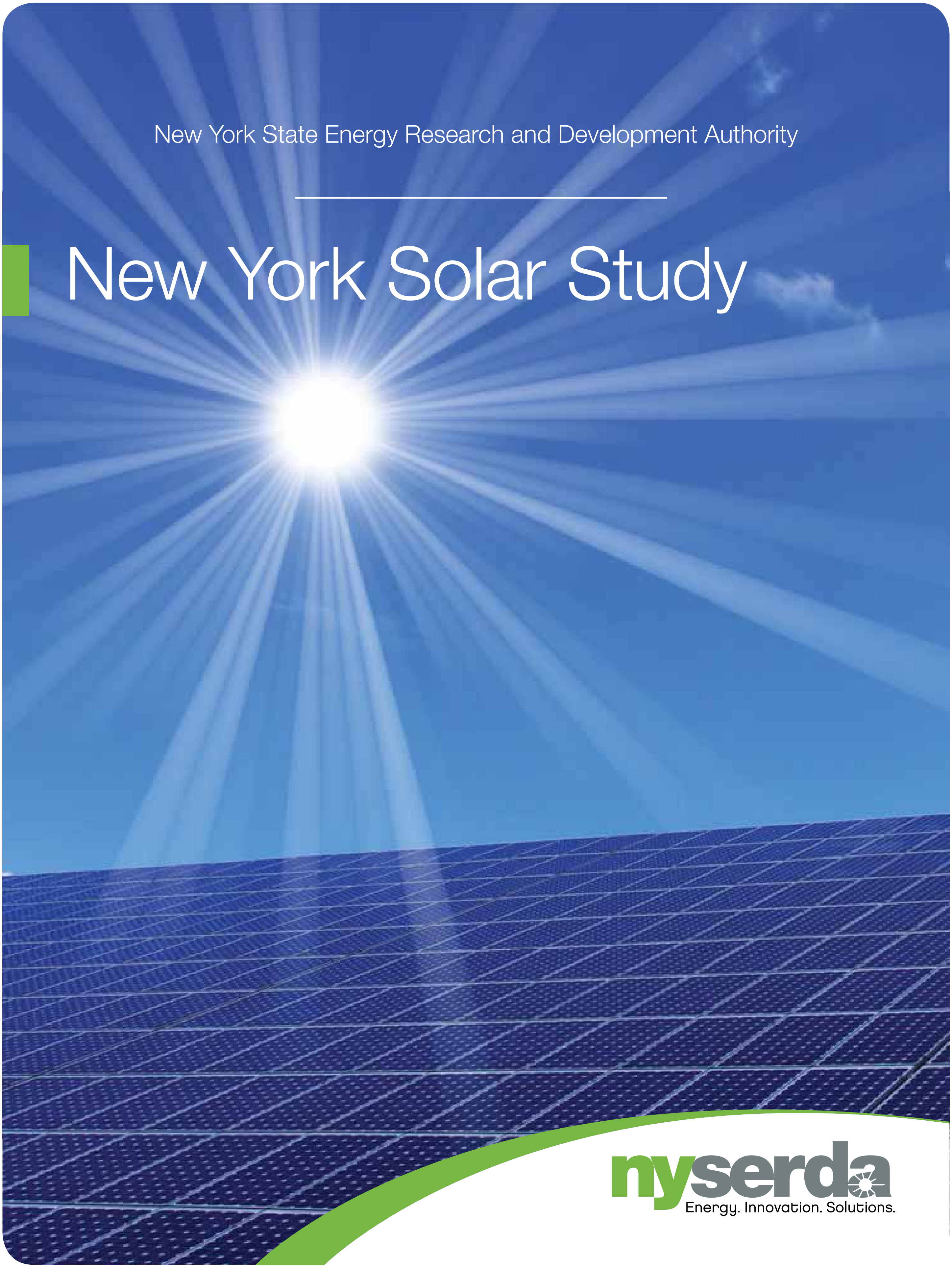
New York State Energy Research and Development Authority

New York Solar Study



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New York Solar Study:
An Analysis of the Benefits and Costs of Increasing Generation from Photovoltaic Devices in New York

Report

New York State
Energy Research and
Development Authority

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Summary of Findings and Recommendations

The Power New York Act of 2011 directed NYSERDA to conduct a study to evaluate the costs and benefits of increasing the use of solar photovoltaics (PV) in New York State to 5,000 megawatts (MW) by 2025. As requested by the Act, the following represents NYSERDA's findings and recommendations that are based on the conclusions of the technical analysis completed in the Study.

NEW YORK'S RENEWABLE ENERGY CONTEXT

New York State is a national leader in the deployment and production of renewable energy. This leadership is attributable to New York's strategic pursuit of policies designed to develop a diverse portfolio of renewable energy resources, including solar, wind, hydropower and biomass. New York's diverse portfolio approach capitalizes on the State's many renewable resources – this diversity is New York's strength. The success of this approach is reflected by the fact that New York has developed more than 1,800 MW of renewable energy, exclusive of hydropower, more than any other state in the Northeast. Including hydropower, New York's renewable energy capacity is comparable to the entire renewable energy capacity of the other eight states in the Northeast.

In a recent U.S. Department of Energy (DOE) report, New York ranked 5th in the nation for the amount of installed renewable energy capacity providing electricity to the state. New York was the only state east of the Mississippi named in the top 5, and the only Northeast state placing in the top 10.

COST OF ACHIEVING A 5,000 MW PV GOAL

There is significant uncertainty in estimating the cost of PV out to 2025. Experts project that the installed cost of PV by 2025 could range from $1.4 to $4.3 million per installed MW. This range and various assumptions about the renewal of the federal tax credit, set to expire in 2016, formed the basis of the scenarios analyzed in the Solar Study.

The Low Cost scenario is based on the DOE SunShot goal for PV cost reduction and assumed extension of the federal tax credit through 2025. The High Cost scenario is based on long-term historical trends and assumed the federal tax credit would revert to a pre-federal stimulus level following expiration of the current credit in 2016. The most likely scenario, referred to as the Base Case, is based on a survey of experts by the DOE and assumed a moderate reduction of the federal tax credit beyond 2016. The Base Case estimates $2.5 million per installed MW for large-scale systems and $3.1 million per installed MW for small-scale systems.

- The cost of achieving a 5,000 MW goal exceeds the benefits using the Base Case scenario.

- The cost of PV and the availability of federal tax credits through 2025 are the driving factors of cost in a 5,000 MW goal.

- The Low Cost scenario had a net benefit while the High Cost scenario had a net cost four times as high as the Base Case.

- In the Base Case, achieving a 5,000 MW goal would have a ratepayer impact of $3 billion over the study period (2013 – 2049), which would equal on average a 1% impact on ratepayer electric bills. In any given year, this rate impact could be as much as 3%.

  Note: The study period goes beyond 2025 because PV installations in 2025 have a 25-year life-span, and ratepayers are assumed to pay for the power generated by these installations throughout the life of the systems.

- The ratepayer impact under the Low Cost scenario would be approximately $300 million, whereas the impact under the High Cost scenario would be $9 billion.

JOB IMPACT

Modeling of the Base Case scenario found that while direct PV jobs would be created, the impact on New York's economy as a whole would be a net negative primarily due to the ratepayer impact.

- Approximately 2,300 jobs associated directly with PV installation would be created for the installation period through 2025.

- Economy-wide jobs would be reduced by 750 through 2049 because of a loss of discretionary income that would have supported employment in other sectors in the economy.

- The Gross State Product (GSP) would be reduced by $3 billion through 2049, representing an annual decrease in GSP of less than 0.1%.

- The Low Cost scenario would lead to a creation of 700 jobs economy-wide through 2049, while the High Cost scenario would lead to a loss of 2,500 jobs.

ENVIRONMENTAL IMPACT

A 5,000 MW goal would yield the following environmental benefits through 2049:

- A 4% reduction in fossil fuel consumption equal to 1,100 trillion Btus.

- A 3% reduction in carbon dioxide (CO_2) emissions equal to 47 million tons.

- A reduction of nitrogen oxides (NO_x), which produces smog and acid rain, by 33,000 tons (4%); sulfur dioxide (SO_2), which also produces smog and acid rain, by 67,000 tons (10%); and mercury by 120 pounds (3%).

POLICY OPTIONS

The study reviewed numerous government policies and best practices used around the world to stimulate demand for PV systems. Four specific policy options were analyzed to determine their relative rate impact to New York.

- Solar Quantity Obligation Using Tradable Solar Renewable Energy Credits (SRECS) with a Price Floor Mechanism, similar to approaches adopted in neighboring states. Under this policy option, utilities (or other entities) are responsible for buying SRECS (tradable certificates that represent the production of one MWh of electricity generation from a PV system) from the spot market, but prices are supported by a long-term minimum price that provides a greater degree of revenue certainty to developers and investors.

- Auction for Long-Term Contracts by Electric Distribution Companies, similar to an approach adopted by California. Under this policy option, utilities manage a competitive procurement under which they award long-term contracts to purchase renewable energy.

- Hybrid Upfront Incentives for Residential and Small Commercial & Industrial (C&I) with a Central Procurement Approach to Large C&I and MW-Scale Installations, similar to New York's current Renewable Portfolio Standard (RPS) approach. Under this policy option, rebates are provided for small PV systems and incentives for larger PV systems are provided by a central procurement entity through some type of competitive bidding.

- Hybrid Standard Offer Performance-Based Incentives for Residential and Small C&I and Auctions for Long-Term Contracts for Large C&I and MW-Scale Installations, similar to proposals under consideration in the State Legislature. Under this policy option, utilities are responsible for providing incentives to larger projects through a competitive procurement and long-term contracts. Smaller projects receive performance-based incentives, typically a standard offer (in cents per kWh produced).

The results of the four specific policy options analyzed included:

- A quantity obligation with price floor is the most expensive policy option and is projected to cost 50% more than the least-cost policy option.

- The other three policy options have comparable costs, with hybrid upfront incentives for smaller customers and central procurement for larger customers being the least expensive policy option.

RECOMMENDATIONS

Given the major uncertainties in PV technology cost reductions and the continued availability of federal tax credits over this time period, there is a significant range in the potential cost estimates to ratepayers of meeting a 5,000 MW goal by 2025.

The magnitude and range of this cost uncertainty ($300 million – $9 billion) is substantial, and strongly suggests the need for a policy response and investment strategy that is both flexible and responsive.

Nevertheless, even with this range of cost uncertainty, given the many potential benefits that PV has to offer and the long-term potential for lower-cost PV technology, New York State should support continued investment in the steady and measured growth and deployment of PV as part of a sound and balanced renewable energy policy.

New York should strengthen such investment through continued development of policies such as net metering, sales tax exemptions and interconnection standards that could further reduce the cost of PV installation and remove barriers to reaching the targets.

This strategy should also be complemented by additional efforts to reduce the balance of system costs for PV, including more streamlined permitting processes, and continued financial support for targeted research and development, workforce training and business development.

Continued federal incentives will play a critical role in the magnitude and predictability of future PV prices. In addition, the SunShot goal articulated by the DOE is an aggressive and meritorious goal that, if achieved, would substantially reduce PV cost and change the benefit-cost equation. New York State should strongly support continued federal incentives and aggressive federal research efforts to reduce the cost of PV to consumers.

Abstract and Keywords

Signed into law on August 4, 2011, the *Power New York Act of 2011* required the New York State Energy Research and Development Authority, in consultation with the Department of Public Service, to develop a study regarding policy options that could be used to achieve goals of 2,500 MW solar photovoltaic (PV) installations operating by 2020 and 5,000 MW operating by 2025 in New York. The Act acknowledges that costs are declining and noted the potential for PV energy generation to contribute to economic development and job creation in the State.

This study estimates the benefits and costs associated with the deployment of 5,000 MW by 2025 using scenario analyses. Specifically, the study conducts analysis that takes into account a range of economic factors including the future price of installed PV to estimate costs and the potential ratepayer impact. This study also analyzes the net macroeconomic and job creation impacts of deploying 5,000 MW by 2025. The environmental benefits are also analyzed focusing on reductions in air pollution and land use impacts.

The study conducts a qualitative and quantitative comparison of potential administrative and policy mechanisms that could be used to achieve the deployment goals, and reviews policy structures, best practices, cost control mechanisms, and lessons learned from case studies.

Keywords:

Photovoltaic

Solar energy

Job creation

Environmental impact

Ratepayer impact

Policy

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EXECUTIVE SUMMARY

1. INTRODUCTION

Signed into law on August 4, 2011, the *Power New York Act of 2011* (the "Act") required the New York State Energy Research and Development Authority (NYSERDA), in consultation with the Department of Public Service (DPS), to develop a Study to Increase Generation from Photovoltaic Devices in New York (the "Solar Study"). While the current contribution of photovoltaic (PV) energy generation is small and the cost of the technology is at a premium compared with current electricity prices, the Act sought analysis of the benefits and costs of PV, acknowledging that costs are declining and noting the potential for PV energy generation to contribute to economic development and job creation in the State.

Specifically, the Act directed that the Solar Study should:

- Identify administrative and policy options that could be used to achieve goals of 2,500 Megawatts (MW) of PV installations operating by 2020 and 5,000 MW operating by 2025 (the "Goals");
- Estimate the per MW cost of achieving increased generation from PV devices and the costs of achieving the Goals using the options identified in the analysis;
- Analyze the net economic and job creation benefits of achieving the Goals using each of the options identified in the analysis; and
- Conduct an analysis of the environmental benefits of achieving the Goals using the options identified in the analysis.

1.1. PV Deployment Scenario and Study Approach

Key Finding:

- The pace of annual PV capacity additions drives the timing and magnitude of annual rate impacts, employment impacts, costs, and benefits. As such, the pace of PV development is a central component of any PV policy design. Policymakers should therefore consider the actual cost of annual development in establishing policy targets, so as to craft a flexible and responsive policy.

The Solar Study used a comprehensive suite of analytical tools and techniques to model the impacts of achieving the Goals. Case studies and secondary sources were also used to develop policy options, as well as to characterize the global and New York PV markets. A PV deployment scenario was developed that projected annual PV capacity additions needed in order to meet the 2,500 MW by 2020 and 5,000 MW by 2025 Goals, as shown in Figure ES-1. The pace of annual PV capacity additions drives the timing and magnitude of annual rate impact, employment impacts, costs, and benefits. As such, the pace of PV development is a central component of any PV policy design. Policymakers should therefore consider the actual cost of annual development in establishing policy targets, so as to craft a flexible and responsive policy. This would more likely create a predictable investment environment while not burdening ratepayers with the impacts of extreme price volatility.

The PV deployment scenario assumed that the New York market would grow annually in response to state and federal incentives, the cost of PV technologies would decline, and the required installation labor per PV system would be reduced. This annual deployment path is shown in Figure ES-1 below. The PV deployment scenario also laid out specific geographic and PV system size distributions for PV capacity additions for the New York City, Upstate, Capital, Long Island and Hudson Valley regions.[1] A second deployment scenario, which projected the State's PV installations under existing program and polices, was also developed as a Reference Case to isolate the impacts of the Goals of the Act.

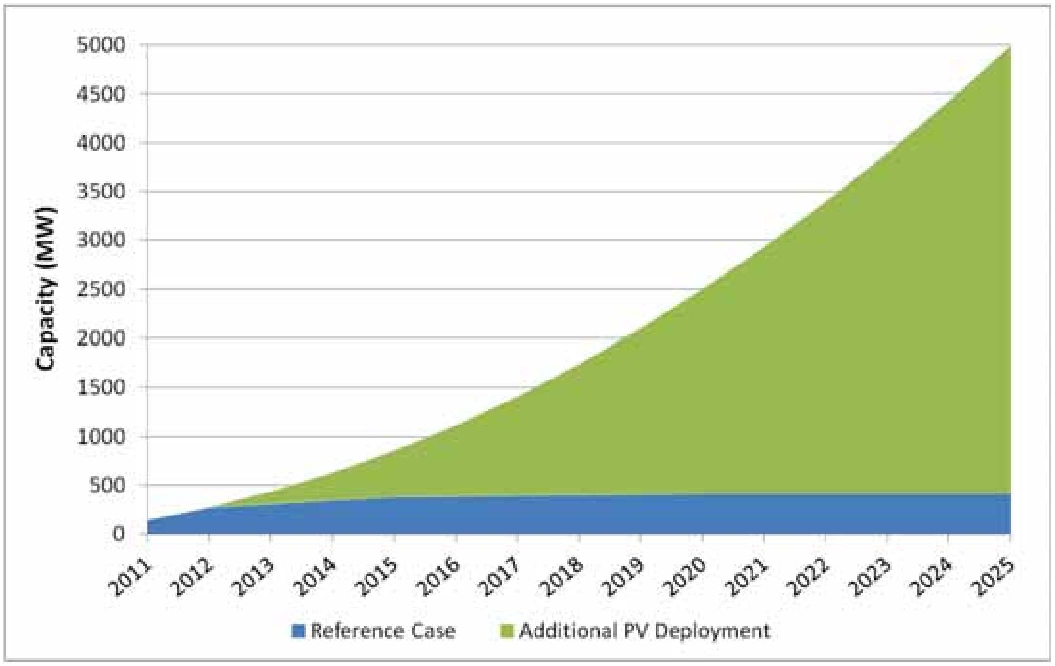


Figure ES-1. PV Capacity Target and Path

The total costs of meeting the Goals were developed using a cost-of-energy analysis, which examined a range of future costs and potential regional installation scenarios. To accurately estimate possible PV cost trajectories, the scenarios varied the future cost of PV equipment, level of federal incentives, location of installations, and system sizes. The energy cost analysis used the National Renewable Energy Laboratory's Cost of Renewable Energy Spreadsheet Tool (CREST) to estimate lifetime average energy costs for each of the modeled scenarios. A comparative cost analysis of non-PV renewable energy technologies was also completed, using the CREST model.

1 The base PV deployment scenario geographic distribution was based on historical load distribution for New York and the projections of system size distributions were based on historical trends and data from other states that have seen large-scale PV deployment.

The benefits associated with meeting the Goals include: avoided electricity production costs, reduced air pollution, reduced use of fossil fuels, lowered wholesale electricity prices for all consumers (called price suppression), avoided distribution system upgrades, and avoided line losses. These benefits were estimated using the Integrated Planning Model (IPM), which determined how the electricity system would be impacted by achievement of the Goals. Benefits were calculated to 2049, the final year when PV systems installed under the program were assumed to be operating. To accurately estimate the range of possible benefits, different assumptions for the price of natural gas and the economic value of emissions were explored.

These costs and benefits were analyzed to assess the net impact on all New Yorkers, including analysis of ratepayer impacts.

The impacts of meeting the Goals on New York's economy (measured by changes in employment and gross state product) were developed using a Regional Economic Models Inc. Policy Insight (REMI PI+) model. The REMI PI+ model is an advanced macroeconomic model that combines an input-output model with a dynamic ability to forecast shifts in prices and competitiveness factors over time to determine impact to the whole economy. The economic impacts were analyzed for a range of future PV costs and natural gas prices.

The Solar Study also identifies a series of policy mechanisms that were incorporated into the modeling scenarios. These were identified through research of best practices of national and international PV incentive programs. This work included the development of comprehensive case studies of some of the largest global PV markets. Diverse incentive mechanisms are currently being implemented worldwide to drive PV demand, and many of these could be used to meet the Goals analyzed in this Solar Study. Each of the policy mechanisms identified as part of the Solar Study would be adequate, if properly implemented, to meet a 5,000 MW target. The Solar Study does not recommend a single policy or specify policy implementation details, rather it describes the strengths and limitations associated with the different policy mechanisms and recommends additional considerations should any mechanism be pursued.

To isolate the impact of a single policy, the Solar Study analyzes only the impact of achieving a 5,000 MW goal by 2025. This was necessary in order to isolate the impact of this policy for analysis purposes. The Solar Study does not measure the effects of transformation in the marketplace or demand for PV products outside the scope of a 5,000 MW target; thus, no PV systems were modeled as installed after 2025, no PV systems were modeled as being replaced at the end of their assumed economic life, and no PV systems were assumed to continue producing electricity (albeit at a reduced level) after the end of their economic life. Incorporating these issues would present a number of analytical challenges. There is considerable uncertainty in predicting market dynamics more than 15 years into the future. In addition, further study is necessary to determine the degree to which new PV installations beyond 2025 should be attributed to the policies being studied. Among other challenges would be the development of additional novel reference cases correlating to different costs and federal incentives in the future.

The Solar Study did not directly address the potential physical value of certain applications of PV on the New York power grid, including localized reliability impacts (such as supporting existing network conditions and/or affecting future grid planning and operating resources) and how such applications may be enabled by targeted PV deployments.

1.2. New York in the Global PV Market

Key Findings:

- The global PV market has recently seen dramatic declines in PV panel prices.
- These declines have benefited New York, with installed costs dropping significantly in the past three years.
- The existing global supply chain could adequately meet the needs of New York's market as it grows toward the 5,000 MW target.

The global PV market has grown substantially over the last decade, led by several European Union (EU) countries with well-funded PV incentive programs and aggressive PV targets. As the global PV market supply chain has expanded and PV technology has improved, the costs of PV has decreased significantly over the past few decades. Figure ES-2 shows the growth of the global PV market as well as the market prices for PV panels from 2000 to 2010. As the figure shows, within this general decrease, PV prices rose from 2004 to 2006. This was largely the result of a global shortage of polysilicon, one of the key raw materials in the silicon PV supply chain.

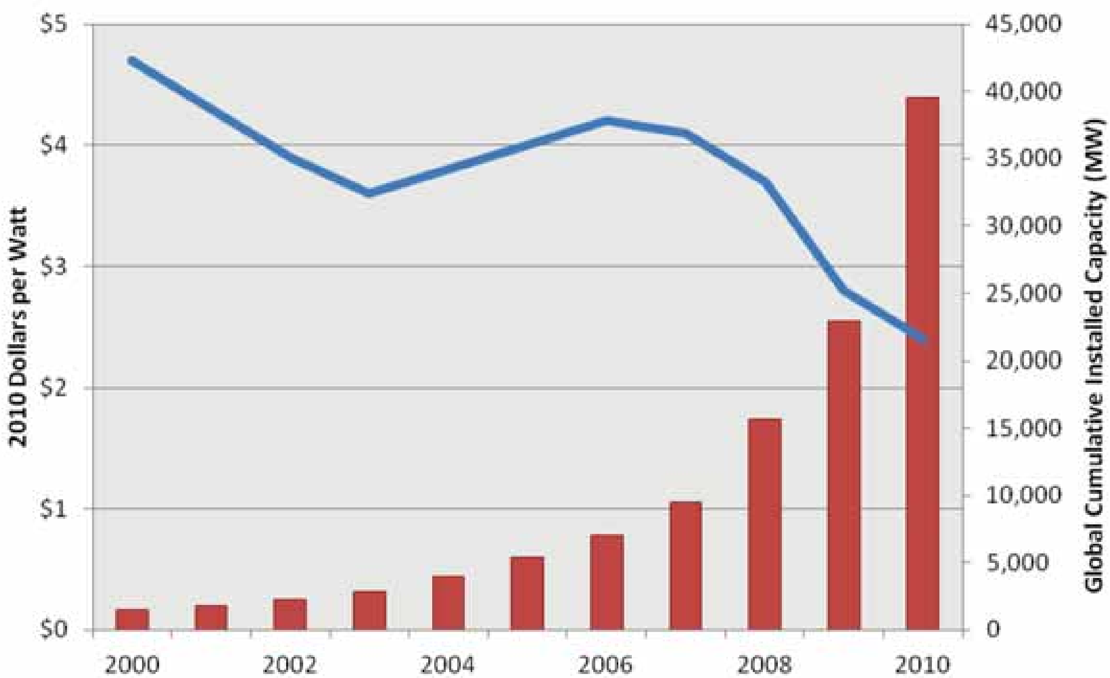
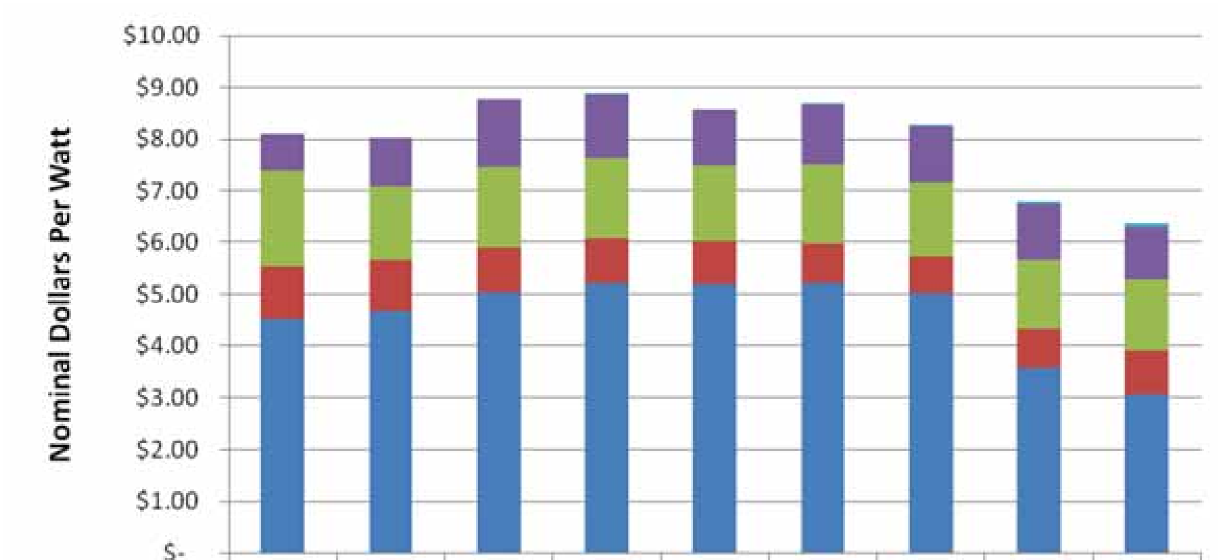


Figure ES-2. Global PV Module Price Index and Cumulative Installed Capacity

New York has benefited from this long-term global downward price trend. Supported by stable state-level incentives and comprehensive ancillary policies,[2] installed costs for PV systems in the NYSERDA incentive program have declined more than 20% since 2003. As seen in Figure ES-3, this decrease has been led by substantial decreases in PV module costs in the past two years. Balance of System (BOS) includes all of the PV hardware components other than the module and inverter.



