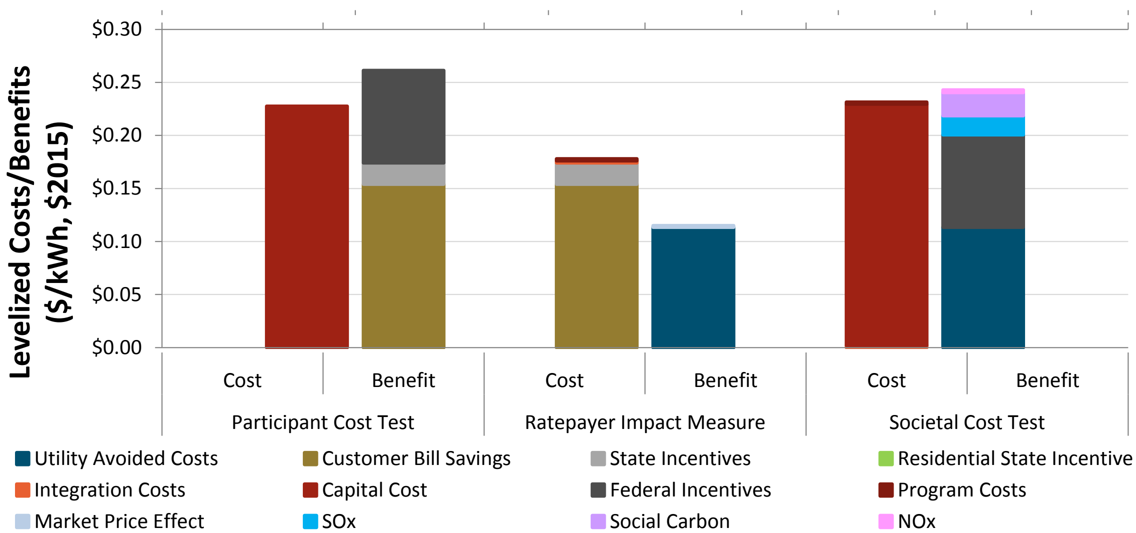


Figure 66: Levelized Costs and Benefits, Orange and Rockland, Non-Residential Class, Untargeted NEM Scenario, 2015 Vintage, Solar PV

	PCT	RIM	SCT
Benefit-Cost Ratio	1.15	0.65	1.05



1.13 Benefit-Cost Ratio Table

The following is a table of benefit-cost ratios for a number the Untargeted NEM and Targeted NEM cases for each utility for solar PV systems installed in 2015 and 2025 over the assumed 25-year life of each vintage of installation.

Figure 67: Benefit-Cost Ratios for Untargeted NEM and Targeted NEM scenarios for solar PV systems installed in 2015 and 2025.

			PCT	RIM	SCT
2015 Vintage	Untargeted NEM Scenario	Central Hudson	1.05	0.64	0.90
		Consolidated Edison	1.22	0.51	0.91
		NYSEG	1.08	0.71	1.05
		National Grid	0.99	0.71	0.97
		RG&E	1.03	0.72	1.04
		PSE&G Long Island	1.27	0.52	0.93
		Orange and Rockland	1.22	0.52	0.93
	Targeted NEM Scenario	Central Hudson	1.05	0.82	1.01
		Consolidated Edison	1.22	0.66	1.03
		NYSEG	1.08	0.87	1.15
		National Grid	0.99	0.87	1.07
		RG&E	1.03	0.87	1.14
		PSE&G Long Island	1.27	0.76	1.11

			PCT	RIM	SCT
		Orange and Rockland	1.22	0.61	1.00
2025 Vintage	Untargeted NEM Scenario	Central Hudson	1.18	0.81	1.16
		Consolidated Edison	1.43	0.63	1.16
		NYSEG	1.28	0.88	1.45
		National Grid	1.10	0.88	1.28
		RG&E	1.18	0.89	1.42
		PSE&G Long Island	1.64	0.61	1.22
		Orange and Rockland	1.49	0.63	1.21
	Targeted NEM Scenario	Central Hudson	1.18	1.01	1.35
		Consolidated Edison	1.43	0.81	1.37
		NYSEG	1.28	1.04	1.62
		National Grid	1.10	1.06	1.44
		RG&E	1.18	1.04	1.57
		PSE&G Long Island	1.64	0.84	1.53
		Orange and Rockland	1.49	0.72	1.31