	2003	2004	2005	2006	2007	2008	2009	2010	2011
Other $/W	$-	$-	$-	$0.01	$-	$0.00	$0.01	$0.05	$0.08
BOS $/W	$0.72	$0.93	$1.30	$1.22	$1.07	$1.15	$1.11	$1.07	$1.02
Labor $/W	$1.87	$1.44	$1.56	$1.58	$1.47	$1.53	$1.41	$1.34	$1.38
Inverter $/W	$1.01	$0.98	$0.89	$0.85	$0.83	$0.76	$0.73	$0.75	$0.84
Module $/W	$4.51	$4.67	$5.02	$5.22	$5.19	$5.22	$5.01	$3.57	$3.06

Figure ES-3. NYSERDA Database of Installed Cost 2003-2011

The recent increase in demand from countries in the EU has led to a rapid expansion of the global PV supply chain. Global market demand was estimated to be 16.6 GW in 2010 and industry analysts estimate that there is currently significant manufacturing overcapacity in several key value chain components. Existing global manufacturing capacity would be sufficient to meet the needs of the New York market if it met a 5,000 MW by 2025 Goal. Under the modeling assumptions used for this study, PV panel demand for 2025 in New York would represent little more than 2.5% of current global PV panel capacity.

2 New York has a wide range of policies and programs that support the growing PV market. These include net-metering regulations, workforce development and technology and business development initiatives, outreach programs, and residential tax credits, as well as well-funded direct incentives.

1.3. Policy Objectives

A comprehensive list of policy objectives was not defined in the Act; however, identification of these objectives was necessary to evaluate and compare the scenarios and sensitivities studied. A broad set of potential objectives was identified based on an examination of current New York renewable energy policies and other industry experience with solar policies,[3] in order to shape the selection of policy options evaluated.

The policy objectives identified were organized into general categories, as shown in Table ES-1 below. Using the policy objectives, corresponding quantitative and qualitative metrics were developed to measure progress toward meeting the objectives in the various cases studied herein. An important observation is that some policy objectives conflict — maximizing one may take away from maximizing another. As such, different policy approaches may yield different tradeoffs among these objectives. For example, reducing installation costs will also reduce the number of jobs needed to install the systems.

[3] The proposed policy objectives was based on a literature survey of potential policy objectives and constraints from a range of sources, including (i) the Act; (ii) previously introduced New York solar legislation, such as the NY Renewable Energy Sources Act, A00187A (2009); NY Solar Industry Development and Jobs Act, A11004 (2010); and NY Solar Jobs Act, A05713 (2011); (iii) existing NY renewable energy programs, particularly the RPS; (iv) solar policy goals from other states as summarized in *When Renewable Energy Policy Objectives Conflict: A Guide for Policy-Makers* (Grace, Donovan, & Melnick, 2011); (v) published studies by the National Renewable Energy Laboratory (NREL, 2011a), Deutsche Bank (DB Climate Change Advisors, 2009) and the California Energy Commission (KEMA, 2010).

Table ES-1. Policy Objectives

Category	Policy Objectives
Environmental	• Minimize greenhouse gas emissions • Minimize criteria pollutant, mercury and other air pollution emissions • Reduce impacts related to water use in thermal electric generation (thermal, quality, quantity) • Preserve land from fuel cycle impacts (mining, drilling, etc.) • Minimize use of land with higher value alternative uses • Reduce reliance on finite fossil fuels
Energy Security and Independence	• Increase fuel diversity • Increase energy security and supply reliability • Increase domestic energy production
Reliability	• Reduce electric delivery disruption risk • Minimize negative grid planning and operating reserve impacts • Minimize distribution system negative reliability impacts (avoiding degradation of system loss of load probability)
Economic Development	• Maximize net in-state job creation • Maximize gross state product (GSP) growth • Support existing clean technology industries • Minimize out-of-state capital flows • Create stable business planning environment (for supply chain investment)
Energy Cost	• Reduce distribution system upgrades and minimize additional upgrades caused by PV • Reduce wholesale prices (energy and capacity impacts) • Minimize direct cost of policy to ratepayers • Minimize total cost of policy (exclusive of monetizing environmental, public health or other impacts) • Integrate well with competitive retail market structure in NY • Integrate well with competitive wholesale market structure in NY
Technology Policy	• Create a self-sustaining solar market • Assist emerging technologies in becoming commercial technologies • Foster technology innovation and development
Societal	• Ensure geographic distributional equity/ effectiveness at aligning benefits with those who bear the costs • Maximize benefits to environmental justice communities

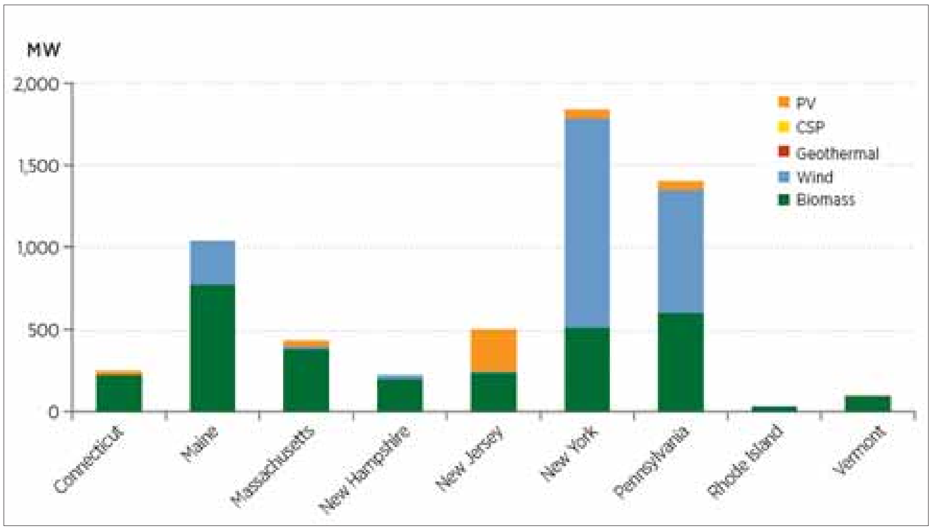
2. NYS RENEWABLE ENERGY POLICY CONTEXT

Key Findings:

- New York has aggressive renewable energy goals and robust policies that support those goals.
- Current New York policies support a range of renewable technologies including several high-cost early-stage generation sources, like PV, that have the potential to reach significant market penetration as costs decline.
- New York has taken a holistic approach to development of a robust renewable energy market, including PV, through workforce development, as well as technology and business development initiatives.

- Existing PV programs in New York have stimulated a stable and growing market, but this market is small in relation to other East Coast markets.

New York has approached renewable energy through the development of a diverse portfolio of resources. While two-thirds of New York's installed renewable capacity is from hydropower, it also has significant capacity from wind, biomass, and PV. A U.S. Department of Energy publication reports that as of 2010, New York has developed more than 1,800 MW of renewable energy, excluding hydropower — more than any other state in the Northeast, as shown in Figure ES-4. Additionally, when hydropower capacity is included, New York's renewable energy capacity is comparable to the entire renewable capacity of the other eight states in the Northeast.[4]



Sources: EIA, LBNL, GEA, SEIA/GTM, Larry Sherwood/IREC, U.S. Census[5]

Figure ES-4. Renewables 2010 Installed Capacity (Excluding Hydropower) in the Northeast

Much of the non-hydropower renewable energy development in New York State is a result of its renewable energy target – one of the most aggressive in the nation. First adopted in 2004, current New York policies require that 30% of the state's electricity come from renewable sources by 2015. New York meets its renewable energy targets through several programs, including a unique Renewable Portfolio Standard (RPS) mechanism that, unlike other states, includes a centralized procurement of renewable energy attributes, with the programs being administered by NYSERDA.

New York's RPS program is designed to support a diverse portfolio of energy generation technologies, from wind and PV, to biomass and hydropower. In order to ensure a diversity of energy sources, the New York RPS has both a

4 Overall, New York is ranked 5th in the nation for electric renewable energy installed capacity. New York was the only state east of the Mississippi named in the Top 5, and the only Northeast state placing in the Top 10.

5 The figure was obtained from NREL's 2010 Renewable Energy Data Book. The report was produced by Rachel Gelman, edited by Scott Gossett, and designed by Stacy Buchanan of the National Renewable Energy Laboratory (NREL). The document can be found at www.nrel.gov/analysis/pdfs/51680.pdf.

Main Tier, which has supported large-scale generation projects, and a Customer-Sited Tier (CST), which is designed to support smaller, emerging energy generation technologies for use on customer sites. Figure ES-5 shows a breakdown of currently operating energy generation resources developed through the RPS program over the life of the initiative ("other" resources include anaerobic digester gas-to-electricity, small wind and fuel cells). Figure ES-5 does not include PV projects that have been awarded but not yet installed.

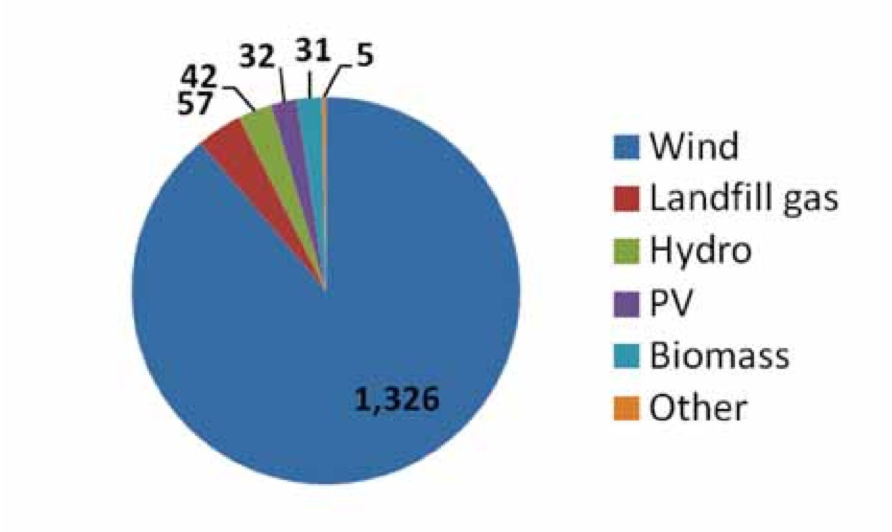


Figure ES-5. Cumulative Generation Project Types Supported Through the New York RPS in MW (2011)

The RPS CST has been the major driver of the New York PV market outside of Long Island over the course of the past decade, wherein NYSERDA has provided over $100 million in incentives for PV projects. These incentives have been provided in the form of upfront payments to project owners to help buy-down the cost of installing PV. Incentives have been designed to promote growth in both the residential and small commercial PV market.

More recently, the CST has also supported PV installations as part of an ongoing regional program. Funding totaling $30 million was released in the first two rounds of competitive bidding for the CST regional program (also known as the "geographic balance" program) in 2011, which resulted in awards to develop 26.6 MW of PV in the lower Hudson Valley and New York City regions. A total of $150 million is devoted to this program through 2015.[6] Through the CST, including the regional program, NYSERDA expects to develop more than 170 MW of PV capacity by 2015.

On Long Island, the Long Island Power Authority (LIPA) has been operating PV incentive programs since 2000. Historically, these programs have been well-funded and have led to the development of a robust PV market on Long Island. LIPA's current programs include an upfront incentive program for homeowners and small businesses, as well as a power purchase initiative that is developing several utility-scale PV systems for wholesale power generation.

6 The CST regional program supports both PV and biogas facilities; however it is anticipated that the majority of the funding from this initiative will support PV installations.

This initiative includes the development of the largest PV facility on the East Coast, a 32 MW system at Brookhaven National Laboratory, which was commissioned in November of 2011. To date, LIPA's initiatives have supported more than 70 MW of PV. It is expected that under current programs, more than 140 MW of PV will be developed on Long Island by 2020. Additionally, the New York Power Authority (NYPA) has developed nearly 2 MW of PV projects on public properties over the last 15 years.

While these incentive programs have been a key component driving the New York PV market, PV systems have also benefited from a number of other state and federal incentives. These include both a federal Investment Tax Credit (ITC) and a 5-year Modified Accelerated Cost Recovery System (MACRS) depreciation for commercial systems.[7] Residential PV systems also benefit from a 30% federal tax credit as well as a 25% state tax credit. A suite of other ancillary policies including net metering and local property tax exemptions are also available in New York and are critical to driving the New York market.

Figure ES-6 below shows the development of the New York PV market between 2002 and 2011 by funding source.

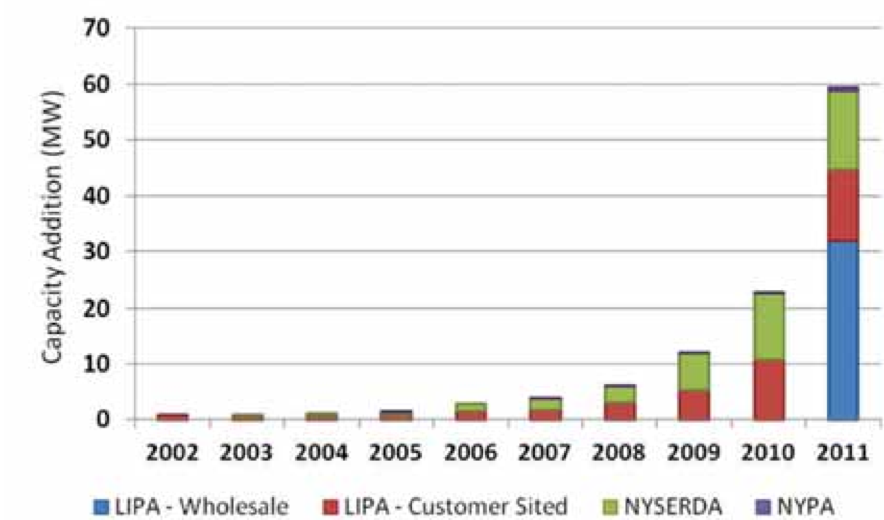


Figure ES-6. Annual PV Capacity Additions in New York (2002-2011)[8]

This diverse suite of PV incentive policies has created a stable and growing PV market in New York and has supported a growing PV installer base, with over 370 individuals eligible to serve as primary installers on NYSERDA-supported PV projects. By developing a comprehensive and steady PV incentive funding strategy, New York has avoided the boom and bust market cycles that have created uncertainty in a number of East Coast markets in recent years. These funding programs have also led a number of national PV development firms to enter the New York market. Additionally, New York has a history of using complementary policies and programs to support the industry, including those in the areas of workforce development and technology and business development.

7 The 5-year MACRS expired on January 1, 2012.

8 The LIPA – Wholesale Scale bar consists of a single 32 MW installation at Brookhaven National Labs. The LIPA PV wholesale PV power purchase program is expected to install 17MW in 2012.

Compared with PV programs in other East Coast states, however, the New York PV market has been limited in size. In 2011, New Jersey installed 240 MW while Pennsylvania installed 91 MW. This compares to New York's 59 MW installed state-wide in 2011. Until recently, caps on the existing incentive programs in New York limited the development of large commercial and MW-scale PV systems, which is a substantial portion of the PV market in other East Coast states. Nevertheless, the recent implementation of the NYSERDA regional program, as well as LIPA's development of utility-scale PV projects, have led to greater diversity in the state's PV generation fleet.

3. PV COST PROJECTIONS

Key Findings:

- By 2025, the cost of PV is expected to significantly decline, where the Base Case installed cost will range from $2.50 per W for MW-scale systems to $3.10 per W for the residential-scale system, in nominal dollars. For the Low Cost Case, the range is $1.40 per W to $2.00 per W and for the High Cost Case the range is $2.90 per W to $4.30 per W.
- PV is not expected to achieve wholesale parity during the analysis period (2013 thru 2049) in any cost future.
- Retail parity may be achieved, and will occur sooner in New York City than in other regions of the state. This suggests a greater leverage of state PV incentive dollars in New York City. In a low-cost future there is parity in New York City by 2017.
- PV cost of energy is expected to be more expensive than large-scale onshore wind energy and will most likely be more expensive than offshore wind in 2025.
- PV cost of energy may be competitive with small-scale wind energy and greenfield biomass technologies by 2025.
- Due to the differences between what is measured by cost of electricity and by the value of the energy produced, it is recommended that a full study of the costs and benefits of other renewable energy technologies be conducted to better inform renewable energy policy development.
- Continued federal incentives will play a critical role in the magnitude and predictability of future PV prices. In addition, the SunShot goal articulated by the U.S. DOE is an aggressive and meritorious goal that, if achieved, would substantially reduce PV cost and change the benefit-cost equation. It is recommended that New York should strongly support continued federal incentives and aggressive federal research efforts to reduce the cost of PV to consumers.

As technologies have advanced and the size of the global market has grown, PV prices have declined significantly in the past decade. Supported by stable incentive programs and favorable ancillary policies, costs in New York have followed this trend with average prices in 2003 at $8.11 per W while systems installed in 2011 averaged $6.38 per

W. While the general price trend has been downward, market prices for system components have been volatile over the past several years, with a shortage of silicon driving up prices for PV panels between 2004 and 2006. Similarly, a global silicon and panel supply glut is currently affecting the market, with panel prices declining between 20 and 30% over the past 12 months.

As a result of this recent short-term volatility of the PV market, price forecasts for the Solar Study were developed based on long-term market trends and publicly-available price forecasts. Three PV cost cases were developed, representing potential High, Low and Base Case installed costs. The High Cost Case was derived based on the national average annual PV system price decline over the past decade. The Base Case was developed on the results of a 2009 U.S. Department of Energy PV expert survey, while the Low Cost Case was an adaptation of the U.S. Department of Energy's SunShot initiative. Figure ES-7 shows the cost trajectories for these and other PV price scenarios evaluated for the Solar Study.

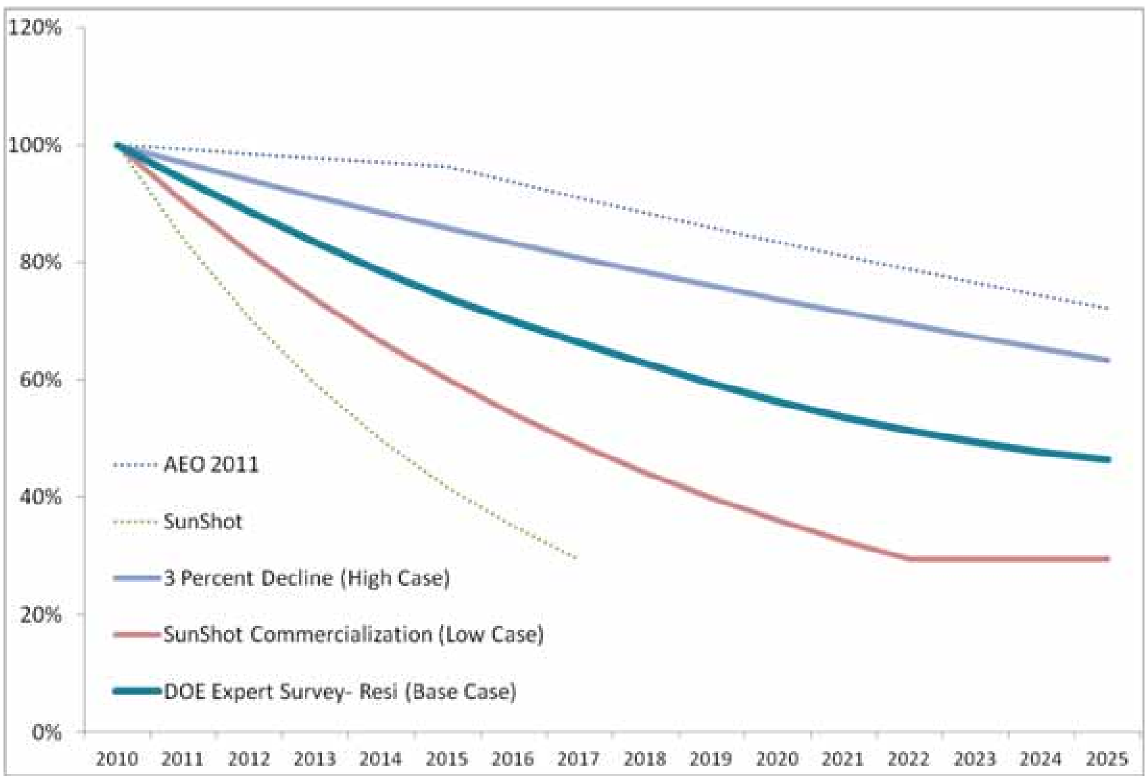


Figure ES-7. Forecast PV Installed Cost Trajectories (2010-2025)

Capital cost trajectories from the three selected cases were applied to New York PV market prices using 2010 as the starting point. The analysis estimated PV system installed costs for residential, small commercial, large commercial and MW-scale PV systems in the Upstate, New York City and LIPA-load zones. Projections were developed through the final 2025 installation year. Under the Base Case trajectory, residential systems for non-New York City sites declined from $6.70 per W to $3.10 per W in 2025, while costs for these systems under the Low Cost Case declined to $2.00 per W in 2025. Similarly, small commercial systems in Upstate New York declined from $6.30

per W in the 2010 analysis year to $3.00 per W in 2025. Under the Low Cost Case, installed costs for these systems declined to $2.00 per W in 2025. In comparison, MW-scale systems in the upstate region declined from $4.40 per W to $2.50 and $1.40 per W in the Base and Low Cost Cases respectively.

3.1. PV Cost of Energy Compared to Retail and Wholesale Electricity Prices

An often-stated PV strategy is to support the above-market technology until the cost of PV achieves "grid parity." A PV installation is said to reach "grid parity" when lifetime average energy costs equal the retail cost of power purchased from the grid. Although grid parity is frequently assumed to be the point when PV will be widely adopted, some policy intervention will likely still be necessary to increase market demand. This conclusion is supported by experiences from energy efficiency programs, where incentives are frequently necessary to drive demand for technologies that have average costs that are below retail electricity rates. In particular, the upfront cost of PV installations will likely continue to be a barrier to widespread adoption, even if average generation costs reach grid parity. Innovative ownership structures, such as third party leasing or power purchase agreements (PPAs) are increasingly used in the New York market to address this first-cost issue.

The Solar Study examined energy costs for a range of system types and installation load zones, considering installed cost trajectories, financing assumptions, and federal policy scenarios, throughout the 2011 to 2025 analysis period. Base Case modeling assumptions included:

- **Federal Incentives:** Federal ITC continues at 30% through 12/31/2016 and then phases down to 15% over a 5-year period, remaining at this reduced level indefinitely.[9]
- **Financing Structure:** 50/50 debt-to-equity ratio with 15-year debt at 6% and 12% cost of equity.

Energy production for each of the four installation types (residential, small commercial, large commercial and MW-scale) were developed using PVWatts, a PV production estimator developed by the National Renewable Energy Laboratory. The cost, financing and production assumptions were input into the CREST model to develop projected energy costs for each system type in each load zone for each cost and financing scenario.

The energy cost modeling was highly sensitive to federal incentives and PV cost assumptions. Modeling showed that retail grid parity will be reached in different regions of New York in different years, with areas of the state that have better PV resources and higher electricity prices reaching grid parity before areas with relatively poor PV resources and lower energy prices. Small commercial systems in New York City would reach retail grid parity in 2017 in the Low Cost Case with Upstate installations approaching retail grid parity by 2025. One potential policy focus to explore could target resources to areas of the state that are likely to reach grid parity sooner. This could

9 For the Low-Cost scenario, the federal tax credit was assumed to extend through 2025 at its current level. For the High-Cost scenario, the federal tax credit was assumed to revert to a pre-federal stimulus level following expiration of the current credit in 2016.

lower the costs of reaching the 5,000 MW Goal. None of the scenarios in this analysis showed PV cost competitive with wholesale electricity generation during the study period.

3.2. PV Cost of Energy vs. Other Renewable Technologies

The analysis compared expected PV energy costs with energy costs for other renewable energy technologies including biomass, onshore and offshore wind, hydropower and landfill gas. Figure ES-8 compares energy costs for large-scale systems, by technology, in 2025. As with the grid-parity analysis, PV costs were highly dependent on installed cost assumptions. Under the Base Case, MW-scale systems in the Capital Region are forecast to have a higher cost of energy than all other modeled resources, with the exception of small new hydroelectric resources. In the Low Cost Case, the PV costs are forecast to also have a lower cost than high-cost offshore wind, small onshore wind, and greenfield biomass. All other resources, including large onshore wind and the offshore wind low cost case, are forecast to have lower costs than the PV Low Cost Case.

The comparison of PV to wind energy may be more instructive than the comparison to other technologies, as wind is presently the only other technology with both a high installation growth rate and substantial additional resource potential. Wind energy is the resource that is likely to set the price for compliance with policies that require the development of new, large-scale renewable energy facilities. Other resources may represent lower cost supply in limited quantities. This quantity-oriented view is an important consideration in the policy-making process and is not adequately represented by looking at a comparison of energy costs alone.

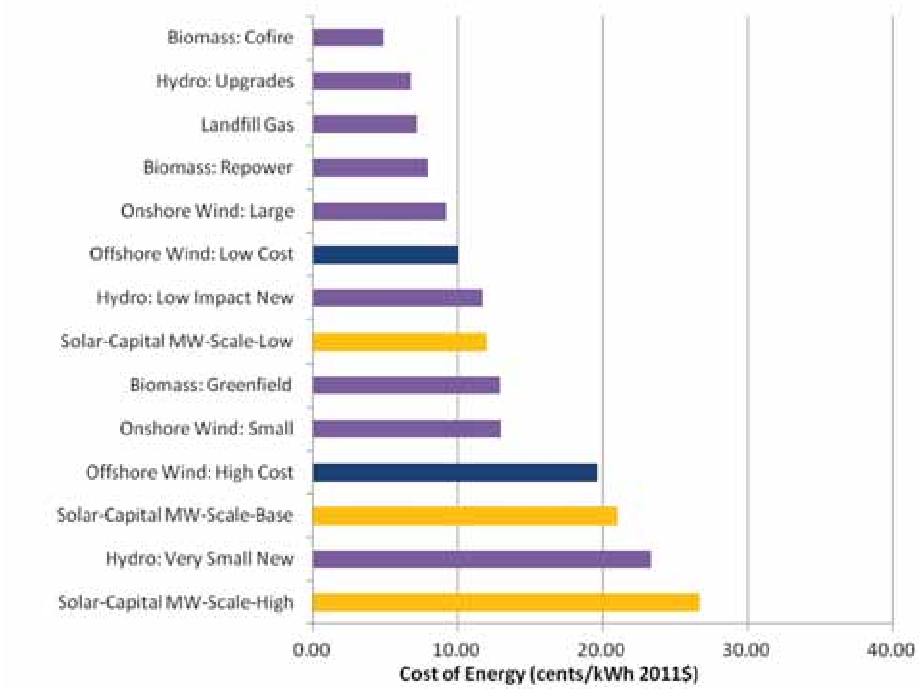


Figure ES-8. Renewable Energy Cost Comparisons in 2025

It should be noted that distributed technologies such as PV have value that is not fully accounted for in this analysis. Examples of other potential, but uncertain benefits that have been studied elsewhere, including PV's potential to mitigate or hedge ratepayer exposure to fuel cost variability and PV's ability to enhance grid security.

4. BENEFIT-COST ANALYSIS

Key Findings:

- Future cost of PV and the federal incentive level were the primary drivers of total cost of reaching the Goal, while the location of installations and system sizes were secondary cost drivers.
- Price suppression and avoided electricity production costs were the greatest drivers of benefits, while other factors, including reduction in air pollution, reduction in the use of fossil fuels, avoided distribution system upgrades, and avoided line losses showed smaller benefits.
- Under the Base Case scenario, reaching the 5,000 MW Goal had a net cost for New York of $2 billion.
- Under the Low Cost Case scenario, reaching the 5,000 MW Goal had a net benefit for New York of $2 billion.
- Under the High Cost Case scenario, reaching the 5,000 MW Goal had a net cost for New York of $8 billion.
- Increased deployment of PV downstate had a higher benefit-cost ratio, lowering the overall costs of meeting the Goal by nearly $1 billion, as electricity costs are higher in the New York City region.

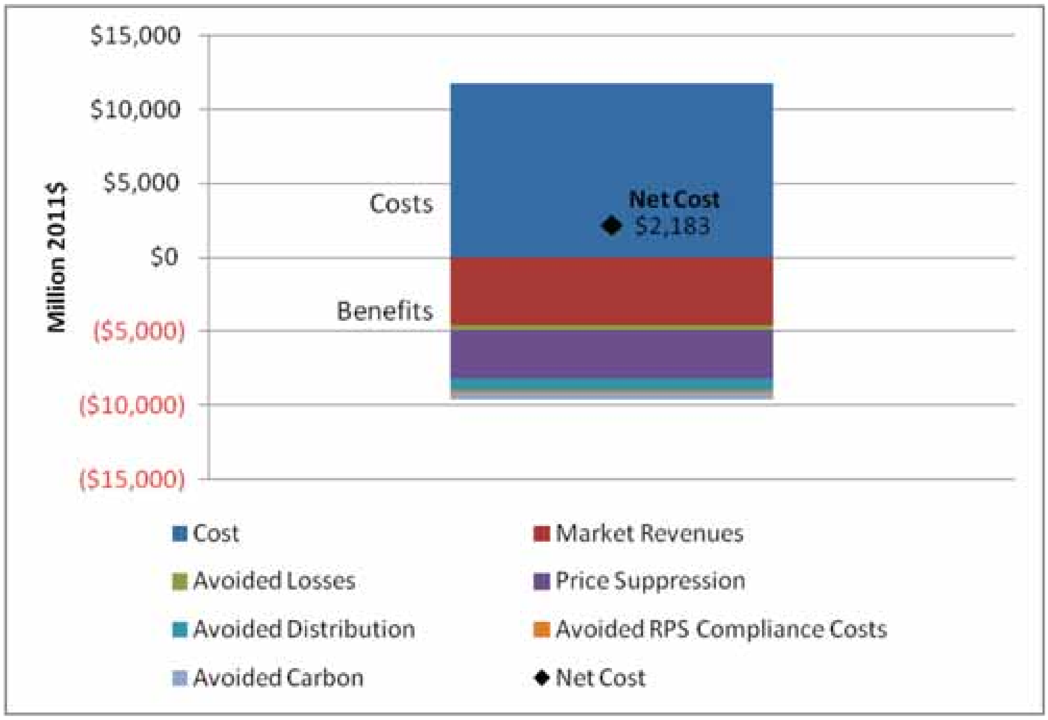
The benefits and costs of the implementation of the 5,000 MW by 2025 Goal were studied. A range of benefits were quantified for the Base Case deployment scenario from 2013 through 2049 — the final year when PV systems installed during the policy implementation period were expected to still be generating. These benefits included:

- **Wholesale Energy Market Value:** the estimated dollar value of the electricity exported to the grid
- **Wholesale Capacity Market Value:** the value of a PV system to the grid's generation capacity market
- **Avoided Losses:** this value reflects the benefits of generating power closer to its point of consumption, reflected as a reduction in energy lost to transmission and distribution inefficiencies
- **Price Suppression:** this is the value to electricity consumers of reducing electricity demand in the wholesale market, lowering electricity prices for all customers
- **Avoided Distribution Costs:** installation of distributed generation such as PV can reduce or defer the need to upgrade the utility distribution system
- **Avoided RPS Compliance Costs:** this is the benefit of displacing the purchase of renewable energy credits from other sources with PV to meet the requirements of the state's renewable portfolio standard
- **Monetized Carbon Values:** this is the monetized value of avoiding future carbon emissions (a carbon value of $15 per ton was used to develop the carbon benefit price)

Modeling showed that price suppression and avoided electricity production costs were the greatest drivers of benefits, while other factors, including reduction in air pollution, reduction in the use of fossil fuels, avoided distribution system upgrades, and avoided line losses showed smaller benefits.

The costs of the Base Case scenario were also quantified. These costs included the cost of installing PV generation assets and the administrative costs associated with developing and operating a PV incentive program. Modeling showed that future cost of PV and the federal incentive level were the primary drivers of total cost of reaching the Goal, while the location of installations and system sizes were secondary cost drivers.

The benefit cost analysis found that, for the Base Case implementation, the costs outweighed the benefits by $2.2 billion. Figure ES-9 shows the total lifetime benefits and costs of the PV deployment.



Note: Positive equates to costs while negative equates to savings

Figure ES-9. Lifetime Cost and Benefit of Base Case Scenario

A series of sensitivity analyses were performed to better understand the impacts of other deployment scenarios on the cost of reaching the PV deployment targets. This analysis found that a geographic PV deployment scenario that favored more downstate installations lowered the overall costs of meeting the targets by nearly $1 billion. This was because power generated in downstate regions had higher wholesale value and improved price suppression effects.

A second sensitivity analysis was completed to understand the potential effects of higher future natural gas costs on the overall cost of achieving the Goal. Under this scenario, the benefits of PV increased by more than $1 billion for a net policy cost of $1.1 billion. These benefits included increased wholesale value for PV generation as well as increased wholesale price suppression effects.

5. JOBS AND MACROECONOMIC IMPACT

Key Findings:

- Analysis conducted looked at the overall impacts to the New York job market, taking into consideration the jobs gained in the solar industry and elsewhere, as well as the potential job loss due to the costs imposed on the economy by the Goal.
- In terms of the total impact of the Base Case PV deployment on the economy, there will be no economy-wide net job gain; in fact, modeling showed an economy-wide net loss of 750 jobs because of the impact of increased electricity rates needed to pay for the PV program. Gross State Product (GSP) would be reduced by $3 billion between 2013 and 2049, representing a small annual decrease in GSP of less than 0.1%.
- Deployment to a level of 5,000 MW will create approximately 2,300 direct PV jobs associated with PV installation for the installation period (2013–2025) and an average of approximately 240 direct jobs associated with Operations and Maintenance (O&M) from 2025–2049.
- There will also be 600 jobs lost for the study period primarily as a result of the reduced need to expand and upgrade the distribution grid, a reduced need for conventional power plants, and reductions in in-state biomass fuel production.
- The sensitivity analysis demonstrates that a Low Cost Case future would lead to economic growth, including the creation of 700 economy-wide net jobs and an additional $3 billion in GSP, while a High Cost Case future would lead to a reduction in GSP of $9 billion and on the order of 2,500 economy-wide net job losses.
- Subsidies at the scale required to achieve 5000 MW by 2025 would most likely have a small net-negative impact on the economy; however, continued support for PV is warranted given the promise of a low-cost PV future.

Although it is clear that the installation of 5,000 MW will create new PV industry jobs in New York, the broader implications for the New York economy are more complex and require more in-depth modeling to determine how the positive impacts of PV development balance against the negative impacts of the electricity rate increases needed to pay for the PV program. Furthermore, the creation of a 5,000 MW PV goal cannot be assumed to change the PV supply chain in New York State.

Three key jobs and economic indicators that were calculated for this Study include: direct PV jobs, economy-wide net jobs, and changes to GSP.

5.1. Direct PV Jobs

Direct PV jobs include jobs that are associated with PV system installation, operations, and maintenance. In New York, these jobs would be concentrated in the fields of construction, engineering, legal and financial services, and wholesale trade. Figure ES-10 below shows direct job creation for the Base Case, as well as for High Cost and Low

Cost Cases. The jobs for all three scenarios can be categorized according to whether they result from the initial PV investment or from O&M activities. As can be seen in Figure ES-10 below, PV installation activity creates jobs until 2025, after which point jobs are created only by O&M activity. The Base Case results in an average of 2,300 direct jobs during the installation phase from 2013 to 2025. The Low Cost Case results in 1,800 direct jobs, and the High Cost Case results in 2,800 direct jobs. The number of O&M jobs created during the O&M phase (2026 to 2049) for all three scenarios is approximately 240.

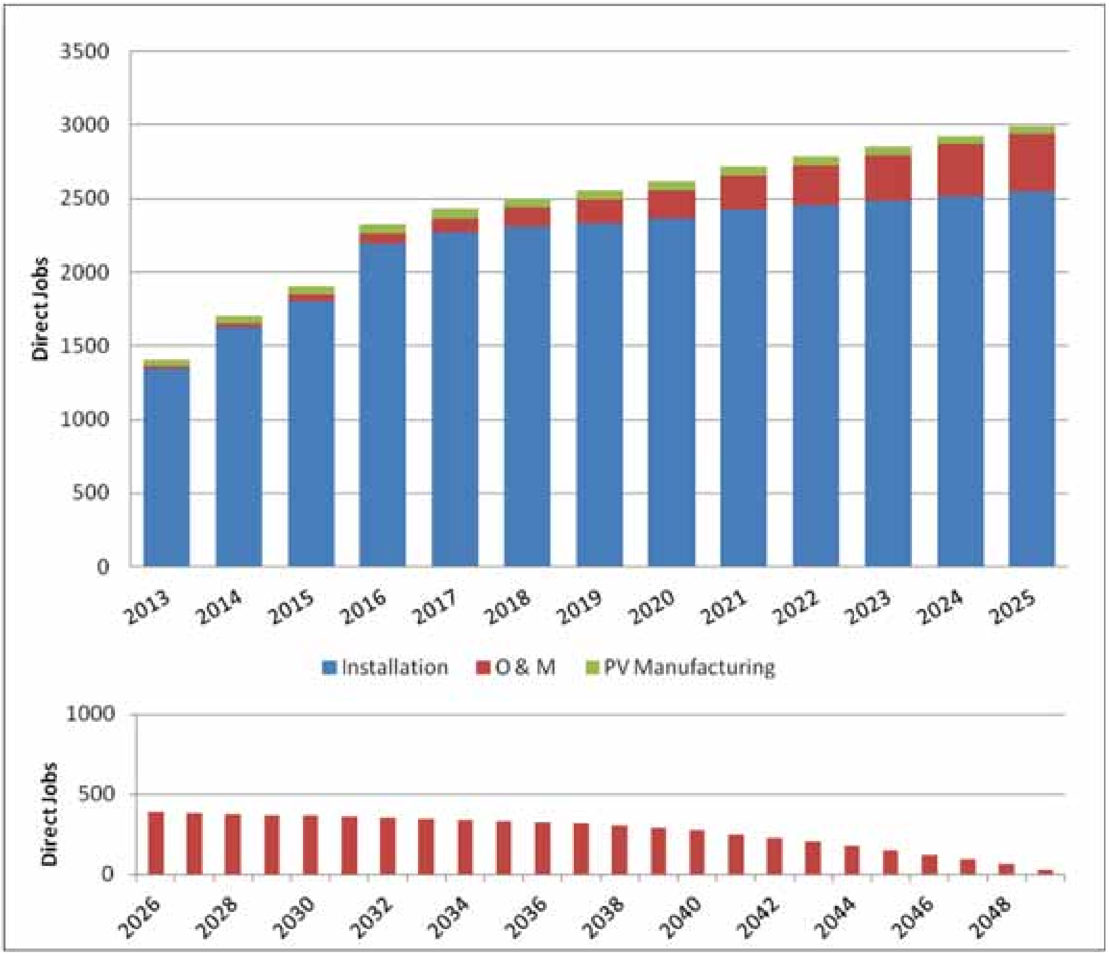


Figure ES-10. Source of Annual Direct PV-related Job Changes - Base Case

In addition to the direct PV jobs created, the installation of PV will also create direct job losses in some sectors as PV electricity reduces demand for electricity from other sources. Since PV is sited close to the loads it serves, there will be less need for expanding and upgrading the electric distribution system. As a result, labor and manufacturing jobs related to the distribution grid will decrease in the future. PV will also decrease demand for other types of fuel and power plants. Jobs will be lost from a diminished need for the construction of power plants that would otherwise be built. Although most fuels come from out of state, some biomass production occurs in New York and some jobs in biomass fuel will also be lost as PV increases. In total, an annual average of 400 direct job losses will occur over the course of the study period.

5.2. Economy-Wide Net Jobs

Economy-wide net job calculations take the effect of PV investment on the entire New York State economy into account. This includes positive impacts such as the creation of new PV jobs and the savings to ratepayers when electricity prices are suppressed by PV output. Economy-wide net jobs also take into account job losses attributable to negative impacts on the economy, such as the cancellation of new power plants that are made unnecessary by the added PV capacity and the additional costs of PV incentives, which reduce the amount of capital consumers have to spend in the economy. Economy-wide net jobs are calculated using the REMI PI+ model, an advanced economic model that reflects New York's industry mix and considers the salient interconnections between multiple industries across the entire state. Economy-wide net jobs are calculated for the Base Case, Low Cost Case, and High Cost Case. As shown in Figure ES-11 below, the number of economy-wide net jobs created is highly sensitive to the cost of PV. The best outcome is delivered by the Low Cost Case, under which 700 economy-wide net jobs will be created.[10] The Base Case results in a loss of 750 economy-wide net jobs, whereas the High Cost Case results in a loss of 2,500 economy-wide net jobs. Economy-wide net jobs are created in each of the first 13 years of the program, stimulating the economy; but net jobs are lost in the last 23 years of the study period. It is important to note that this analysis assumes that the manufacturing sector in New York continues to supply 5% of components and that the remainder of PV system components is imported from out-of-state.

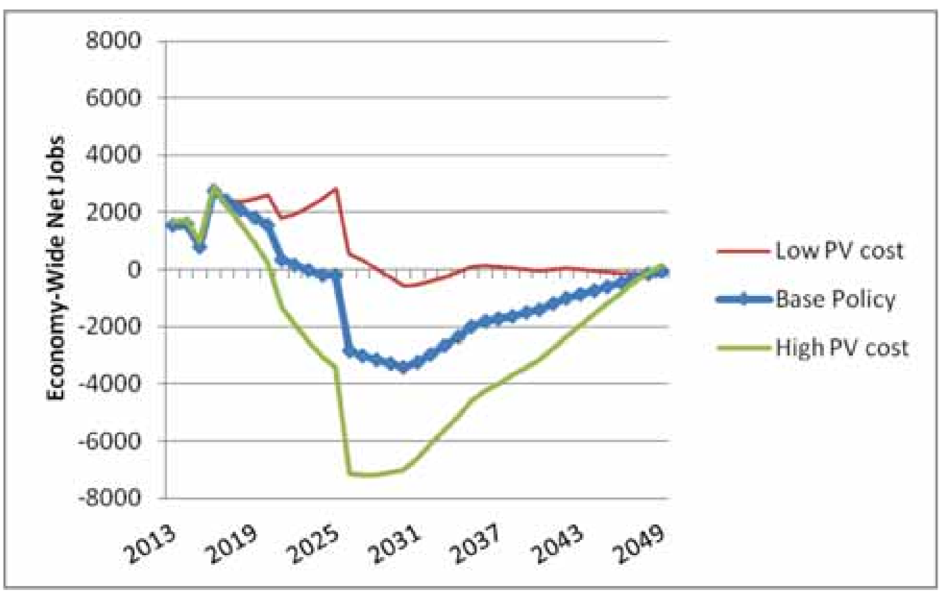


Figure ES-11. Economy-Wide Net Job Impacts across PV Cost Cases

10 The job results represent a simple total of the annual job values over the 37-year span of the study. Other ways of totaling jobs across years could be used that give greater weight to near-term numbers than to out-year numbers.

The overall result of negative economy-wide net jobs is primarily because of the high relative cost of PV compared to other forms of traditional or renewable generation. This cost necessitates rate increases, which, in turn, create job losses that offset the direct jobs created in the New York PV industry. This result should not necessarily be assumed to apply generally to renewable energy policies. Other forms of renewable generation, especially those whose costs are substantially lower than PV's costs, can be expected to produce better macroeconomic results since they will not necessitate electric rate increases of the same magnitude as PV.

5.3. Gross State Product (GSP)

Gross State Product (GSP) represents the total amount of worker income and corporate profit that is generated across the New York economy as a result of the 5,000 MW PV program. GSP is calculated using the REMI PI+ model for the Base Case, as well as for Low Cost and High Cost Cases. As shown in Figure ES-12 below, the pattern of the impact for GSP is similar to that of economy-wide net jobs. Only the Low Cost Case results in a net gain to the State economy, at $2.7 billion in net present value (NPV). The Base Case results in a loss of $2.9 billion, whereas the High Cost Case represents a loss of GSP totaling $10 billion.

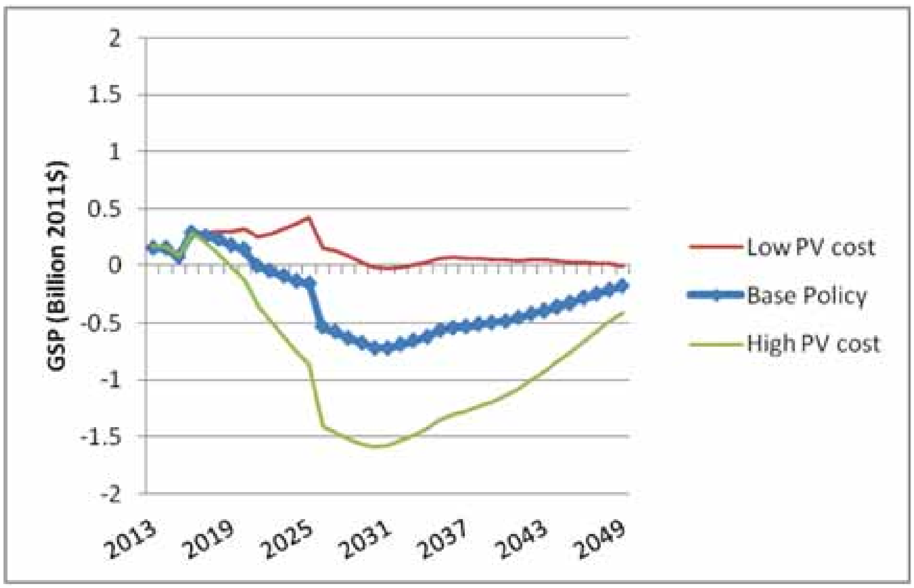


Figure ES-12. Total GSP Impacts across PV Cost Cases (Billion 2011$)

6. RETAIL RATE IMPACTS

Key Findings:

- The net impact of the PV deployment on electricity bills takes into account the above-market costs of PV, the costs of net metering, and the savings generated by the suppression of wholesale electricity prices.

- The net impact of these factors on retail electricity rates is $3 billion over the study period, or approximately 1% of total electricity bills. In any given year, this rate impact could be as much as 3% of total electricity bills.
- Analyses of Low Cost and High Cost scenarios were also conducted. The impact of the Low Cost scenario is approximately $300 million in additional ratepayer impacts or 0.1% of total bills (annually a maximum of 1%), whereas the impact under the High Cost scenario would be $9 billion or 2.4% of total bills (annually a maximum of 5%).
- An analysis was also conducted to determine the effect of higher natural gas prices on PV impacts. Higher natural gas prices would reduce the above-market cost of PV and lower the retail rate impact to 0.6% of total electricity bills (annually a maximum of 2%) instead of 1%.
- Since retail rates are higher in Southeast New York, PV is closest to grid parity downstate. Concentrating smaller-scale PV installations downstate would result in lower overall retail rate impacts.

It is assumed that any incentive costs needed for deploying 5,000 MW of PV would be recovered from New York State ratepayers through their electricity bills. As the total amount of PV installed increases, so, too, will the total impact on electricity rates.

The installation of 5,000 MW of PV will ultimately have an impact on the electricity bills that New Yorkers pay. These impacts include both the additional costs of PV incentives and savings from the wholesale electricity market price reductions that PV installations can achieve. The Study takes both costs and savings into account and calculates the net retail impact of PV incentives borne by ratepayers over time. The factors that are taken into account in this calculation include:

- **The direct rate impact of the above-market cost of PV.** The above-market cost of PV at the retail level is the difference between the cost of electricity generated from PV systems and the price at which customers purchase electricity from the grid. This calculation is done for each year of the study period. The above-market costs of PV decrease over time as the price of electricity from the grid rises, as the cost of PV systems declines, and as the more expensive PV systems that are assumed to be installed early in the study period are assumed to be retired later on.
- **The net metering impact.** Many PV generators will consume PV electricity on their own property and will get credit at the retail electricity rate for both the PV electricity that they consume and that they export to the grid under the state net metering law. The ability to net meter is a benefit to PV system owners. Still, net metering also represents a cost to the ratepayers who do not participate in the net metering program. The price of electricity from the grid reflects the cost to produce the electricity and the cost of building and maintaining the grid itself. Customers who use their PV electricity onsite avoid paying a portion of the transmission and distribution rates. These costs must then be recovered from other ratepayers via increases in retail rates. In calculating the impact of PV deployment on ratepayers, this “cross-subsidy” was taken into account.

- **The price suppression effect.** As more PV is installed on the grid, it increases the supply of electricity and reduces the wholesale market price for electricity from the grid. This price suppression impact lowers electricity prices for all customers and partially offsets the additional costs of PV incentives and net metering. The price suppression effect, however, is temporary and small compared to the additional cost impacts.

Figure ES-13 shows the net rate impact of the projected PV installations over the study period. The period of rate reduction in the early years of the study period reflects the electricity price suppression impact. Electricity price suppression also has the effect of delaying the maximum ratepayer impact from the initial deployment until several years after total installations peak in 2025. The total net present value of the impact under Base Case assumptions is $3.3 billion, or approximately 0.9% of total electricity bills over the study period. Retail rate impact is also highly sensitive to PV cost. Under the sensitivity analyses, the result of the Low Cost Case is $340 million in additional ratepayer impacts (0.1% of total bills), whereas it is $8.6 billion under the High Cost Case (2.4% of total bills).

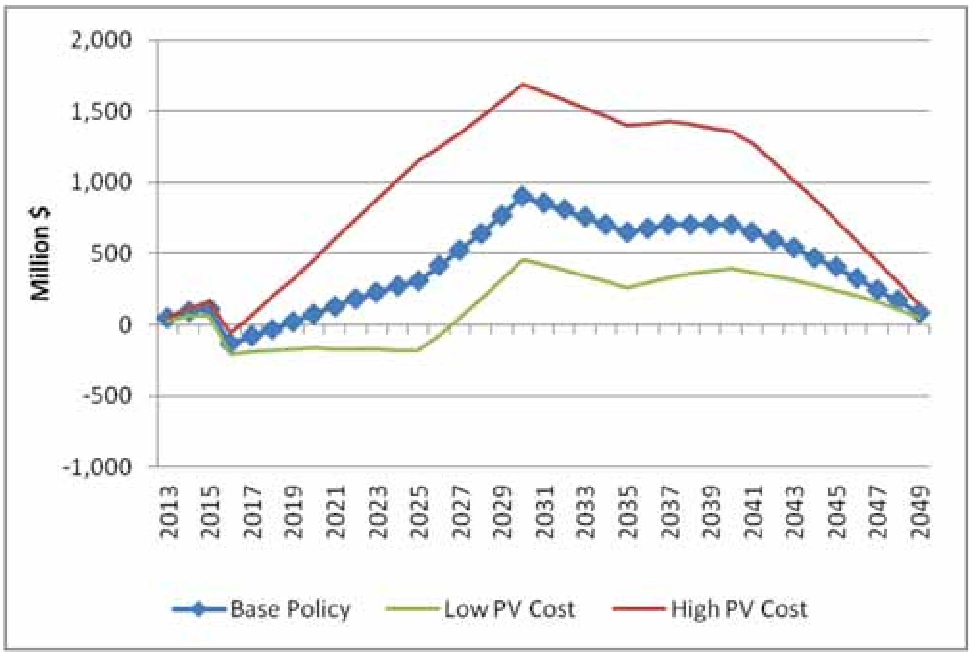


Figure ES-13. Annual Net Rate Impact, Base, Low and High PV Cost, 2013-2049 (nominal$)

Several additional analyses were performed in order to calculate the impact of different scenarios, including the impact of natural gas prices and the impact of concentrating PV in different regions of New York State. Specifically, the effect of higher natural gas prices on the rate impact was analyzed, as were the impacts of installing a greater amount of PV in downstate areas and the impacts of installing a greater amount PV in upstate New York. As can be seen in Table ES-2 below, higher natural gas prices would decrease the impact of PV on retail rates. Likewise, the concentration of a greater amount of PV downstate would decrease the total impact on retail rates, whereas a greater concentration upstate would increase the total impact on retail rates. This is because retail rates are higher in downstate areas and so the above-market costs are lower, whereas the opposite is true of upstate areas. Put another way, PV electricity prices are currently closer to parity with the price of electricity from the grid downstate than they are in upstate New York. Concentrating PV downstate would minimize total electricity bill impact compared to other geographic distributions.

Table ES-2. Net Rate Impact as % of Total Bill, Base Policy and Sensitivities, NPV, 2011$

Scenario	Average (2013-2049)
Base	1%
High natural gas prices	0.6%
Greater downstate deployment (Alternative A)	0.7%
Greater upstate deployment (Alternative B)	1.4%

7. ENVIRONMENTAL IMPACTS

Key Findings:

- Over the study period (2013–2049) PV will reduce fossil fuel consumption by 1,100 trillion Btus (TBtus). This includes a 7% reduction in the use of natural gas, a 4% reduction in the use of coal, and a 40% reduction in the use of oil in the electricity sector in 2025.
- This reduction will lower carbon dioxide (CO_2) emissions by 47 million tons, equivalent to taking an average of approximately 250,000 cars off the road for each year of the study period. The CO_2 emissions reduction is valued at $450 million for the Base Case.
- A high valuation for CO_2 emission reduction values the 47 million tons at $3.2 billion and has a significant enough benefit to make the Base Case net-beneficial to New York.
- The amount of CO_2 reduction remains small compared to the total reduction that was identified for the power generation sector in the New York State Climate Action Plan Interim Report. In 2025, PV will reduce emissions by 1.7 million metric tons, or 5% of the emissions from the electric generation sector in that year.
- The reduction in fossil fuel use will lower nitrogen oxides (NO_x) by 33,000 tons, sulfur dioxide (SO_2) by 67,000 tons and mercury by 120 pounds. The net present value of this combined reduction is $130 million over the study period. This valuation is based on health benefits only, and does not attempt to monetize ecosystem benefits (such as reduction in acidification of lakes, streams and forests, and eutrophication of estuaries and coastal waters).
- In 2025, PV will reduce total NO_x emissions by 4%, total SO_2 emissions by 17%, and total mercury emissions by 6%.

- PV could also require land for site systems. It is estimated that 5,000 MW of PV would require 23,000 acres of land if the entire amount were ground-mounted. Still, there is a significant amount of roof space available, as well as areas such as brownfield sites, existing power plant sites, and parking lots where PV could be deployed without using land that could have other productive uses. In total, it is estimated that PV would require from 2,600–6,000 acres of greenfield space total, which is less than 0.02% of total state land area.

The installation of 5,000 MW of PV in New York will positively impact the environment by reducing the use of fossil fuels for electricity generation. Fossil fuels create environmental burdens at every stage of their fuel cycle, from ecosystem and human health impacts associated with the extraction process, to air and water emissions from plant operation, to disposal issues associated with toxic waste products. By reducing the need for fossil fuel power plants, PV will reduce these negative impacts. In total, 5,000 MW of PV would reduce fossil fuel consumption in power plants by 1,100 TBtus. Table ES-3 below lists the total amount of coal, natural gas, and oil that is projected to be consumed in 2025 and as well as the projected reduction in consumption resulting from PV installations.

Table ES-3. Projected Reductions in Fossil Fuel Consumption from PV Generation in 2025

Fuel type	Amount consumed in 2025 (TBtus)	Fuel displaced by PV in 2025 (TBtus)	% reduction in fuel consumption in 2025
Coal	110	8	7%
Natural gas	460	20	4%
Oil	2	0.80	38%

7.1. Air Pollutants

The electricity generation sector is a major source of emissions of several air pollutants that impact the environment and public health. These include carbon dioxide (CO_2), which contributes to global climate change, sulfur dioxide (SO_2) that contributes to acid rain and fine particle concentrations in the atmosphere (causing asthma and other health problems), nitrogen oxides (NO_x) that contributes to both of these pollution problems and to ground-level ozone (a lung irritant that also damages trees and crops), and mercury, which is a toxic substance linked to neurological and other health problems. The Solar Study focused on the value of the reduced air pollutants achieved by a reduction in fossil fuel use.

7.1.1. Carbon Dioxide

Over the course of the study period, it is projected that PV would displace a total of 47 million tons of CO_2. To put these reduction numbers in context, the net present value of these reductions would be between $450 million and $3.2 billion. The two values for CO_2 reflect the fact that there is significant uncertainty in accurately monetizing the value of a ton of CO_2. The lower value is the same assumed in the benefit-cost analyses contained in Chapter 4, and reflects the assumption that CO_2 reductions are valued at $15/ton. This is the current value used by DPS as part of electricity generation sector benefit-cost tests. The higher value uses an assumption of $107/ton that was developed for the UK government as part of the Stern Review on the Economics of Climate Change. If the higher value were used instead of the lower value, the impact of PV deployment on society would change in the Base Case from a loss of $2.2 billion to a gain of $590 million.

Based on the electricity system modeling conducted as part of the Solar Study, the total CO_2 emission from the New York electric generation sector will be approximately 34 million metric tons in 2025. The deployment modeled in the Solar Study will achieve 1.7 million metric tons of reductions in that year, or roughly 5% of the total projected emissions. The installation of 5,000 MW of PV will therefore contribute New York's overall climate action goals, but a broader portfolio of climate action strategies will be required if the state seeks to achieve the 80 by 50 greenhouse gas emission reduction goal[11].

7.1.2. Sulfur Dioxide, Nitrogen Oxides, and Mercury

The total amount of SO_2, NO_X and mercury emissions that PV would displace over the course of the study period is contained in Table ES-4 below. The table also contains the total value of each of the emissions reductions. SO_2, NO_X, and mercury were valued at $3,500/ton, 1,100/ton and $195 million / ton, respectively, based on health benefits only. These values do not monetize ecosystem benefits, such as reductions in acidification of lakes, streams and forests, or eutrophication of estuaries and coastal waters.

Table ES-4. Net Present Value of Emissions Reductions

Air Pollutant	Total amount	Net present value of emissions reductions (millions)
SO_2 (tons)	67,000	$24
NO_x (tons)	33,000	$97
Mercury (pounds)	120	$13

The total value of these emissions reductions over the study period is $130 million. Incorporating this value into the calculation of PV deployment's cost to society would reduce the total losses in the Base Case from $2.2 billion to $2.1 billion.

Table ES-5 below lists the total amount of NO_X, SO_2, and mercury emission projected for 2025 and as well as the corresponding emissions reductions associated with PV deployment. As can be seen in the Table, PV deployment will have the greatest impact on the total amount of SO_2 emissions.

11 Executive Order 24 in August 2009 formally established a New York State goal of reducing GHG emissions 80 percent below 1990 levels by 2050 (or 80 by 50), See the New York State Climate Action Plan Interim Report - November 9, 2010. http://nyclimatechange.us/

Table ES-5. Projected Emissions Reductions

Fuel type	Emissions in 2025 (tons)	Emissions reduced by PV in 2025 (tons)	% reduction in emissions in 2025
NO_X	24	0.9	4%
SO_2	15	2.5	16%
Mercury	0.04	0.002	6%

7.2. Land Use

Another important environmental consideration of PV is the land area used to install systems. Today nearly all PV installations in the Northeast are on roof tops or other structures. It is likely that the number of ground-mounted systems will increase, however, as New York scales up its PV market and looks to build systems that are too large for roof tops. Ground-mounted systems can be developed on land with little or no high-value alternative use ("brownfield sites"), such as capped landfills and contaminated sites. Other types of sites that may be attractive, and that have little or no competing value, include highway medians and inside-the-fence buffer zones (e.g. at substations, airports, power plants, transmission rights of way, etc.). It is likely that installations would also take place on sites with alternative uses ("greenfield sites") if New York were to scale up to meet a 5,000 MW target. The use of greenfield sites for PV installations has a potentially negative impact on the environment. The Solar Study assumes that, on average, one megawatt of PV requires five acres of space.[12]

There are approximately 30 million acres of land in New York State. If the entire 5,000 MW of PV were ground-mounted, it would require 23,000 acres, or approximately 0.08% of the total land available. Three land use scenarios were developed to test the likely impact of PV deployment on greenfield sites. The base PV scenario assumes that PV is installed in the state in a way that reflects current load distribution. The two other scenarios assume a greater number of systems installed in downstate areas (with a greater number of on-roof and brownfield installations) and a greater number of systems installed in upstate areas, where greenfield sites would be more prevalent. Table ES-6 below shows the estimated amount of greenfield space required under each scenario. The total impact is small, ranging from under 0.01% to 0.02% of New York land area.

Table ES-6. Land Use Impacts

Deployment	Acres of greenfield land used	% of state total land
Base deployment	3,000	0.01%
Greater downstate deployment (Alternative A)	2,600	0.009%
Greater upstate deployment (Alternative B)	6,000	0.02%

These scenarios illustrate that PV can be deployed in ways that have different implications for land use and open

12 This figure is based on reports from secondary sources as well as interviews with and surveys of installers familiar with ground-mounted installations.

space. Land use impacts can be minimized by focusing development in downstate areas. A focus on development downstate is consistent with the finding that downstate areas (e.g. New York City) will experience grid parity first and will therefore create the most cost-effective opportunities for PV deployment. New York State, for example, has already begun to target downstate areas through programs such as the RPS regional competitive bidding program.

8. PV POLICIES

Key Findings:

- A comprehensive approach to PV deployment will likely include cash incentives as well as low-cost or no-cost complementary regulations such as streamlined permitting, interconnection standards, and building construction mandates that can reduce the installed cost of PV and drive demand.
- There is a range of policy incentive mechanisms that can be used for PV deployment, such as upfront payments, standard offer performance-based incentives, and quantity obligations. Although each of these mechanisms has different characteristics, the salient differences between policy types can be reduced through policy design. Even so, there are fundamental differences in terms of overall policy cost, investor security, and implementation.
- Renewable Energy Credits (RECs) are a policy tool that can be combined with most other policy mechanisms. RECs that are traded on spot markets and are not supported by long-term contracts or price floors, however, are challenging to finance and increase the investor risk, and therefore, the cost, of quantity obligations.
- The longer the term for a PV incentive, the lower the $/kWh payment needs to be. Therefore, longer-term payments create the opportunity for PV to reach parity faster.
- Incentive rates can be set administratively or through competitive processes. Competitive processes are consistent with New York's competitive electricity market, although they may create barriers to entry for smaller and less sophisticated market participants. Competitive processes can be used for larger projects, whereas administratively-determined incentives can be used to target smaller projects.

In exploring policies to achieve 5,000 MW of PV by 2025, New York has an opportunity to learn from its own experience and from the experience of other states and countries. Broadly, policy mechanisms can be categorized as incentives and regulations. Incentives include policies that address economic and financial barriers to PV, such as rebates and tax credits, whereas regulations are policies that address non-economic barriers, such as interconnection standards and streamlined permitting. Incentives are currently the primary driver of PV markets, but regulations can accelerate adoption and lower PV system costs. Streamlined permitting and best practice interconnection standards, for example, can lower PV development costs, whereas workforce training programs could lower the cost of installations. Table ES-7 below provides examples of incentives and regulations, a number of which are used in concert to provide a comprehensive approach to support the deployment of PV.

Table ES-7. PV Incentives and Regulations

PV INCENTIVES	PV REGULATIONS
Performance-based incentives	Streamlined permitting
Rebates / grants	PV building requirements
State tax credits	Improved or uniform interconnection standards
State tax exemptions	Net metering[13]
Industry recruitment and support	PV access and PV rights laws
State PV loan programs	Community PV regulations
PACE[14] financing	
On-bill financing	
Loan guarantees	

Although PV currently requires incentives due to the technology's above-market cost, regulations such as mandates requiring PV in new construction may be sufficient to support market growth in the future when PV reaches price parity with electricity from the grid.

The analysis focuses initially on three categories of incentives: standard offer performance-based incentives, upfront payments, and renewable energy quantity obligations. The structure and design variations of these incentives is discussed in detail in the body of the Study and benchmarked against national and international experience. Each of these three policy types is also qualitatively assessed from the ratepayer, investor and policy maker perspectives. It is important to note that the Study does not recommend one policy type over another. Instead, the emphasis of the policy review is to identify lessons learned that can be expanded as New York contemplates the appropriate policies.

Standard offer performance-based incentives (PBIs) provide PV projects with a payment for each kWh generated for a set number of years. The PBIs are set ahead of time and available on a first come, first-served basis. Standard offer PBIs are one of the most prevalent forms of PV support around the world and have supported the majority of the world's PV systems. Examples of standard offer PBIs include California's incentives for PV systems larger than 30 kW, Vermont's SPEED standard offer program, and feed-in tariff policies in European countries such as Germany and Spain.

13 Depending on how defined net metering can have elements of both incentives and regulations.

14 Property Assessed Clean Energy financing, or PACE, is a local government financing tool that allows municipal governments to lend funds to property owners and collect re-payments through property tax bills. PACE financing programs have been implemented in a number of municipalities; however, a 2010 decision by the Federal Housing Finance Administration (FHFA) has limited the expansion of PACE programs for residential property owners.

Standard offer PBIs can lower investor risk and the costs of financing by providing PV projects with a known payment stream. Standard offer PBIs can also encourage those with smaller projects to participate since there are few barriers to participate in the incentive program. While PBIs have their advantages, it can be challenging to set the right payment rate that is attractive for PV generators. Standard offer PBIs also do not encourage project-on-project competition. Moreover, the ability of standard offer PBIs to lower investment risk and attract a broad range of participants means that the market can grow rapidly. Rapid market growth can be a challenge if not anticipated and managed correctly. Table ES-8 below summarizes the strengths and limitations of standard offer PBIs from the perspective of ratepayer, investors, and policymakers.

Table ES-8. Strengths and Limitations of Standard Offer PBI

Ratepayer perspective	Investor perspective	Policymaker perspective
STRENGTHS • Low investor risk = low costs of capital and decreased policy costs • Payment based on performance • Long-term, fixed price contract can serve as a hedge against rising energy prices LIMITATIONS • Rates can be set "too high" • No automatic adjustment for changes in market prices	STRENGTHS • Revenue certainty and security • Standard offer lowers transaction cost and development risk • Allows smaller projects to participate LIMITATIONS • A large market response can limit policy durability if not adequately managed	STRENGTHS • Lower policy costs • Easily targeted for specific project types LIMITATIONS • Challenging to get the rate right • Purchase requirement on distribution utilities is new for NY • No project-on-project competition

Lessons learned: Standard offer PBIs can create the conditions for rapid market growth for a broad range of project types and sizes. In Germany, for example, over 7 GW of PV was installed in 2010 and again in 2011. The majority of these projects have been rooftop systems below one MW in size. Germany projects that it will reach over 51,000 MW by 2020. In order to contain the cost of market growth, Germany's PV PBI rate decreases annually, and the government has also intervened in the middle of the last several years to introduce additional reductions. The German market has maintained momentum through 2010 despite rapid expansion. Spain, by contrast, unexpectedly installed 2,800 MW of PV under a generous standard offer PBI in 2008. In reaction to this growth, Spain capped its markets and dropped its rates in a way that curtailed market growth and shook investor confidence. A key lesson learned is that standard offer PBIs should have clear goals and volume management strategies established at the outset.

Standard offer upfront payments include both grants (payments at the time of purchase) and rebates (payments that are made once the installation is complete). They are similar to PBIs in that their levels are set and known in advance and they are available on a first-come, first-served basis. The primary difference from PBIs is that they are paid at the outset of a project, rather than over time. Most upfront payments are also based on the installed capacity of the system (e.g. $/kW). Seventeen states, including New York, currently have programs that support PV through upfront payments. To date, approximately $2.942 billion has been spent across the United States through state rebate or grant programs, supporting over 1,300 MW of PV capacity.

The strengths and limitations of upfront payments are similar to those of PBIs: they lower investor risk by providing a known amount of revenue and enable smaller projects to participate if offered on a first-come, first-served basis, but, it can be challenging to set upfront payments at the right level.

A key difference is that upfront payments do not necessarily create incentives for performance, although they can be linked to the expected or initial performance of the system. It is also important to note that rebates may be more cost-effective for ratepayers than PBIs because they provide PV projects with their required return in a shorter period of time. Nevertheless, the rate impact of having the incentive payments front-loaded instead of spread out over time may be challenging for ratepayers. The strengths and limitations of upfront payments are summarized in Table ES-9 below.

Table ES-9. Strengths and Limitations of Standard Offer Upfront Payments

Ratepayer perspective	Investor perspective	Policymaker perspective
STRENGTHS • Upfront payments can provide PV projects with the return they require more cost-effectively than PBIs LIMITATIONS • The rate shock of initial payment for a large volume of installations can be high • Rates can be set too high	STRENGTHS • Revenue certainty and security • Standard offer lowers transaction cost and development risk • Allows smaller projects to participate LIMITATIONS • A large market response can limit policy durability if not adequately managed	STRENGTHS • Can be useful for early adoption in order to persuade innovators to enter market LIMITATIONS • Challenging to get the rate right • Typically requires source of funding (e.g. SBC) and a fund, which can be subject to political risk • Not performance based

Lessons learned: Most U.S. states have used upfront payments to jump-start their PV markets and many states continue to use rebate programs as the primary mechanism for supporting PV growth. As PV markets have matured, however, an increasing number of states have transitioned to PV-specific renewable energy quantity obligations supported by REC markets (see below). A key argument for this transition in states such as New Jersey has been that the ratepayer impact of rebates would be unsustainable at the scales anticipated under the renewable energy quantity obligations. It has been acknowledged, however, that smaller-scale systems may not be well equipped to compete in REC markets. As a result, some states such as Massachusetts have continued to provide upfront payments to smaller-scale systems while requiring larger-scale systems to participate in the REC markets. A key lesson learned is that upfront payments may not be well-suited to be the sole mechanism used to achieve 5,000 MW by 2025, but they could be used in tandem with other incentives to support smaller-scale projects that might otherwise “fall through the cracks.”

Renewable energy quantity obligations set mandatory targets for PV. Utilities (or other entities) are responsible for purchasing RECs in order to demonstrate compliance with the quantity obligation targets. RECs are typically procured through a short-term or “spot” market or through a bidding process (e.g. auctions and RFPs) in which PV projects are awarded long-term purchase contracts.[15] Sixteen states, plus Washington D.C., have established targets to specifically support PV and/or distributed generation. Similarly, New York has specific policies to target PV under its RPS.

The strengths of quantity obligations are that they encourage competition between PV projects and favor least cost projects. The limitations of quantity obligations differ depending on whether the policy relies exclusively on short-term REC trading or whether long-term contracts are available. Short-term REC trading can lead to uncertain revenues from PV projects and can make them difficult and expensive to finance. Competitive bidding can eliminate the problem of uncertain payment streams by awarding PV projects long-term contracts. Still, not all PV projects have enough money and sophistication to effectively compete for long-term contracts. As a result, competitive bidding can serve as a barrier to smaller-scale projects. The strengths and limitations of quantity obligations are summarized in Table ES-10 below.

Table ES-10. Strengths and Limitations of Quantity Obligations

Ratepayer perspective	Investor perspective	Policymaker perspective
STRENGTHS • Favors least cost projects • Competition encourages lower costs LIMITATIONS • Prices can be inflated by investor risk premiums (if no long-term contracts) • Market prices can spike during REC shortage	STRENGTHS • Creates demand and a market • Supports financing (if long-term contracts, price floors, etc.) LIMITATIONS • Price volatility hampers financing (if no long-term contracts) • Policy changes can impact market prices and project revenue	STRENGTHS • Low administrative burden for spot market trading • Fits restructured markets • Quantity of supply known in advance • Competitively neutral LIMITATIONS • Unknown cost • Can create barriers for emerging technologies or smaller projects

15 New York’s RPS policy is an example of a quantity obligation. New York’s RPS Main Tier procurement is unique because its competitive procurement is organized by the state rather than by individual utilities and because renewable energy attributes are procured under contract instead of electricity and/or RECs.

Lessons learned: To date, the performance of PV quantity obligations has been mixed. REC prices in markets that rely on spot market trading have been volatile. This price volatility has negatively impacted existing projects and has made it challenging and expensive for new projects to secure financing. In order to alleviate concerns over REC price volatility, several states that rely on REC trading have introduced mechanisms such as price floors, loan programs, and competitive bidding for long-term contracts in order to provide security for the market. A key lesson learned is that quantity obligations for PV require some type of mechanism to reduce or eliminate REC market price volatility in order to support cost-effective financing.

The incentive types described above (standard offer PBIs, standard offer upfront payments, and renewable energy quantity obligations) are intended to serve as illustrative examples and benchmarks and they do not necessarily represent the full universe of possible policies that New York could implement. The policy mechanisms should also not be considered mutually exclusive. First, the limitations of each policy can be addressed using a variety of different policy designs that can effectively blur the salient difference between the policy mechanisms. Second, each of the policy mechanisms (and their variations) can be combined and implemented as hybrid policies, which are discussed in greater detail in the next section.

The New York regional competitive bidding PV incentive program illustrates how different incentive types can be combined in new or hybrid forms. The program has elements of upfront payments in that it is paid partially once the project is installed; however, the mechanism seeks to mitigate some of the limitations of upfront rebates by linking full payment to PV system performance over the first three years of operation. The program also awards the payments on a competitive basis, rather than as a standard offer.

9. MODELING OF POLICY MECHANISMS

Key Findings:

- The difference in ratepayer impact among the three least expensive policy mechanisms is less than 17%, which is potentially smaller than the impact of specific design choices including targeting deployment to specific installation types and locations.
- An upfront payment incentive for smaller customers (and central procurement for larger customers) similar to the policy approach used in New York for the RPS is the least expensive mechanism analyzed as part of the Solar Study.
- A quantity obligation with price floor (similar to the policies in neighboring states) is projected to cost 50% more than the least cost policy mechanism.

- Many complementary policies could be implemented at low or no overall cost in parallel with the analyzed incentive polices, on either a local or state-wide basis, potentially reducing the cost of and removing barriers to reaching the targets, and should therefore be considered as New York refines its solar policies.

- Costs to compete for and potentially negotiate a contract could be prohibitive for smaller-scale generators.

- The choice of policy mechanisms that reduce investor risk and administrative and transaction costs will have lower peak and average direct and net impacts on ratepayers.

Based on the qualitative analysis of different policies conducted in the previous section, a subset of policies was selected for quantitative analysis in order to determine how changes in the policy might alter the impacts of the 5,000 MW Goal. Many of the impacts discussed in this Study, such as the environmental benefits and the electricity price suppression effect depend on the total amount of capacity installed and do not vary with policy types. Different policies can have different ratepayer impacts, however, depending on the policy mechanisms chosen and their designs.

For the purpose of the quantitative analysis, four policy mechanisms were selected from a broad suite of options for additional modeling. The criteria used to select these mechanisms included:

- **The level of investor security that they create**. As detailed in the comparison of PV policies, incentives that provide a stable, long-term revenue stream provide the highest level of investor security. Incentives with values that vary over time are perceived to be the most risky. Creating investor security is important because it lowers the costs of financing projects and therefore, overall policy costs. Quantity obligations that rely only on spot market REC trading were not selected for further analysis because they do not provide projects with certain revenues and they create a high degree of risk. This decision was reinforced by recent REC market price volatility in neighboring markets. Quantity obligations were only considered if they included a mechanism to create certain revenues, such as a price floor for tradable RECs or long-term contracts.

- **The cost of taking advantage of the incentive**. Some incentives, such as upfront payments and standard offer PBIs, are easy for PV projects to take advantage of because they are known in advance and available on a first-come, first-served basis. Other incentives, however, require a higher degree of sophistication and cost to access. Competitive procurements, for example, require PV projects to prepare and submit bids and applications without the guarantee of winning. Since not all projects can afford the costs of participation in these competitions (for example, due to transaction costs), they serve as a barrier, particularly for smaller-scale projects. In order to reflect the objective of supporting a diversity of system sizes in New York, it was determined that some of the modeled policies should have features which encouraged broad market participation.

- **The need for competitive pressure on PV system prices.** Encouraging project-on-project competition not only places downward pressure on PV prices, but is also consistent with the competitive and deregulated electricity market environment in New York. Quantity obligations with tradable RECs or competitive bidding create competition between projects. As a result, some form of quantity obligation was incorporated into each of the four policy mechanisms selected for additional modeling.

The four policy mechanisms selected for additional modeling include:

- **A PV quantity obligation with a price floor** ("QO w/ price floor"). This option assumes that a QO is the primary policy mechanism that supports all system sizes under the 5,000 MW PV scenario. The QO uses REC spot market trading, but the prices are supported by a long-term price floor that provides a greater degree of revenue certainty to project developers and investors. This model is similar to the approaches adopted in neighboring states.

- **An auction for long-term contracts managed by the electric distribution companies (EDCs)** ("EDC LT Contract Auction")**.** This assumes that the state EDCs will manage a competitive procurement for all PV project sizes, under which they will award long-term contracts to purchase renewable energy from winning bidders. This approach is similar to the competitive auction for renewable energy that was recently adopted in California (e.g. the Reverse Auction Mechanism).

- **The current RPS approach with a PV carve-out for the Main Tier: rebates for small PV systems and the current RPS procurement approach for large projects** ("Hybrid A"). Since this option represents a hybrid of two different types of policy mechanism, it is referred to as "Hybrid A." Hybrid A assumes that the current New York RPS central procurement mechanism is expanded to specifically target large-scale PV systems. Since competitive bidding may serve as a barrier to smaller-scale projects, however, Hybrid A also assumes that rebates will be available on a first-come, first-served basis to smaller-scale projects. This approach is similar to the existing New York RPS policy since it combines elements of both the main tier procurement and the rebates available through the Customer-Sited Tier.

- **A policy that combines standard offer PBIs for small systems with auctions for long-term contracts for large systems** ("Hybrid B"). This option combines two distinct policy mechanisms and is therefore referred to as "Hybrid B". Similar to Hybrid A, Hybrid B assumes a competitive procurement for large projects and a standard offer incentive for smaller systems. Under Hybrid B, however, the standard offer incentive is a PBI, rather than an upfront payment. Also, the auctions for long-term contracts under Hybrid B are managed by the EDCs, instead of being managed centrally by the state. This is similar to approaches under consideration in the State Legislature.

The modeling results for the comparative ratepayer impacts of the different policies are contained in Figure ES-14 below. The quantity obligation with a price floor has the highest direct ratepayer impact at $4.5 billion (NPV) over the full policy period (2013 – 2049). The policy mechanism with the lowest ratepayer impact ($3 billion) is Hybrid A, which combines a rebate with competitive procurement. A primary driver for the quantitative differences between models is the cost of financing, which is assumed to be highest for the quantity obligations because the price floor removes some, but not all, of the projects revenue risk. It is important to note, however, that although the comparison below focuses on rate impact, policy mechanisms should be judged and selected based on the consideration of multiple criteria beyond rate impact alone.

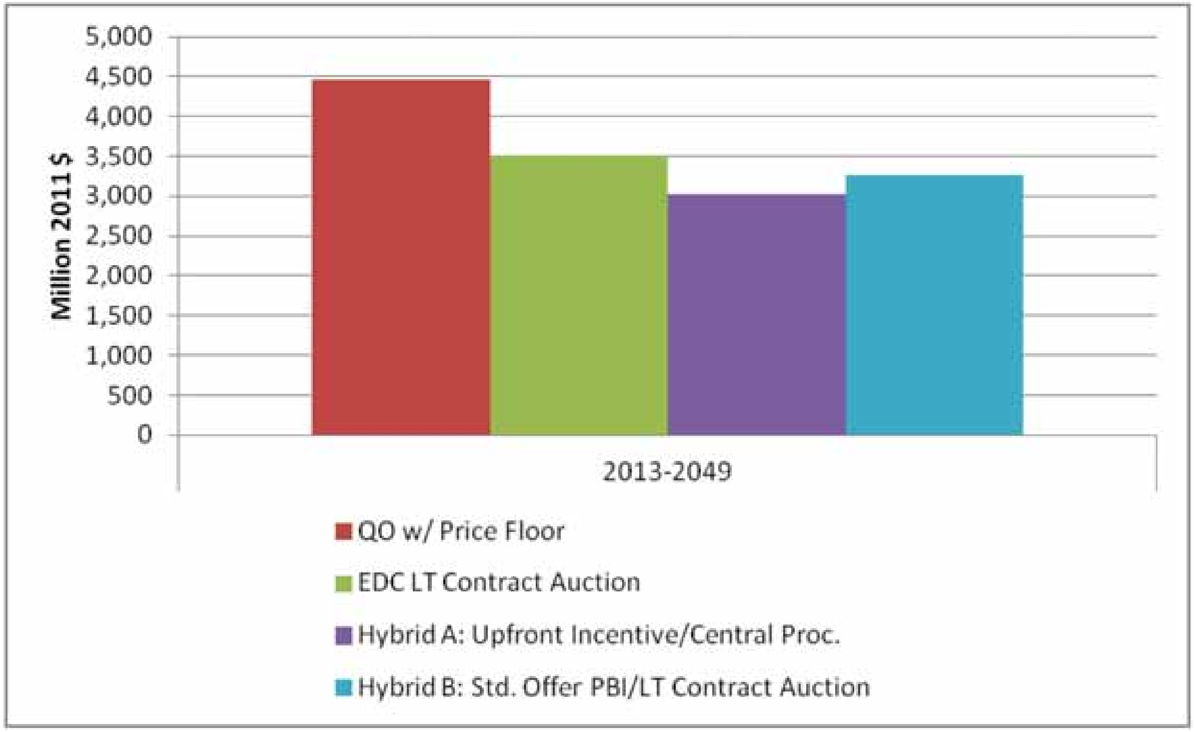


Figure ES-14. Net Ratepayer Impacts of Policy Options

A second important driver for the quantitative differences between the policies is the fact that Hybrid A uses rebates for a significant proportion of the policy. As can be seen in Figure ES-15 below, the use of rebates causes a higher initial ratepayer impact than the other policies. In 2013, for example, Hybrid A would account for 0.5% of total electricity bills, whereas the other three policy mechanisms would account for under 0.2%. By the time the last rebates are paid in 2025, however, the share of Hybrid A in state electricity bills drops off rapidly, as only the payments needed to cover the long-term contracts remain. Although their initial cost is lower, the other three policies would each account for a greater share of electricity bills in 2025. The ratepayer impact calculation includes consideration of both the cost of net metering to ratepayers that do not participate in the program as well as the electricity price reduction effect of PV. From 2016-2018, the electricity price reduction effect actually creates ratepayer savings, rather than ratepayer costs. This impact is temporary, however, and cannot fully offset the costs of PV deployment.

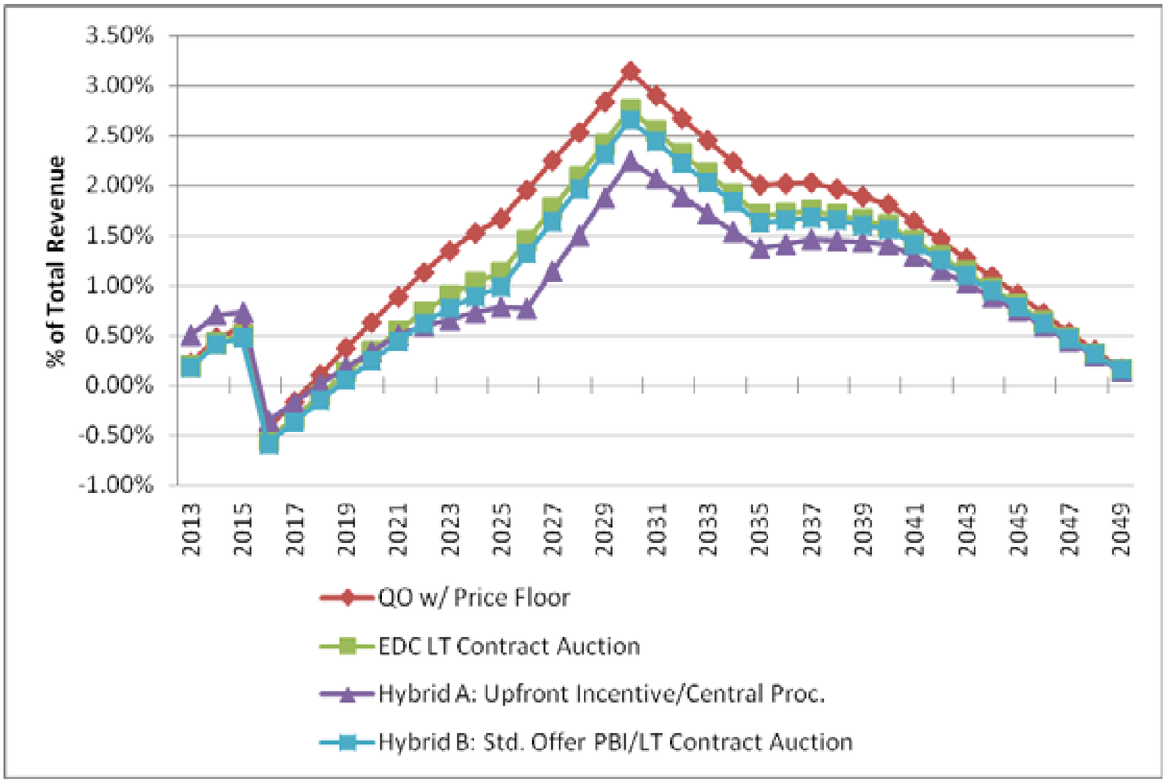


Figure ES-15. Net Annual Ratepayer Impacts of Policy Options as a Percent of Total Revenue

10. CONCLUSIONS

The Solar Study analyzed a broad range of benefits and costs in order to assess the impact of meeting a 5000 MW by 2025 Goal. The Solar Study also described strengths and limitations associated with policy mechanisms that could be used to reach such a target and provided recommendations should any mechanism be pursued. The following summarizes the key findings of the Solar Study:

- PV Deployment Scenario
    - The pace of annual PV capacity additions drives the timing and magnitude of annual rate impacts, employment impacts, costs, and benefits. As such, the pace of PV development is a central component of any PV policy design. Policymakers should therefore consider the actual cost of annual development in establishing policy targets, so as to craft a flexible and responsive policy.
- New York in the Global PV Market
    - The global PV market has recently seen dramatic declines in PV panel prices.

- These declines have benefited New York, with installed costs dropping significantly in the past three years.
- The existing global supply chain could adequately meet the needs of New York's market as it grows towards a 5,000 MW target.

- NYS Renewable Energy Policy Context
  - New York has aggressive renewable energy goals and robust policies that support those goals.
  - Current New York policies support a range of renewable technologies including several high-cost early-stage generation sources, like PV, that have the potential to reach significant market penetration as costs decline.
  - New York has taken a holistic approach to development of a robust renewable energy market, including PV, through workforce development as well as technology and business development initiatives.
  - Existing PV programs in New York have stimulated a stable and growing market, but this market is small in relation to other East Coast markets.

- PV Cost Projections
  - By 2025, the cost of PV is expected to decline significantly, where the Base Case installed cost will range from $2.50 per W for MW-scale systems to $3.10 per W for the residential-scale system, in nominal dollars. For the Low Cost Case, the range is $1.40 per W to $2.00 per W and for the High Cost Case the range is $2.90 per W to $4.30 per W.
  - PV is not expected to achieve wholesale parity during the analysis period (2013 thru 2049) in any cost future.
  - Retail parity may be achieved, and will occur sooner in New York City than in other regions of the state. This suggests a greater leverage of state PV incentive dollars in New York City. In a low-cost future there is parity in New York City by 2017.
  - PV cost of energy is expected to be more expensive than large-scale onshore wind energy and will most likely be more expensive than offshore wind in 2025.
  - PV cost of energy may be competitive with small-scale wind energy and greenfield biomass technologies by 2025.
  - Due to the differences between what is measured by cost of electricity and by the value of the energy produced, it is recommended that a full study of the costs and benefits of other renewable energy technologies be conducted to better inform renewable energy policy development.
  - Continued federal incentives will play a critical role in the magnitude and predictability of future PV prices. In addition, the SunShot goal articulated by the U.S. DOE is an aggressive and meritorious goal

that, if achieved, would substantially reduce PV cost and change the benefit-cost equation. It is recommended that New York should strongly support continued federal incentives and aggressive federal research efforts to reduce the cost of PV to consumers.

- Benefit-Cost Analysis
  - Future cost of PV and the federal incentive level were the primary drivers of total cost of reaching the Goal, while the location of installations and system sizes were secondary cost drivers.
  - Price suppression and avoided electricity production costs were the greatest drivers of benefits, while other factors, including reduction in air pollution, reduction in the use of fossil fuels, avoided distribution system upgrades, and avoided line losses showed smaller benefits.
  - Under the Base Case scenario, reaching the 5,000 MW Goal had a net cost for New York of $2 billion.
  - Under the Low Cost Case scenario, reaching the 5,000 MW Goal had a net benefit for New York of $2 billion.
  - Under the High Cost Case scenario, reaching the 5,000 MW Goal had a net cost for New York of $8 billion.
  - Increased deployment of PV downstate had a higher benefit-cost ratio, lowering the overall costs of meeting the Goal by nearly $1 billion, as electricity costs are higher in the New York City region.

- Jobs and Macroeconomic Impact
  - Analysis conducted looked at the overall impacts to the New York job market, taking into consideration the jobs gained in the solar industry and elsewhere, as well as the potential job loss due to the costs imposed on the economy by the Goal.
  - In terms of the total impact of the Base Case PV deployment on the economy, there will be no economy-wide net job gain; in fact, modeling showed an economy-wide net job loss of 750 jobs because of the impact of increased electricity rates needed to pay for the PV program. Gross State Product (GSP) would be reduced by $3 billion between 2013 and 2049, representing a small annual decrease in GSP of less than 0.1%.
  - Deployment to a level of 5,000 MW will create approximately 2,300 direct PV jobs associated with PV installation for the installation period (2013–2025) and an average of approximately 240 direct jobs associated with Operations and Maintenance (O&M) from 2025–2049.
  - There will also be 600 jobs lost for the study period primarily as a result of the reduced need to expand and upgrade the distribution grid, a reduced need for conventional power plants, and reductions in in-state biomass fuel production.
  - The sensitivity analysis demonstrates that a Low Cost Case future would lead to economic growth, including the creation of 700 economy-wide net jobs and an additional $3 billion in GSP, while a High Cost Case future would lead to a reduction in GSP of $9 billion and on the order of 2,500 economy-wide net job losses.

- Subsidies at the scale required to achieve 5000 MW of PV by 2025 would most likely have a small net-negative impact on the economy; however, continued support for PV is warranted given the promise of a low-cost PV future.

- Retail Rate Impacts
  - The net impact of the PV deployment on electricity bills takes into account the above-market costs of PV, the costs of net metering, and the savings generated by the suppression of wholesale electricity prices.
  - The net impact of these factors on retail electricity rates is $3 billion over the study period, or approximately 1% of total electricity bills. In any given year, this rate impact could be as much as 3% of total electricity bills.
  - Analyses of Low Cost and High Cost scenarios were also conducted. The impact of the Low Cost scenario is approximately $300 million in additional ratepayer impacts or 0.1% of total bills (annually a maximum of 1%), whereas the impact under the High Cost scenario would be $9 billion or 2.4% of total bills (annually a maximum of 5%).
  - An analysis was also conducted to determine the effect of higher natural gas prices on PV deployment. Higher natural gas prices would reduce the above-market cost of PV and lower the retail rate impact to 0.6% of total electricity bills (annually a maximum of 2%) instead of 1%.
  - Since retail rates are higher in Southeast New York, PV is closest to grid parity downstate. Concentrating smaller-scale PV installations downstate would result in lower overall retail rate impacts.
- Environmental Impacts
  - Over the study period (2013–2049) PV will reduce fossil fuel consumption by 1,100 trillion Btus (TBtus). This includes a 7% reduction in the use of natural gas, a 4% reduction in the use of coal, and a 40% reduction in the use of oil in the electricity sector in 2025.
  - This reduction will lower carbon dioxide (CO_2) emissions by 47 million tons, equivalent to taking an average of approximately 250,000 cars off the road for each year of the study period. The CO_2 emissions reduction is valued at $450 million for the Base Case.
  - A high valuation for CO_2 emission reduction values the 47 million tons at $3.2 billion and has a significant enough benefit to make the Base Case net-beneficial to New York.
  - The amount of CO_2 reduction remains small compared to the total reduction that was identified for the power generation sector in the New York State Climate Action Plan Interim Report. In 2025, PV will reduce emissions by 1.7 million metric tons, or 5% of the emissions from the electric generation sector in that year.

- The reduction in fossil fuel use will lower nitrogen oxides (NO_x) by 33,000 tons, sulfur dioxide (SO_2) by 67,000 tons and mercury by 120 pounds. The net present value of this combined reduction is $130 million over the study period. This valuation is based on health benefits only, and does not attempt to monetize ecosystem benefits (such as reduction in acidification of lakes, streams and forests, and eutrophication of estuaries and coastal waters).
- In 2025, PV will reduce total NO_x emissions by 4%, total SO_2 emissions by 17%, and total mercury emissions by 6%.
- PV could also require land for site systems. It is estimated that 5,000 MW of PV would require 23,000 acres of land if the entire amount were ground-mounted. Still, there is a significant amount of roof space available, as well as areas such as brownfield sites, existing power plant sites, and parking lots where PV could be deployed without using land that could have other productive uses. In total, it is estimated that PV would require from 2,600–6,000 acres of greenfield space total, which is less than 0.02% of total state land area.

- PV Policies
  - A comprehensive approach to PV deployment will likely include cash incentives as well as low-cost or no-cost complementary regulations such as streamlined permitting, interconnection standards, and building construction mandates that can reduce the installed cost of PV and drive demand.
  - There is a range of policy incentive mechanisms that can be used for PV deployment, such as upfront payments, standard offer performance-based incentives, and quantity obligations. Although each of these mechanisms has different characteristics, the salient differences between policy types can be reduced through policy design. Even so, there are fundamental differences in terms of overall policy cost, investor security, and implementation.
  - Renewable Energy Credits (RECs) are a policy tool that can be combined with most other policy mechanisms. RECs that are traded on spot markets and are not supported by long-term contracts or price floors, however, are challenging to finance and increase the investor risk, and therefore, the cost, of quantity obligations.
  - The longer the term for a PV incentive, the lower the $/kWh payment needs to be. Therefore, longer-term payments create the opportunity for PV to reach parity faster.
  - Incentive rates can be set administratively or through competitive processes. Competitive processes are consistent with New York's competitive electricity market, although they may create barriers to entry for smaller and less sophisticated market participants. Competitive processes can be used for larger projects, whereas administratively determined incentives can be used to target smaller projects.

- Modeling of Policy Mechanisms
    - The difference in ratepayer impact among the three least expensive policy mechanisms is less than 17%, which is potentially smaller than the impact of specific design choices including targeting deployment to specific installation types and locations.
    - An upfront payment incentive for smaller customers (and central procurement for larger customers) similar to the policy approach used in New York for the RPS is the least expensive mechanism analyzed as part of the Solar Study.
    - A quantity obligation with price floor (similar to the policies in neighboring states) is projected to cost 50% more than the least cost policy mechanism.
    - Many complementary policies could be implemented at low or no overall cost in parallel with the analyzed incentive polices, on either a local or state-wide basis, potentially reducing the cost of and removing barriers to reaching the targets, and should therefore be considered as New York refines its solar policies.
    - Costs to compete for and potentially negotiate a contract could be prohibitive for smaller-scale generators.
    - The choice of policy mechanisms that reduce investor risk and administrative and transaction costs will have lower peak and average direct and net impacts on ratepayers.

1. INTRODUCTION

1.1. The Power New York Act of 2011

On August 4, 2011, the *Power New York Act of 2011* (the Act) was signed into law[1] (Governor's Press Office, 2011). Section 22 of this Act included a 2012 Study to Increase Generation from Photovoltaic Devices in New York (the Solar Study). While the current contribution of solar photovoltaic (PV) energy generation is small and the cost of the technology is at a premium compared with market electricity prices, the Act sought analysis of the benefits and costs of PV, acknowledging that costs are declining and noting the potential for PV energy generation to contribute to economic development and job creation in the State.

The Act directed NYSERDA to conduct, in consultation with the Department of Public Service (DPS), a study regarding policy options that could be used to achieve goals (the Goals) of 2,500 MW of installed capacity operating by 2020 and 5,000 MW operating by 2025. The Act called for NYSERDA to report to the Governor and the legislature on or before January 31, 2012 regarding the Solar Study's findings and recommendations. Specifically, the Act directed that the Solar Study should:

- Identify administrative and policy options that could be used to achieve the Goals
- Estimate the per-megawatt cost of achieving increased generation from PV devices and the costs of achieving the Goals using the options identified in the analysis
- Analyze the net economic and job creation benefits of achieving the Goals using each of the options identified in the analysis
- Conduct an analysis of the environmental benefits of achieving the Goals using the options identified in the analysis.

During the Fall of 2011, NYSERDA contracted and worked closely with Sustainable Energy Advantage, LLC, and its subcontractors, La Capra Associates, Inc., Economic Development Research Group, Inc. and Meister Consultants Group to conduct the Solar Study. The analysis includes input from a range of New York PV policy stakeholders including staff from the DPS, the New York Power Authority (NYPA), and the Long Island Power Authority (LIPA). The following report describes the results of this analysis, satisfying the legislated requirements of the Act.

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1 Chapter 388 of the Laws of New York, 2011

1.2. Study Structure and Approach

To address the objectives outlined in Section 1.1, this study performed a number of tasks, which are presented as follows:

- Section 1.3 includes a summary of existing New York State Renewable Portfolio Standard (RPS) and other PV policies and programs currently in effect, and provides background information on historic PV market, technology and cost trends in New York and globally
- Chapter 3 develops and describes alternative forecasts of PV installed and operating cost, and the development of alternative PV levelized cost of energy trends used to assess costs of meeting the Act's PV targets. It also compares New York specific PV costs with the costs of other renewable energy technologies
- Chapter 4 describes three scenarios that were developed to examine impacts of alternative deployments of PV development in New York across different installation sizes and locations in meeting the Act's targets
- Chapters 5, 6 and 7 present analyses of the direct costs and benefits, net jobs and macroeconomic analysis, and retail rate impacts, respectively, associated with increasing deployment of PV in New York to meet the Act's targets. Chapter 8 summarizes the environmental impacts associated with increased PV deployment[2]
- Chapter 9 identifies and describes the salient features of policies, including incentives and regulations, used to support PV. It includes discussions of policy best practices, cost control mechanisms, and lessons learned from three solar policy case studies highlighting experiences in Germany, Spain and New Jersey. Chapter 10 describes the selection and analysis of four policy mechanisms capable of being applied to meet the targets of the Act
- Chapter 11 summarizes the results and conclusions
- Finally, a series of appendices contain supporting background and detailed results.

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2 For this study all monetary values associated with costs and benefits are presented as a 'Net Present Value'. All Net Present Value (NPV) calculations in this report use a nominal 7.0% discount rate (which corresponds to a real discount rate of 5.1%). In the appendix to this chapter, NPVs are also shown using a lower discount rate of 4.35% and a higher discount rate of 12%.

This study has been conducted in parallel with analysis conducted for the State Energy Plan (SEP), and utilizes the SEP electricity system modeling platform.[3] The study's scope includes several levels of modeling, including:

- Spreadsheet-based analysis of PV quantities, costs, financing and direct economic benefits
- Electricity market impacts and environmental benefits utilizing the SEP model; and
- Net economic and job creation benefits utilizing the Regional Economic Models, Inc. (REMI) model.

A generic 'Base' PV Scenario was developed to assess the rate impacts, costs, benefits, environmental impacts and macroeconomic impacts of meeting the Act's targets.[4] Analyses were performed to explore the sensitivity of Base PV Scenario results to uncertainties such as future PV costs, Federal incentives, financing costs, energy prices, and installation deployment alternatives. Scenario analysis was also used to examine the potential rate impacts of different policy mechanisms that could be utilized to achieve the targets in the Act. The sensitivity analysis modeling cases are summarized in Table 1, while policy scenarios are summarized in Table 2.[5]

Table 1. Scenarios and Sensitivity Analyses Explored

Scenarios	Sensitivity Analyses
Reference Case Base PV Scenario* (for 5000 MW by 2025 Policy Target)	High PV Cost Future* Low PV Cost Future* Alternative Installation Deployment A Alternative Installation Deployment B High Energy Prices* Indian Point Continued Operation

3 The Integrated Planning Model ("IPM"), a production cost model maintained by ICF International, was used to simulate the operation of the New York electrical system and energy market.

4 The Base PV Scenario meet's the Act's target and trajectory (described in Chapter 4). It uses "base" PV levelized cost of energy, using the set of assumptions for installed cost, financing cost and available federal incentives described in Chapter 3, which is consistent with PV systems competing for a fixed revenue contract with a credit-worthy counterparty providing revenue certainty for the assumed economic life of the installation. The Base PV Scenario costs are intended to capture the cost of energy from installation of systems, and not the full cost of the policies that drive them, which include transaction and administrative costs (discussed in Chapter 10).

5 Those cases market with an asterisk (*) are subjected to net economic and job creation benefit analysis, in addition to a special case testing the sensitivity of macroeconomic results to the potential to increase (relative to the base case) the amount of PV system investment that can be fulfilled by New York manufacturing firms.

Table 2. Policy Scenarios Explored

Policy Scenarios to reach 5000 MW by 2025 Policy Target
Solar Quantity Obligation Using Tradable SRECs, with a Price Floor Mechanism
Auction for Long-Term Contracts by Electric Distribution Companies
Hybrid A: Upfront Incentives for Residential and Small Commercial & Industrial installations and extension of the New York Main Tier Central Procurement approach to Large Commercial & Industrial and MW-Scale installations
Hybrid B: Standard Offer performance-based incentives for Residential and Small Commercial & Industrial installations and Auctions for Long-Term Contracts for Large Commercial & Industrial and MW-Scale installations

1.2.1 Scope of this Study

The scope of the study outlined above was extensive, and provides the appropriate analysis to assess the relative value to New York of a 5000 MW PV policy target. The analysis does not address several issues that may be relevant to New York policy makers when considering the adoption of a specific PV policy. Some of the issues falling outside the scope of this study include:

- The study does not analyze the merits or impacts of a comprehensive renewable energy portfolio, and the relative benefits derived from contributions of PV to such a portfolio. PV options considered in isolation from the benefits and costs associated with other renewable energy options may not account for the full spectrum of policy objectives when considering renewable energy alternative scenarios.
- The study describes strengths and limitations associated with the different policy mechanisms and recommends additional considerations should any mechanism be pursued, but does not attempt to recommend a single policy or specify policy implementation details.
- To isolate the impact of a single policy, this study analyzes only the impact of achieving a 5,000 MW goal by 2025. This was necessary in order to isolate the impact of this policy for analysis purposes. The study does not measure the effects of transformation in the marketplace or demand for PV products outside the scope of the 5000 MW target; thus there are no PV systems were modeled as installed after reaching 2025, no PV systems were modeled as being replaced at the end of their assumed economic life, and no PV systems were assumed to continue producing electricity (albeit at a reduced level) after the end of their economic life. Incorporating these issues would present a number of analytical challenges. There is considerable uncertainty regarding predicting market dynamics more than 15 years into the future. In addition, further study is necessary to determine the degree to which new PV installations beyond 2025 should be attributed to the policies being studied. Among other

challenges would be the development of additional novel reference cases correlating to different cost and federal incentive futures.

- The report did not directly address the potential physical value of certain applications of PV on the New York power grid, including localized reliability impacts (such as supporting existing network conditions and/or affecting future grid planning and operating resources) and how such applications may be enabled by targeted PV deployments.
- The study calculates the levelized cost of energy of PV as well as other renewable energy technologies. While the value (e.g.: displacement of expensive on-peak energy, and avoided line-loss through production of power at the point of use) of PV is calculated, the corresponding value for electricity production from other renewable energy technologies,, is beyond the scope of the study. Such an analysis would be required for an ‘apples-to-apples’ comparison.
- The administrative and transaction costs associated with the four selected policy mechanisms were not subjected to detailed analysis, in part because these factors would depend on design and implementation details that were beyond the scope of this study.
- For this analysis it was assumed that the economic life of PV system is 25 years. This required an analytic period that covered the years 2011 through 2049, the last year of the economic life of a PV system installed in 2025. A corollary scoping assumption was the renewable energy contract length. For this study we assumed a 25-year contract length, based on a variety of reasons as described in Chapter 5.[6] A shorter contract length of 5- to 10- years would be expected to increase rate impact and would lead to higher annual rate impacts in the early years of the study period.

1.3. Policy Objectives and Evaluation Criteria

The Act requires the Solar Study analyze and evaluate the costs and benefits of implementing a policy with named installation targets, and to identify and compare policy mechanisms that could achieve the target goals. In order to complete these tasks, it was necessary to identify the policy objectives associated with achieving these installation goals.

Identification of policy objectives served two purposes in this study:

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6 Based on the finding that for performance based incentives longer-term contracts will serve to minimize ratepayer impacts, that current small-scale lease agreements for PV systems often have a contract length as long as 20-years, and the report that a recent large-scale PV project was awarded in Connecticut for a 20-year contract length, it was concluded that a contract length on the order of 20-years could be assumed in this study. Given that a modeled 20-year contract length is not expected to produce significantly different results from a 25-year contract length, and that alignment of contract length assumptions with economic life of a PV assumptions leads to significant reductions in modeling complexity, it was assumed that the contract length would be 25-years.

First, they were used in the selection of policy mechanisms, and provided a means to interpret the strengths and limitations of those mechanisms at achieving desired outcomes.

Second, identification of policy objectives helped to establish criteria against which the various policy mechanisms would be evaluated in meeting the targets in the Act. These criteria were needed in order to compare the scenarios and sensitivities studied, as well as measure the effectiveness of a policy at achieving applicable policy objectives.

A broad set of potential objectives was identified through research[7], based on both examination of New York renewable energy policies and other industry experience with solar policies. Using the policy objectives identified below, corresponding quantitative and qualitative metrics were developed (a summary is presented in Chapter 11) to assess progress towards meeting the objectives.

One important observation is that some policy objectives conflict-- maximizing one may take away from maximizing another (Grace, Donovan, & Melnick, 2011). As such, different policy approaches may yield different tradeoffs among these objectives. For example, some may be more effective at minimizing ratepayer cost, others at delivering economic development benefits.

The objectives and criteria used for analysis in this Solar Study are summarized in Table 3 below.

Finally, in addition to objectives, policies are subject to constraints. Constraints that impact PV policy choices include avoiding Federal preemption via the supremacy clause of the US constitution[8] and avoiding undue discrimination under commerce clause of the US constitution.[9] Constraints on the ability of the market to respond to the policy include siting feasibility; and grid interconnection constraints.

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7 The proposed policy objectives was based on a literature survey of potential policy objectives and constraints from a range of sources, including (i) the Act; (ii) previously introduced New York solar legislation, such as the NY Renewable Energy Sources Act, A00187A (2009); NY Solar Industry Development and Jobs Act, A11004 (2010); and NY Solar Jobs Act, A05713 (2011); (iii) existing NY renewable energy programs, particularly the RPS (see Section 2.2); (iv) solar policy goals from other states as summarized in *When Renewable Energy Policy Objectives Conflict: A Guide for Policy-Makers* (Grace, Donovan, & Melnick, 2011); (v) published studies by the National Renewable Energy Laboratory (NREL, 2011a), Deutsche Bank (DB Climate Change Advisors, 2009) and the California Energy Commission (KEMA, 2010).

8 Federal law may limit some approaches to standard offer PBIs, relating to PURPA and the Federal Power Act (Hempling, Elefant, Cory, & Porter, 2010).

9 The commerce clause may impact the ability of a policy to limit eligibility to in-state generation (Elefant & Holt, 2011).

Table 3. Potential Driving Policy Objectives for PV

Category	Policy Objectives
Environmental	• Minimize greenhouse gas emissions • Minimize criteria pollutant, mercury and other air pollution emissions • Reduce impacts related to water use in thermal electric generation (thermal, quality, quantity) • Preservation of land from fuel cycle impacts (mining, drilling, etc.) • Minimize use of land with higher value alternative uses • Reduce reliance on finite fossil fuels
Energy Security and Independence	• Increase fuel diversity • Increase energy security and supply reliability • Increase domestic energy production
Reliability	• Reduce electric delivery disruption risk • Minimize negative grid planning and operating reserve impacts • Minimize distribution system negative reliability impacts (avoiding degradation of system loss of load probability)
Economic Development	• Maximize net in-state job creation • Maximize gross state product (GSP) growth • Support existing clean technology industries • Minimize out-of-state capital flows • Create stable business planning environment (for supply chain investment)
Energy Cost	• Reduce distribution system upgrades, and minimize additional upgrades caused by PV • Reduce wholesale prices (energy and capacity impacts) • Minimize direct cost of policy to ratepayers • Minimize total cost of policy (exclusive of monetizing environmental, public health or other impacts) • Integrate well with the competitive retail market structure in NY • Integrate well with the competitive wholesale market structure in NY
Technology Policy	• Create a self-sustaining solar market • Assist emerging technologies in becoming commercial technologies • Foster technology innovation & development
Societal	• Ensure geographic distributional equity/ effectiveness at aligning benefits with those who bear the costs • Maximize benefits to environmental justice communities

2. BACKGROUND

2.1. Introduction

The global PV industry continues to grow at a rapid pace and both market and policy conditions remain highly dynamic. This chapter provides background on the state of the PV policy and market environment in New York, the region, and the rest of the world.

Key findings:

- The global PV market has grown substantially over the past decade. Global PV demand in 2010 reached 17,000 MW, with Germany accounting more than 7,000 MW.
- The existing global supply chain would adequately meet the needs of New York's market as it grows towards the 5,000 MW target.
- New York has aggressive renewable energy goals and robust policies that support those goals.
- Current New York policies support a range of renewable technologies including several high-cost early-stage generation sources, like PV, that have the potential to reach significant market penetration as costs decline .
- Supported by stable policies and a growing workforce, the New York PV market has gone from an 8 MW market in 2007 to a 60 MW market in 2011.
- Existing PV programs have stimulated a stable and growing market, but this market is small in relation to other East Coast markets.

This chapter is organized as follows:

- Section 2.2 discusses New York's electric market and regulatory context.
- Section 2.3 provides an overview of the New York Renewable Portfolio Standard policy, including its structure and its results to date.
- Section 2.4 explores baseline conditions in the New York State PV market at present, including an overview of installed capacity to date, an overview of the in-state solar industry, and a catalog of currently available federal, state and local policies.
- Section 2.5 situates New York State in the context of the global PV market. It provides background on the total installed capacity in the US and worldwide, and reviews trends to date in the international markets for key PV system inputs, including silicon, cells and modules, and inverters.
- Section 2.6 summarizes PV component and system costs trends in New York, and New York's experience relative to national trends.

Appendix 1 provides more detailed information summarizing trends in PV technology and performance.

2.2. New York Electric Market and Regulatory Context

Beginning in the mid 1990s, New York State has implemented competitive wholesale markets for electricity (both capacity and energy) through Public Service Commission (PSC) Orders and other regulatory processes. Institution of competitive markets has included several activities, including divestiture of utility-owned generation, the establishment of commodity pricing platforms for wholesale electricity at a newly-(re)organized New York Independent System Operator, and the permission for competition for retail energy services. In New York, independent power providers (that is, non-utilities) are the primary owners of electric generation plant, and energy prices are set competitively by market forces, either through contracts negotiated between the independent generation owners and load-serving entities (including utility companies) or through several wholesale energy auction platforms administered by the NYISO. New York's current energy and environmental policies, such as the Renewable Portfolio Standard (described in this chapter), are designed in sync with this market structure, and have functioned well by allowing for competitive programs to limit ratepayer exposure to policy costs, while also minimizing interference with the broader competitive electricity markets.

Chapter 3 of this study examines the experiences of several countries and states, which use a variety of policy mechanisms to incentivize widespread adoption of PV installations. While the use of a variety of policy mechanisms demonstrates that each of these mechanisms can effectively function in other jurisdictions, the policy objectives and regulatory/market frameworks should also be a factor in determining which policy mechanism may be best designed accounting for local market and regulatory considerations. Any policy and/or policy mechanism that is under consideration to achieve stated PV policy objectives must be examined for its fit within the context of New York's electric market and regulatory framework.

2.3. New York Renewable Portfolio Standard: Policy Context and Objectives

Between 1996 and 1998, PSC implemented, through regulation, a competitive retail choice marketplace within the service areas of New York's investor-owned utilities. In 2004, the Commission established the state's renewable portfolio standard (RPS) with the objective of preserving and increasing the contribution of renewable energy serving state retail electric load at the lowest cost to ratepayers. In a September 24, 2004 Order, the Commission designated NYSERDA as the central procurement administrator for the RPS Program. In doing so, the Commission noted an expectation that retail customers ("Voluntary Market") would contribute at least 1% toward the 25% goal, thus leaving baseline renewable resources, State Agencies' purchases under Executive Order 111 (EO 111), voluntary purchases by the Long-Island Power Authority and NYSERDA procurements to realize the remaining incremental requirement (N.Y. PSC, 2004). This goal was later increased to 30% by 2015 (N.Y. PSC, 2010b). The Commission established explicit objectives for the RPS design that considered costs, benefits, reliability, and other factors. The seven categories of objectives identified, listed in priority order, are:

1. **Renewable Resources:** institute an RPS to increase New York State's supply of renewable resources with the ultimate aim of establishing a viable, self-sustaining competitive renewable generation market;
2. **Generation Diversity for Security and Independence:** diversify the generation resource mix of energy retailed in New York State to improve energy security and independence, while ensuring protection of system reliability;
3. **Creating Economic Benefits:** develop renewable resources and advance renewable resource technologies in, and attract renewable resource generators, manufacturers, and installers to New York State;[10]
4. **New York's Environment:** improve New York's environment by reducing air emissions, including greenhouse gas emissions, and other adverse environmental impacts on New York State, including upon underserved communities, of electricity generation;
5. **Equity and Economic Efficiency:** develop an economically efficient RPS requirement that minimizes adverse impact on energy costs, allocates costs equitably among ratepayers, and affords opportunities for recovery of utility investment;
6. **Administrative Fairness and Efficiency:** develop an RPS that is administratively transparent, efficient, and verifiable; and
7. **Competitive Neutrality:** develop an RPS compatible with competition in energy markets in New York State **(N.Y. PSC, 2004)**.

In addition, one of the explicit objectives of the program is to ensure program benefits accrue to New York ratepayers funding the program (N.Y. PSC, 2004).

2.3.1 RPS Approach and RPS Targets

In most states, the compliance obligation for RPS programs is placed on load-serving entities (LSEs), the utilities and competitive energy service providers supplying retail electric customers. LSEs are required to supply their customers with an increasing percentage of their supply portfolios from eligible renewable energy resources. In contrast, New York's RPS program uses a 'central procurement' model, administered

10 NY P.S.C. (2004) at 10, pointed out that implementation of "the RPS is also expected to create greater regional benefits in New York State through economic development. Manufacturing of renewable energy equipment, procurement of fuels such as biomass, and construction and operation of generating facilities will create direct and indirect jobs, purchases of local products, which add revenues to local economies, and additional tax payments."

by NYSERDA.[11] The Commission ordered the state's investor-owned utilities to collect an authorized quantity of funds each year from their ratepayers in order to fund NYSERDA's RPS implementation responsibilities. NYSERDA does not procure renewable energy directly. Rather, NYSERDA provides incentives through two RPS 'tiers' established by the Commission: the Main Tier and the Customer-Sited Tier.[12]

The Main Tier is designed to provide production incentives to medium-to-large scale renewable electric generation facilities that deliver their electrical output into the wholesale power market administered by the New York State Independent Service Operators (NYISO).[13] The Main Tier central procurement uses a competitive solicitation process to offer long-term (up to 10 year) contracts for *RPS Attributes* to eligible generators who deliver the associated energy to New York end-users.[14] By acquiring the RPS Attributes, rather than the associated electricity, the RPS program ensures that increasing amounts of renewable electricity will be supplied to the State's power system, while minimizing interference with the State's competitive wholesale power markets.

The Customer-Sited Tier is designed to accelerate the development of emerging technologies, because of their environmental benefits and ability of some of the technologies to be sited in urban, heavy-loaded areas. The Customer-Sited Tier supports smaller renewable energy installations located behind the retail meter, including PV systems, fuel cells, anaerobic digesters, solar thermal systems and customer-sited wind.[15] Eligible Customer-sited Tier resources are supported through a combination of financial and other incentives for the "buy-down" of capital costs and/or energy production. The 2015 target for the NYSERDA's central procurement RPS programs is 10.4 million MWh per year, roughly the size of the combined 2015 RPS new renewables targets of Massachusetts, Connecticut, Rhode Island and New

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11 New York is the only state to implement an RPS central procurement model, with no specific requirements on LSEs. Illinois uses the Illinois Power Agency to arrange procurements for their LSEs, but sets individual LSE targets for the acquisition of renewable energy for their customers.

12 In addition to these two tiers, the Commission established a Maintenance Resource program to ensure continued operation of existing renewable generating power plants or "baseline resources" (19.3% of the energy sold at retail in New York was being generated by renewable resources that existed prior to adoption of the RPS in 2004. Plants that can demonstrate financial hardship through a formal request to the Commission can sell their RPS Attributes to NYSERDA as well.

13 While PV systems are eligible to bid into the Main Tier program, this is not the primary mechanism whereby PV is incentivized in New York.

14 Under the Main Tier RPS, NYSERDA procures *RPS Attributes*. One RPS Attribute is created by the production and delivery into New York's wholesale electricity market of one MWh of electricity by an eligible RPS resource. RPS Attributes include any and all reductions in harmful pollutants and emissions, such as carbon dioxide and oxides of sulfur and nitrogen. RPS Attributes are analogous to renewable energy credits (RECs) used for compliance with most other RPS policies. New York has yet to establish a REC trading system or authorize the use of RECs for RPS compliance. If such a system is established, NYSERDA would procure RECs.

15 As a result of Commission decisions issued in November and December of 2010, customer-sited generation can now choose to compete for long-term contracts via the Main Tier program component.

Hampshire (VT PSB, 2011). This total consists of approximately 9.8 million MWh per year from the Main Tier procurements, with an additional 0.6 million MWh per year from Customer-Sited Tier programs.[16]

2.3.2 RPS Main Tier

To meet the Main Tier targets, NYSERDA has implemented a competitive procurement process in order to achieve program goals cost-effectively. Eligible generators may be located either within New York or outside New York, but those outside of New York must deliver their energy into the state. The Commission saw this as an effective structure to make renewable energy generation projects financeable in the state's competitive retail market. Long-term contracts for renewable energy credits contribute to the cost-effectiveness of the program by supporting developers' ability to get projects financed, thereby reducing generators' development costs (NYSERDA, 2009).[17]

2.3.2.1. Economic Benefits

The Commission issued an Order in 2006 requiring that NYSERDA incorporate economic benefits into scoring bids under subsequent solicitations. The Commission authorized the use of bid evaluation criteria used by NYSERDA today, under which NYSERDA selects projects based on a 70/30 weighting of least cost and demonstrable economic benefits to the state, respectively. In late 2010, the Commission reaffirmed the weighting of economic benefits at 30% in the competitive selection process, while relaxing former incremental economic benefits requirements to allow all claims of in state spending after January 1, 2003. The economic benefits achieved by adding a weighting to the evaluation of bids are associated with the activities necessary to plan, develop, construct and operate new or upgraded renewable energy projects. These activities increase both long-term and short-term employment and demand for goods and services. New renewable energy projects also create economic benefits because they pay property taxes or make payments in lieu of taxes (PILOT), as well as providing lease or royalty payments to landowners. Biomass plants also provide an added local economic benefit because typically they utilize locally-sourced fuel (NYSERDA, 2010a).

2.3.2.2. Results

Through December 31, 2011, NYSERDA has completed seven Main Tier solicitations.[18] The first was completed in early 2005 and the most recent was completed in December 2011. From the seven solicitations, NYSERDA has contracted with 63 large-scale electricity generators. Contracts with three

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16 10.4 million MWh is roughly 6 percent of expected load in 2015.

17 The Commission has authorized NYSERDA to consider other means to procure Main Tier RPS Attributes, including through a descending clock auction or alternatively, through a standard offer. However, these approaches have yet to be pursued or authorized.

18 The Commission has authorized NYSERDA to conduct future Main Tier competitive solicitations at least annually, in consultation with DPS staff, and NYSERDA has posted a tentative schedule consisting of two solicitations per year through 2013.

generators for the delivery of RPS Attributes ended prior to the end of 2011. Of the 60 remaining facilities, one is located in Quebec, two are located in Pennsylvania, and the rest are in New York. When all reach commercial operation, these 60 facilities will add approximately 1,862 MW of new renewable capacity, with 1,815 MW located in New York. Wind power is the predominant generating technology representing 1,675 MW of new renewable capacity of which 1,326 MW is in operation today- roughly 28 times the amount that was operating before the RPS was instituted. The balance of new capacity is comprised of hydroelectric upgrades, landfill gas to electricity, and biomass (direct and co-fired) facilities. As of December 31, 2011, 49 facilities representing approximately 1,456 MW are operating with the remaining 11 expected to be in operation by September 30, 2013. Further details on the status of Main Tier projects can be found below in Table 4.

Table 4. Project Development Status for Active Main Tier Contracts through 2011[19]

MAIN TIER	MW Operating	MW In Development, Construction	Total MW	# Operating	# In Development, Construction	Total #
Wind	1,326.0	349.0	1,675.0	16	5	21
Hydro	42.4	8.9	51.3	22	3	25
Biomass	31.0	43.3	74.3	2	1	3
Landfill gas	57.0	4.8	61.7	9	2	11
Total	**1,456.4**	**406.0**	**1,862.4**	**49**	**11**	**60**

Based on the success of the Main Tier, New York has more in-state renewable energy capacity additions attributable to its state RPS policy than any other state in the Northeast[20] (Clean Energy States Alliance, 2008). Furthermore, New York's Main Tier has been recognized as one of the most cost effective RPS mechanisms in the U.S. to attract investments in large scale generating facilities. According to a 2009 Program Evaluation Report, prices paid for RPS Attributes are "…reasonable and lower than those in most other states with an RPS program." (NYSERDA, 2010a). The weighted average RPS Attribute price ($/MWh) for each of the seven Main Tier solicitations has ranged from a low of $14.75/MWh in November of 2007 to a high of $28.70/MWh in December of 2011.

19 NYSERDA Jan 17, 2012.

20 See Appendix 14 for a graph showing the 2010 cumulative (non-hydro) renewable installed capacity by state in the Northeast.

See Figure 1 below for the results of each solicitation.

Figure 1. Weighted Average RPS Attribute Price - by Main Tier Solicitation

A 2009 study by independent program evaluation contractors found that the RPS, if fully implemented at the 30% by 2015 level, would contribute significantly to New York's economy. The study found that the direct benefits, those from direct employment and spending, would be approximately $6 billion and when the effects on the broader economy are considered, the total benefits could exceed $12.5 billion (KEMA, 2009).

2.3.3 Customer Sited Tier

The Customer Sited Tier (CST) was designed to encourage customers to install their own behind-the-meter energy production systems. It was created with the New York RPS in 2004 and initially included programs for PV, small wind, anaerobic digesters and fuel cells. At the conclusion of the Commission's mid-course review of the RPS, it issued an Order in April 2010 which (N.Y. PSC, 2010a):

- Established new goals for the CST program for the existing technologies (PV, on-site wind, anaerobic digesters and fuel cells)
- Authorized a new program whose goal is to encourage additional CST installations in the downstate region (NYISO zones G, H, I, J)
- Authorized a new program for solar thermal
- Authorized funding of CST through 2015; and
- Directed creation of the new CST operating plan.

The 2010 Customer-Sited Tier Operating Plan was adopted on June 29, 2010 (NYSERDA, 2010c). This plan was developed by NYSERDA with input from the Department of Public Service. The plan contains program goals, funding levels and program logistics.

2.3.3.1. Program Goals

The 2010 Operating Plan lays out the program goals by technology through 2015 and what was achieved through the end of 2009. Almost 30 MW was installed, pending or planned as of December 31, 2009 under the first phase of the RPS program, including 20 MW of PV. The goal is to install an additional 254 MW for a cumulative installed capacity of 284 MW, including approximately 170 MW of PV by 2015.

2.3.3.2. Approach

The majority of the technology-specific programs offer open enrollment, first-come, first-served solicitations. The design of each solicitation is tailored to the target technologies and markets. The programs offer a combination of up-front capacity-based incentives and performance-based incentives. The CST also includes a regional competitive bidding program for PV and anaerobic digesters focused in NYISO Zones G, H, I and J. Unlike the other CST programs, the regional program uses a reverse auction model whereby the lowest bids (i.e., request for incentive per kWh to be generated) are selected. The regional program provides 30% of the incentive level up-front and the remaining 70% over the first 3 years of performance.

2.3.3.3. Progress to Date

The New York State Renewable Portfolio Standard Performance Report summarizes progress related to the CST goals in 2010 (NYSERDA, 2010a). The regional and solar thermal programs commenced in 2011, so no progress was reported on those programs in the latest RPS Annual Report (through the end of 2010). Preliminary results in 2011 for the regional program show robust demand in the downstate area and suggest that a competitive bidding model can reduce incentive prices relative to standard offer programs (NYSERDA, 2012). Table 5 and Table 6 below show the progress in both capacity and energy, respectively, through the end of 2011.

Table 5. Actual and Expected Capacity as of December 31, 2011

	ACTUAL INSTALLED CAPACITY (MW)	CAPACITY UNDER CONTRACT BUT NOT YET INSTALLED (MW)	APPLICATIONS ACCEPTED WITH CONTRACTS PENDING	TOTAL PENDING AND INSTALLED CAPACITY (MW)
PV	32.06	16.97	2.75	51.78
Geographic Balancing	0.00	7.95	18.67	26.62
Fuel Cells	0.37	0.44	2.02	2.83
Anaerobic Digester Biogas	3.52	3.32	10.16	17.00
On-Site Wind	0.82	0.60	1.37	2.79
Solar Thermal	0.21	0.1	3.06	3.37
Program Total	36.98	29.38	38.03	104.39

Table 6. Actual and Expected Energy Production as of December 31, 2011

	ACTUAL ENERGY PRODUCTION FROM INSTALLED CAPACITY (GWh)	EXPECTED PRODUCTION FROM CAPACITY UNDER CONTRACT BUT NOT YET INSTALLED (GWh)	EXPECTED PRODUCTION FROM APPLICATIONS ACCEPTED WITH CONTRACTS PENDING (GWH)	TOTAL EXPECTED PRODUCTION (GWh)
PV	37.64	19.92	3.23	60.79
Geographic Balancing	0.00	10.44	24.53	34.97
Fuel Cells	1.70	3.33	16.12	21.15
Anaerobic Digester Biogas	24.29	23.27	71.84	119.40
On-Site Wind	0.92	1.19	3.03	5.14
Solar Thermal	0.24	0.12	3.48	3.84
Program Total	64.79	58.27	122.23	245.29

2.3.4 Overall RPS Program Results

The progress to date in the Main Tier and Customer Tier represents 44.8% of the combined Main Tier and Customer Tier targets. The specific results are summarized in Table 7 below.

Table 7. NYSERDA 2015 RPS Energy Targets (in MWh) and Planned Progress as of December 31, 2011 (NYSERDA, 2012)

	TARGET	PROGRESS[21]	PROGRESS AS % OF TARGET
Customer Sited Tier	623,390	245,290	39.3%
Main Tier	9,774,464	4,408,239	45.1%
Total	10,397,854	4,653,529	44.8%

Over the course of 2011, the RPS CST PV upfront incentive program cost on average $55.9/MWh.[22] This is nearly twice the cost of the weighted average attribute price of the RPS Main-Tier's most recent procurement of $28.7/MWh in December, 2011. If the energy production from the projects supported under the Main Tier is taken into account, as was done for the PV incentive estimate, the PV incentive would be five times greater than the Main Tier incentive level.[23]

2.4. The New York PV Market and Baseline Solar Policies

For more than a decade, New York has had an active and dynamic solar market supported by federal, state and local policies. Compared with neighboring states, New York has a relatively small but stable and growing PV market. Total system installations in 2011 were 58.8 MW, more than double the installed capacity from 2010.[24] Figure 2 shows annual PV capacity additions in the New York market based on LIPA, NYPA and NYSERDA program data.

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21 Progress for the Customer-Sited Tier represents generation in 2015 from capacity installed, capacity under contract with NYSERDA, and capacity associated with accepted applications having pending contracts. Progress in the Main Tier represents contracted quantities, adjusted down to account for pending contract adjustments.

22 Based on 2011 program data and assuming a 13.4% capacity factor and 25-year life of the systems.

23 If the remaining 10 to 15 years of energy production were included, the effective Main Tier incentive level would be approximately $11/MWh.

24 Data from NYPA, LIPA and NYSERDA databases.

Figure 2. Annual PV Capacity Additions in New York 2002-2011[25]

In 2011, neighboring New Jersey installed 240 MW while Pennsylvania and Massachusetts installed 91 MW and 38 MW, respectively (Photon, 2012). These other northeast state solar markets are currently supported primarily through dedicated solar tiers in their renewable portfolio standards.

The following section characterizes the current state market and also describes the government policies that have helped to shape the New York PV industry. Where data is available, the New York market is compared to other surrounding states.

2.4.1 System Size and Metering Configurations

The New York State programs originally supported small commercial and residential PV systems funded through incentive programs, federal incentives and a state residential tax credit. Prior to the development of the NYSERDA regional program launched in 2011 (PON 2156) and recently launched initiatives by LIPA and NYPA, incentives were not available for systems larger than 50kW. These incentive caps created an upper bound for system sizes in New York, and consequently a robust large commercial and utility scale PV market has not developed in the state. Incentive programs in New Jersey, Pennsylvania and Massachusetts are either without size caps or have caps significantly higher than in New York. This has led to more diversity in system sizes in these markets. Figure 3 shows the relative mix of PV system sizes by total installed capacity in New York and in neighboring states for 2010.

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25 The LIPA – Wholesale Scale bar consists of a single 32 MW installation at Brookhaven National Labs. The LIPA solar wholesale solar power purchase program is expected to install 17 MW in 2012. No future installations under this program are currently planned.

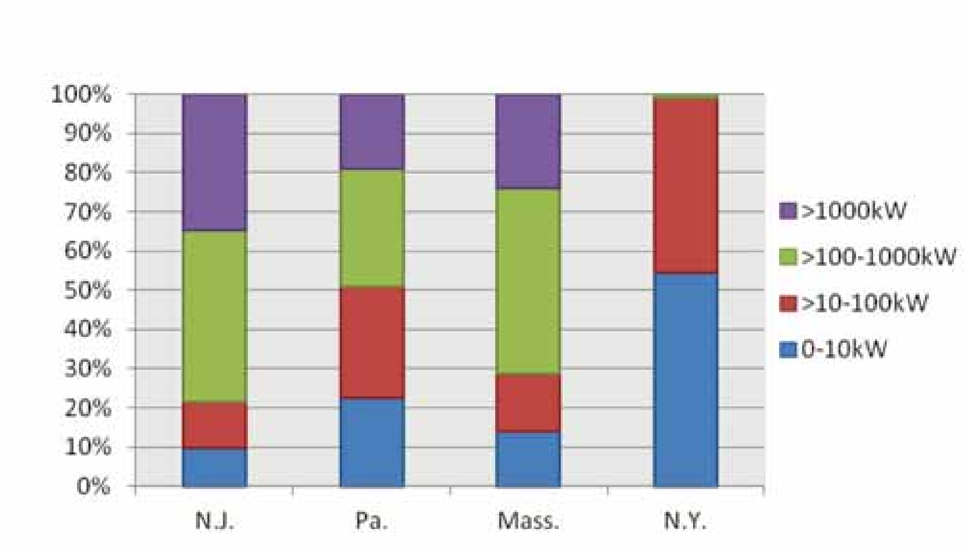

Figure 3. Relative Mix of PV System Sizes by Total Market Capacity in New York and Neighboring States in 2010.

While the New York market was dominated by residential and small commercial PV systems through 2010, implementation of new programs by NYSERDA and LIPA are changing this market mix in the near term. LIPA has recently procured several MW-scale PV systems through its 50-MW utility-scale program which are expected to become operational by 2013. This procurement included a 32-MW utility-scale system at the Brookhaven National Lab which was interconnected in November 2011 and is the largest PV system on the east coast (Snyder, 2011) (LIPA, 2011c). Additionally, the NYSERDA regional program has issued two procurements and has awarded a total of 26.6-MW of PV, including over 20-MW of contracts for large-commercial and MW-scale PV systems in the Hudson and New York City (NYC) load zones (NYSERDA, 2011b). On behalf of New York, NYSERDA and LIPA also received $14.9M in American Recovery and Reinvestment Act funding that will bring on line approximately 8.2MW of PV by 2012, including 2.1MW of commercial scale PV.

Current NYSERDA incentive programs (PONs 2156 and 2112) only provide incentives for PV systems that are interconnected behind the customer's meter (NYSERDA, 2011b) (LIPA, 2011a). The LIPA small business and residential solar programs also require systems to be installed only at net-metering eligible sites (LIPA, 2011b). Due to these restrictions, and the size caps placed on incentive programs, the New York solar market has to-date consisted of behind-the-meter installations. Installations that are part of the LIPA 50MW utility-scale program will be installed in front of the meter (LIPA, 2008).

2.4.2 PV Market Geographic Distribution

PV market activity in New York is not evenly distributed across the state with some load zones, in particular Long Island, having a disproportionately large share of installations. Table 8 shows the installed capacity in each load zone by year based on the LIPA and NYSERDA upfront incentive program database.

Table 8. Installed PV Capacity in kW by Year and Load Zone from NYSERDA and LIPA Databases

Year	Capital	Hudson Valley	New York City	Upstate	LIPA	Annual Total
2000	n/a	n/a	n/a	n/a	2	**24**
2001	n/a	n/a	n/a	n/a	33	**33**
2002	n/a	n/a	n/a	n/a	829	**829**
2003	36	89	11	89	762	**987**
2004	72	185	37	157	761	**1,211**
2005	116	245	57	183	827	**1,428**
2006	237	514	197	288	1,597	**2,834**
2007	484	949	190	511	1,729	**3,863**
2008	680	1,433	242	660	3,056	**6,070**
2009	1,449	2,532	921	1,749	5,367	**12,018**
2010	2,436	3,281	1,401	4,584	10,902	**22,604**
2011	3,463	2,793	3,331	4,512	44,658	**58,757**
Total	**8,973**	**12,021**	**6,387**	**12,734**	**69,658**	**109,773**

Systems installed in the LIPA territory make up nearly half of all PV capacity installed in the state. This can be attributed to significantly higher per capita aggregate funding levels under the LIPA program. As of the end of 2010, LIPA had provided nearly $95 million in funding for completed PV projects over the course if its programs.[26] Customers in the LIPA territory represent about 6.5% of the state's total electric load.[27]

Within the territories covered under the NYSERDA programs, a disproportionately small number of systems have been built in the New York City zone, given this zone's high load, population and number ofutility customers. Several published reports have discussed the challenges inherent in developing PV systems in New York City (Veilleux, Rickerson, Case, & Kling, 2010; Ginsburg, 2010). These include technical and regulatory challenges interconnecting to Con Edison's secondary network grid and issues around successfully navigating the New York City permitting process. As a result of these challenges, installations in New York City have taken significantly longer to complete than PV installation in other

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26 Funding data provided by LIPA staff

27 Data provided from RGGI 2011 modeling data

parts of the state. New York City is currently working to address these challenges with its partners at Con Edison, through the U.S. DOE funded Solar America Cities initiative.

Typical NYSERDA review and approval time for an incentive application is four to six weeks. Table 9 shows the average time a PV system takes to progress from having an approved NYSERDA incentive application to final payment being issued to the installer, for each of the NYSERDA program load zones, and reflects procurement, permitting, scheduling, construction, interconnect and inspections. Overall timeframes and differences between the load zones reflect the technical and regulatory challenges, but have been dramatically reduced over time.

Table 9. NYSERDA Upfront Incentive Program Average Days to Complete a PV Project after Approval of Incentive Application (July 1, 2010 – December 31, 2011)

LOAD ZONE	AVERAGE NO. OF DAYS
CAPITAL	89
HUDSON VALLEY	92
NEW YORK CITY	118
UPSTATE	85

2.4.3 The New York PV Value Chain

The solar market value chain[28] consists of a variety of business types, from polysilicon, wafer, cell and module manufacturers, to installers, project developers and financiers. This section will discuss the existing New York solar market value chain with a particular focus on in-state market resources.

The solar industry has been rapidly growing both globally and in the United States. The New York State Department of Labor recently conducted a study on New York's green labor market, which showed that there were 1,400 PV installers in New York. The study also identified significant "green" component manufacturing and professional services in New York, but due to the nature of the data collected, did not directly attribute these workers to specific industries, rather to common occupations in these areas (N.Y. Dept. of Labor, 2011). Another recent study by The Brookings Institution estimated that the United States had more than 24,000 jobs in the national PV value chain (Muro, Rothwell, & Saha, 2010). The same analysis developed a jobs estimate for the New York PV workforce and estimated 556 solar jobs in 2010, a 14.5% annual sector growth over the 2003-2010 period (Brookings-Battelle, 2010). Though this indicates strong growth in New York, the estimated number of PV jobs is still significantly lower than the jobs found in the Department of Labor study's PV installation occupation alone, and indicates the uncertainty in

[28] In this context, the value chain refers to all inputs for a PV system, such as raw materials, components and installation labor. Values such as generated energy, environmental benefits and other are considered in other parts of this study.

reporting and accounting for current PV jobs. Table 10 compares the Brookings Institution study's solar employment number in New York to other leading states. A similar study was recently released by The Solar Foundation and Cornell University. This analysis estimated jobs for both the PV and solar thermal industries in New York and found more than 4,000 total solar jobs in New York (The Solar Foundation, 2011).

Table 10. Estimated 2011 PV Industry Employment in Five Leading States, New York and New Jersey (Brookings-Battelle, 2010)

RANK	STATE	ESTIMATED PV JOBS	PERCENT OF U.S. TOTAL
1	California	6,492	27%
2	Michigan	2,370	10%
3	Colorado	1,497	6%
4	Massachusetts	1,390	6%
5	Ohio	1,348	6%
11	New Jersey	670	3%
15	**New York**	**556**	**2%**

2.4.3.1. New York State PV Manufacturers

A survey of North American solar component manufacturers found eight firms currently active in New York (Matz, 2011). These include three module manufacturers, three inverter manufacturers, an equipment manufacturer and a polysilicon supplier. Table 11 lists solar component manufacturers currently reporting capacity in New York.

Table 11. PV Component Production Capacity in New York State

MANUFACTURER	COMPONENT	SITE
Globe Specialty Metals Inc.	Silicon	Niagara Falls
Atlantis Energy Systems, Inc.	Modules	Poughkeepsie
Solartech Renewables, LLC	Modules	Ulster
Prism Solar Technologies, Inc.	Modules	Highland
Inverters Unlimited, Inc.	Inverters	Albany
Direct Grid Technologies LLC	Inverters	Edgewood
Sepsa Electronica de Potencia SL	Inverters	Ballston Spa

Several of these firms are local start-ups that have grown out of industry cluster development efforts (e.g. Solartech Renewables).[29] While others are international manufacturers that have chosen to locate in New York (e.g. Sepsa).

2.4.3.2. New York State PV Installers

The solar installation market consists of a diverse group of local, regional and national industry players. In 2011, NYSERDA saw a large growth in the number of eligible participating installers and affiliated firms. Some installers have affiliated with firms offering Power Purchase Agreements (PPAs) in addition to direct sales. PPAs provide third party ownership and long term maintenance. According to program data, as of December 2011, more than 370 individuals are eligible to serve as primary installers on NYSERDA-supported PV projects. Table 12 lists the top five firms, by MW, who have participated in the NYSERDA upfront incentive program over the past few years. Additionally, Long Island Solar Industries Association lists more than 25 installation companies in its membership database.

Table 12. Top Five Firms Installing PV through NYSERDA Program

INSTALLATION FIRM	NYSERDA MW 2009-MID-2011	CORPORATE HEADQUARTERS	PERCENT OF CAPACITY
Solar Liberty Energy Systems, Inc.	4.5	Buffalo, N.Y.	12.5
Hudson Valley Clean Energy	4.5	Rhinebeck, N.Y.	12.5
Mercury Solar	3.9	Port Chester, N.Y.	10.9
Alteris Renewables, Inc/Real Good Solar	1.9	Wilton, Conn.	5.3
New York Light Energy	1.8	Latham, N.Y.	5.2

2.4.4 Current Incentives

A diverse array of incentives are available to PV system owners in New York. These range from federal tax credits and depreciation, to local property tax exemptions and abatements. The following section discusses each of the existing incentives available to residents and businesses who install PV systems in New York.

2.4.4.1. Federal Business Incentives

The federal government has legislated a diverse array of incentive programs for renewable energy and PV. Several of these incentives are not consistently available to project developers. Incentives such as the Rural Energy for America Program (REAP) loan guarantee program and the Renewable Energy Production

[29] Solartech Renewables has located in the TechCity green technology cluster development site at the former IBM facility in Kingston. Additionally, Linou, a Chinese solar cell manufacturer recently agreed to develop a manufacturing facility in Fishkill that will supply solar cells to Solartech Renewables.

Incentive (REPI) may be available from time to time when Congress appropriates funds, however these programs are not significant drivers of solar markets in the U.S. With that, this section will focus on broadly applicable federal policies that are available to a significant portion of potential PV projects in New York.

Business Investment Tax Credit (ITC)

Commercial, industrial, utility, and agricultural taxpayers are eligible for the Investment Tax Credit (ITC), a 30% credit that is available for eligible systems installed by December 31, 2016. Systems installed after that date are eligible for a 10% tax credit. The PV property must begin operation in the year in which the tax credit is first taken. Prior to January 1, 2012, eligible taxpayers could opt to receive a cash grant from the Department of Treasury in lieu of the ITC (see *Section 1603 Treasury Grant* summary below) (U.S. Code, 2009).

Section 1603 Treasury Grant

Prior to January 1, 2012, taxpayers were eligible to receive the federal business ITC as an upfront cash grant from the U.S. Treasury Department instead of receiving the ITC. The grant is equal to 30% of the solar energy property basis. System qualifying for the cash grant must have been placed in service in 2009, 2010, or 2011, or had commenced construction by December 31, 2011 to be eligible for the treasury grant. The beginning of construction is defined as the point at which the applicant has incurred or paid at least 5% of project costs. Government bodies, non-profits, cooperative electric companies, and other non-tax-paying entities are not eligible for the grant (DSIRE, 2011f).

Five-year MACRS Depreciation and Bonus Depreciation

The federal Modified Accelerated Cost-Recovery System (MACRS) allows businesses to recover eligible equipment investments costs through depreciation deductions. PV properties qualify for a five-year depreciation schedule, expediting what would otherwise be a 20-year depreciation period. Systems installed between 2008 and September 8, 2010, and anytime in 2012, are eligible for a 50% first-year bonus depreciation of the adjusted basis, with the remaining 50% of the property depreciated over the normal five-year MACRS depreciation schedule. Systems placed in service between September 9, 2010 and January 1, 2012 qualify for 100% first-year bonus depreciation of the adjusted basis (IRS, 2011). Table 13 shows the five-year MACRS depreciation schedule.

Table 13. Five-year MACRS Depreciation Schedule

RECOVERY YEAR	ANNUAL DEPRECIATION PERCENTAGE
1	20.00
2	32.00
3	19.20
4	11.52
5	11.52
6	5.76

2.4.4.2. Federal Residential Incentives

The federal tax credit for residential energy property is offered for PV, solar water heaters, wind, geothermal heat pumps, and fuel cells using renewable fuels. Eligible taxpayers may take the 30% tax credit, and any excess credit may be carried forward to the following tax year. Unlike the business ITC, individuals eligible for the residential ITC may not opt to receive a grant from the U.S. Treasury Department in lieu of the ITC. The 30% tax credit is available for qualified energy property expenditures to a taxpayer's residence, although the home does not have to be the taxpayer's principal residence. The credit is available through December 31, 2016, and there is no maximum credit for PV, solar water heaters, wind, or geothermal heat pump systems placed in service after 2008.

2.4.4.3. New York State Incentives: NYSERDA

NYSERDA manages the New York RPS program. As discussed in Section 2.2, the New York RPS requires 30% of all power used in New York to come from renewables by 2015. This program includes both a Main-Tier and a Customer-Sited Tier. The Customer-Sited Tier encompasses small-scale generators, such as a PV system on residential and commercial properties and has been a main driver of PV installations in the non-LIPA New York territory. This section discusses the incentives available as part of the Customer-Sited Tier.

Customer Sited Tier Upfront Incentives

As of January 2012, NYSERDA offers a $1.75/watt (DC) incentive for the installation of grid-connected PV systems. The incentive is only applicable to customers of investor-owned utilities in New York State – the customers who pay the state's Renewable Portfolio Standard charge. Customers of the following utilities are eligible for the program: Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, New York State Electric & Gas Corporation, National Grid, Orange and Rockland Utilities, and Rochester Gas and Electric Corporation. The incentive may not exceed 40% of installed costs after tax credits, and the system size may not exceed 110% of demonstrated energy demand (NYSERDA, 2010b).

Table 14. Maximum Incentive Payments and Eligible Capacity for NYSERDA CST Programs.

SECTOR	MAX INCENTIVE	MAX CAPACITY RECEIVING INCENTIVE
Residential	$12,250	7 kW
Non-residential	$87,500	50 kW
Non-profit, municipalities, schools	$43,750	25 kW

Under the NYSERDA PV Incentive program, incentives are only available up to the maximum eligible capacity for each sector, as shown above. Systems that are larger than the eligible capacity are eligible to receive the $1.75/watt incentive up to the relevant cap. Incentives are paid to eligible installers, who must pass the total incentives on to the customers. Incentives are available on a first-come, first-served basis, until the available funds are fully committed or December 31, 2015, whichever comes first (NYSERDA, 2010b). The $1.75/watt incentive is subject to adjustment up or down, depending on demand for the program relative to program budgets.

CST Regional Program

The new CST RPS Regional Program funding provides $30 million annually to downstate regions, in contrast to other CST programs which are available in all IOU territories. This program focuses on the deployment of customer-sited PV and renewable biogas fueled electric generation projects. The funding is for customer-sited, grid-connected systems of at least 50 kW, sited within NYISO Load Zones G, H, I, and J. Incentives will be offered as up-front and performance payments for up to three years; incentives are capped at 50% of total installed costs. Systems located in Strategic Locations (utility-identified regions within NYISO Load Zones G, H, I, and J) will receive a 15% bonus on top of the requested incentive bid.

A competitive selection process for the geographic balancing funding is based primarily on the applicant's proposed incentive level ($/kWh). The regional focus of this incentive is part of a strategy to geographically balance the RPS funding collection and the location of RPS-supported projects. The program is scheduled to run through 2015. The two funding rounds issued during 2011 have closed (NYSERDA, 2011b).

2.4.4.4. New York State Incentives: Long Island Power Authority (LIPA)

Long Island Power Authority (LIPA) is a non-profit municipal electric provider that owns the retail electric Transmission and Distribution System on Long Island. LIPA serves Long Island; covering 1.1 million customers and 6% of the New York state population. LIPA has had programs in place since 2000 to encourage solar deployment. As a publicly-owned utility, LIPA is not required to comply with the state's

Renewable Portfolio Standard, although the LIPA Board of Trustees has enacted a renewable energy target of 30% by 2015 to match the state's goal (Photon, 2011b).

The Solar Pioneer rebate program, LIPA's first PV incentive, was launched in 2000 and is still active today. A similar rebate program, Solar Entrepreneur, is available for non-residential projects (commercial and industrial sector). Under the LIPA PV rebate program, rebates may not exceed 50% of installed system costs or $17,500 (10 kW DC) for residential and $87,500 kW for commercial, whichever is less. Schools, nonprofits, and municipalities are also eligible for the solar rebate program, and qualify for a higher rebate per watt ($2.75/W DC) and maximum incentive ($137,500 or 65% of installed cost, whichever is less). Installations must be grid-connected and comply with all federal, state, and local codes, in addition to New York's Standard Interconnection Requirements. A system must be located in LIPA service territory to be eligible for the rebate program (LIPA, 2011d).

Table 15. Current PV Rebate Program Incentives Levels in the LIPA territory.

SECTOR	REBATE	MAXIMUM CAPACITY ELIGIBLE FOR REBATE
Residential	$1.75/watt (DC) for the first 10 kW	27.5 kW (rebates limited to first 10 kW)
Non-residential	$1.75/watt (DC) for the first 50 kW	2 MW (rebates limited to first 50 kW)
Non-profit, municipalities, schools	$2.75/watt (DC) for the first 50 kW	2 MW (rebates limited to first 50 kW)

The Solar Pioneer and Solar Entrepreneur rebates are set to reflect current PV system costs. There is no expiration date set for the LIPA rebate programs, although allocation of 2009 American Reinvestment and Recovery Act funding was crucial for the continued operation of the Solar Pioneer program due to increasing consumer interest (DSIRE, 2011a). LIPA allocated $107.9 million in solar incentives between 2000 and April 2011 (Photon, 2011b).

2.4.4.5. New York State Tax Credits and Exemptions

Property Tax Exemption

New York State offers a 15-year, 100% property tax exemption for grid-connected, net-metered residential, commercial, industrial and agricultural solar energy systems. The exemption covers an increase in assessed value attributable to the PV system. Systems must be installed by December 31, 2014. Municipalities, school districts, and counties may opt to not offer the exemption, however, the exemption is valid unless a local government opts out. To date, more than 150 local governments and school districts have opted out of this exemption (N.Y. Dept. of Taxation and Finance, 2011). The installed system must meet the NYSERDA eligibility criteria.

Sales Tax Exemption

New York also exempts the sale and installation of residential and multi-family residential PV systems from New York State sales and use taxes, under the Residential Solar Sales Tax Exemption. Local governments may also grant an exemption from local sales taxes. The exemption incentive has no expiration date (N.Y. CLS, 2005).

Residential State Income Tax Credit

Grid-connected, net-metered residential PV systems are eligible for the Residential Solar Tax Credit, subject to a 10 kW maximum for all residential installations, except for condos and coops (50 kW maximum).[30] The incentive is a personal income tax credit, equal to 25% of equipment and installation costs (capped at $5,000). Any excess credit may be carried forward for the following five taxable years (N.Y. CLS, 1997). This tax credit does not currently have an expiration date.

2.4.4.6. New York State Net Metering

The major investor-owned utilities are required to offer net metering on a first-come, first-served basis to customers, subject to technology, system size, and cumulative capacity restrictions.[31] The system size limit is 25 kW for residential solar and 2 MW for non-residential solar. Customer net excess generation is credited on the customer's next electricity bill at the utility's retail rate.[32] Residential customers are paid for any unused net excess generation at the utility's avoided-cost rate at the end of the annual billing cycle, whereas net excess generation from non-residential solar systems is carried forward to the next year. The aggregate capacity limit for net-metered PV, on-farm biogas, micro-CHP, and fuel cell systems (combined) is 1% of an investor-owned utility's 2005 electric demand. Individual utilities are authorized to set higher limits on aggregate net-metered capacity. LIPA has allowed for net metering that is similar to the state policy for investor-owned utilities (DSIRE, 2011c).

New York enacted legislation in June 2011 authorizing remote net metering by eligible farm-based and non-residential customer-generators.[33] Eligible customer-generators may combine meters on properties they lease or own, as long as the properties are within the same utility service territory and load zone. The

30 Per DSIRE's summary: "The language of the tax credit generally requires that PV systems conform to the state's net metering law, thereby limiting system size to 10 kW. In August 2008, the state net metering law was expanded by S.B. 7171 to permit net metering for residential PV systems up to 25 KW. It is unclear at this point whether the state intends for the new net metering limits to apply to the tax credit described above. The 2009 Solar Tax Credit Form IT-255 does not specifically address this issue."
(http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=NY03F&re=1&ee=1)

31 Net metering is a metering configuration that allows customer-sited generators to export power to the grid when it cannot be used onsite and be compensated at retail electric rates.

32 Net excess generation is the total amount of energy exported over the onsite power consumption during a given billing period.

33 Eligible customer-generators include agricultural customers who install solar or farm-waste energy systems, as well as non-residential customers who install wind energy systems.

properties do not have to be contiguous. Net excess generation credits will be allocated to the highest use meter first and excess credits will be carried forward from month to month (DSIRE, 2011c) .

2.4.4.7. Municipal Policies in New York State

Streamlined Permitting

Local governments may also support solar deployment through policies and incentives, such as expedited permitting for PV projects or other municipal code revisions. Riverhead, New York City and several Long Island counties are examples of local governments in New York State offering incentives for PV development.

The Town of Riverhead on Long Island provides a building permit fee discount for the installation of energy conservation devices on residential or commercial buildings. PV is specifically mentioned as an energy conservation device in the town code provision, which describes conservation devices as those that qualify for any federal, state or local tax exemption, tax credit, or tax rebate. Under this allowance the permitting fee for energy conservation devices is $150, whereas permitting fees for PV projects often totaled close to $1,000 prior to the code revision. The revision was enacted March 7, 2006, but was retroactively effective to July 1, 2005.

Additionally, the Long Island counties of Nassau and Suffolk are in the process of developing a streamlined permitting initiative for residential PV systems. The Long Island Unified Permitting Initiative, which was announced in September 2011, will implement a series of local solar policy best practices, including:

- Lowered permit application fees,
- A fast-tracked permitting application for solar,
- A central registry for solar projects(LIPA, 2011d).

Under it's '100 days of Solar' initiative, Consolidated Edison is working with New York City and NYSERDA to streamline the permitting process for PV in order to reduce the time it takes from application of permits to completed installation of systems from as much as one year down to 100 days. A Partnership lead by the City University of New York on behalf of New York City was successful in securing a DOE SunShot Rooftop Challenge award to aid in this effort through development of an online multi-agency process management portal. The Partnership will take the lessons learned and tools developed for this New York City effort and translate them to other major jurisdictions in New York State. These types of initiatives to provide local government permitting process improvements have been one of the major focuses of the U.S. Department of Energy's SunShot Initiative and are considered an increasingly important factor in PV system costs (U.S. DOE, 2011b; SunRun, 2011).

Local Sales Tax Exemptions

Local governments may also opt to grant residential solar systems an exemption from local sales taxes under guidance by state legislation exempting residential solar systems from state sales and compensating use tax (see *State Incentives* section above). New York City has acted on this sales tax incentive opportunity – all residential solar energy systems equipment and services are exempt from local sales tax as of December 2005 (New York City, 2005).

New York City Property Tax Abatement Program

New York legislation allows property tax abatement for PV expenditures for systems located on an eligible building in cities with a population of at least one million people. New York City is the only eligible city due to the minimum population requirement. The abatement incentive allows the building owner to deduct part of the PV installation costs from the owner's total real property taxes, hence the tax benefits are recouped through reduced property taxes on the host building. Utility real property is not eligible. The abatement amount is determined by the installation date (see Table 16), with the program expiring after 2012.

Table 16. New York City Tax Abatement Levels.

INSTALLATION DATE	ABATEMENT AMOUNT
Aug. 5, 2008 – Dec. 31, 2010	8.75% of eligible expenditures annually for four years
Jan. 1, 2011 – Dec. 31, 2012	5.0% of eligible expenditures annually for four years

The maximum incentive per year is $62,500 or the amount of real property taxes owed during the year. Unused balances cannot be carried forward to subsequent years. The amount of eligible expenditures is not reduced by tax credits, abatements, exemptions, or rebates; however, expenditures incurred using a federal, state, or local grant are not eligible (New York City, 2009).

2.4.5 PV Workforce Development

Since 2003, NYSERDA has invested millions of dollars in developing a robust network of photovoltaic training partners across the state to support the growth of NYSERDA's PV incentive program through a trained and qualified workforce. Today, NYSERDA has 31 PV training partners and training ranges from continuing education courses to credit courses to certificate and degree programs. Participants include installers, code officials, contractors, builders, engineers and architects. Working closely with the Interstate Renewable Energy Council (IREC) NYSERDA has helped its training partners pursue national accreditation for their PV programs and courses and certification for trainers.[34] Since January 2009, NYSERDA has conducted 64 solar workshops for 1,027 teachers in Grades 5-12, reaching approximately 77,000 NYS students. As the primary sponsor for the nation's premier Clean Energy Workforce Education

[34] All NYSERDA training partners can be found at http://www.nyserda.ny.gov/Events/Training-Map.aspx.

Conference (held four times since 2006), NYSERDA provides a forum for training institutions to learn from and share best practices with training experts from around the world.[35]

2.4.6 PV Technology and Business Development

In addition to the RPS incentives provided for the installation of PV systems, NYSERDA also provides funding through the System Benefits Charge (SBC) program to develop and commercialize solar technologies in New York State. A portion of these SBC funds are used to stimulate the development of technologies that will improve the performance and lower the cost of solar systems, as well as stimulate economic activity related to developing and manufacturing solar system components in New York. Since 2008, NYSERDA has provided almost $5 million to 13 different organizations to develop solar technologies. In addition, NYSERDA is providing $5 million to the Photovoltaic Manufacturing Consortium (PVMC) located at the College of Nanoscale Science and Engineering (CNSE) in Albany. The PVMC will stimulate the solar-energy panel market by producing superior thin-film solar cells and attract manufacturing to New York by providing partners with access to manufacturing-grade equipment and an opportunity to collaborate with other firms, as well as scientists at CNSE.

NYSERDA also supports a business growth and innovation program focused on establishing a strong environment for clean energy technology entrepreneurs in New York State and the translation of innovative ideas into investment worthy and commercially viable business enterprises. Early stage companies in the PV sector are an important target for the program. Programs work to capitalize on the strengths already inherent in New York, draw the attention of the investment and venture community to entrepreneurs in the state and provide focused business mentoring to companies with creative solutions to New York's energy needs. Expected outcomes include: Creation of a risk capital climate that increases the availability early stage investment for clean-energy technology start-up companies; establishment of a sustainable, long-lasting initiative to translate university research into a pipeline of clean energy technology company deal flow; formation of a network of business mentoring incubators and initiatives that increase the probability that innovative technologies will achieve commercial success and serve the needs of New York's market; and, facilitation of the formation of research and business clusters around areas of energy technology research where New York State holds a competitive advantage in the region.

2.5. The Global PV Market

The global PV supply chain consists of diverse array of commodities and system components, from raw materials, such as polysilicon, to finished products like modules, inverters, racking systems, and other balance of system components. This section discusses three of these major system elements from a global

35 To learn more about the next Workforce Education Conference in November 2012 visit: http://www.irecusa.org/irec-programs/workforce-development/new-ideas-national-conference/2012-cewec/.

supply perspective and also reviews current global capacities in the context of the 5,000 MW target of the Act.

2.5.1 Demand

Over the past decade, as national and state governments have developed and implemented PV incentive programs, the world market for PV has grown substantially. The following sections describe the market trends that have been fostered by these incentive programs.

2.5.1.1. Global Market Trends

Cumulative installed global PV capacity has grown significantly over the past decade. Largely driven by feed-in-tariffs in the European Union, global capacity has gone from less than 2 GW in 2000 to nearly 40 GW at the end of 2010 (EPIA, 2011). Figure 4 shows the breakdown of global cumulative installed capacity from 2000 to 2010.

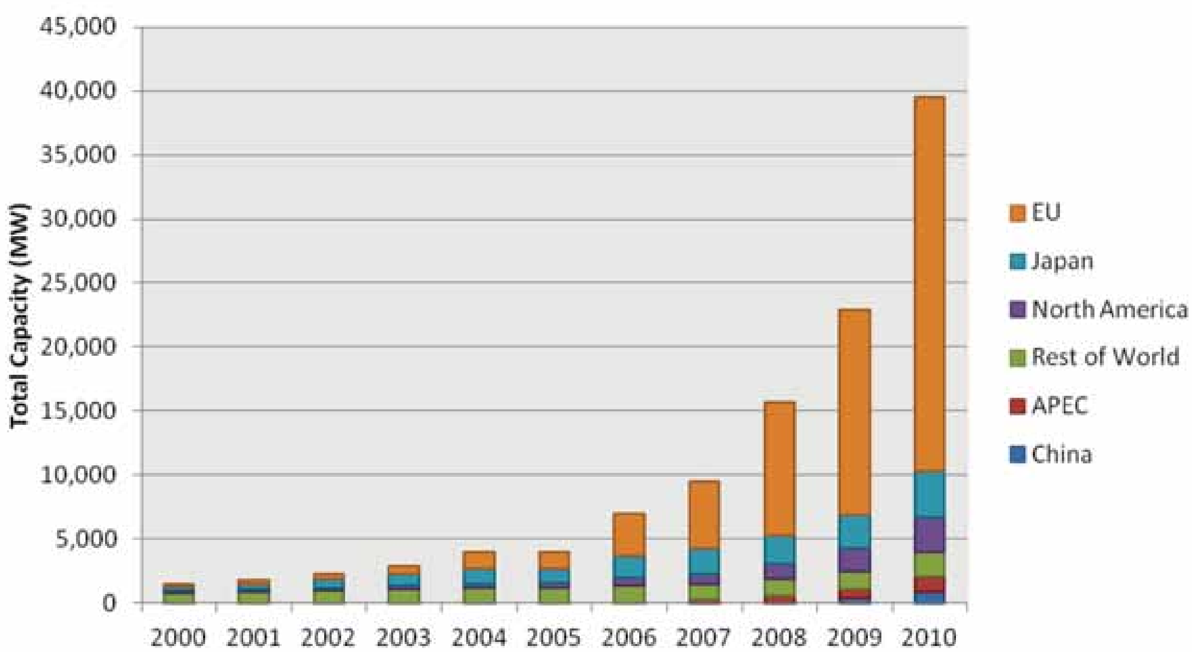

Figure 4. Global PV Cumulative Capacity by Region, 2000-2010 (EPIA, 2010)

The European Photovoltaic Industry Association (EPIA) estimates that 16.6 GW of PV was installed globally in 2010. Germany, Italy and the Czech Republic were the three largest PV markets in that year, accounting for 7.74, 3.74 and 1.42 GW of capacity additions respectively (Solar Buzz, 2010). These three markets represented more than three quarters of global PV demand in 2010. Germany has been the largest PV market for several years and demand from German feed-in tariff policies has significantly contributed to the decline in global module market prices. Both Germany and Italy were leading solar markets in 2011, with the U.S., Japan and China expected to round out the top five markets (Photon, 2011e). While the Chinese internal PV market has been limited in recent years, analysts are anticipating the implementation of a solar-specific feed-in tariff may significantly grow the Chinese market in the near term (Hook, 2011).

While recent global market growth has been substantial, industry analysts expect it to temper during 2012 as some large-scale European markets decrease incentive payments. Major changes include a planned decrease in the incentive payments in Germany and regulatory changes in the Italian PV feed-in-tariff.

A February 2011 survey of market analysts found significant variability in expected 2011 global PV market capacity additions. The most conservative analysts predicted an incremental 12.7 GW in 2011 while the most aggressive expected 25.4 GW in global additions (Hering, 2011). This significant variation in analyst estimates illustrates the dynamic nature of the global PV market as well as the inherent challenges in accurately anticipating demand in future years.

Long-term forecasts for global PV market growth from the EPIA estimate a total global installed capacity of between 131.3 GW and 195.9 GW by 2015. The EPIA also estimates global annual capacity additions of between 23.9 GW and 43.9 GW in 2015 (EPIA, 2011). This wide range in potential 2015 values is largely attributable to uncertainty around the long-term stability of national solar polices across the developed world and the unpredictable nature of solar technology costs.

2.5.1.2. United States Market Trends

Led by aggressive policies in a handful of states, the U.S. solar market has grown rapidly over the past few years. Falling installed costs, more favorable federal policies and state-level incentive programs have led to an expected 12 fold increase in installed capacity between 2006 and 2011. Analysts expect the U.S. market to exceed 1.8 GW of annual installation in 2011, the first time the U.S. market has exceeded 1 GW in installations (Photon, 2011a). Figure 5 shows the cumulative estimated installed PV capacity in the U.S. for the 2004-2010 period. Projected values for 2011 are also included.

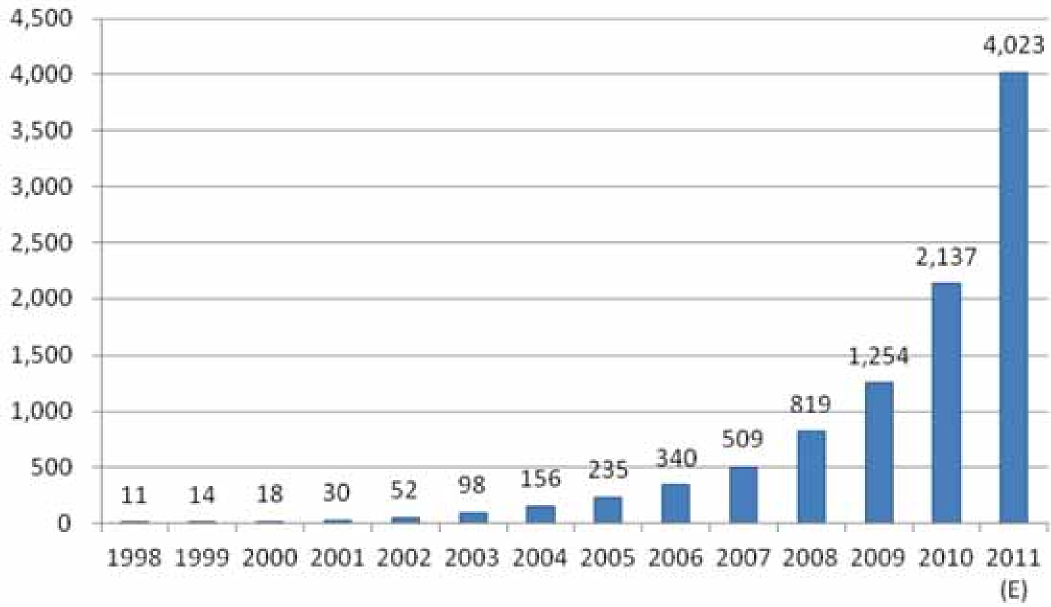

Figure 5. Installed U.S. PV Capacity 2004-2011 (expected) (Barbose, Darghouth, Wiser, & Seel, 2011; Photon, 2011a)

The U.S. has historically been led by the California market which comprised nearly 80% of the national PV market in 2004-2005 (Barbose, Darghouth, Wiser, & Seel, 2011) and accounts for around 30% of all U.S. installations today (Photon, 2011a). Figure 6 shows the expected relative installations by state for 2011.

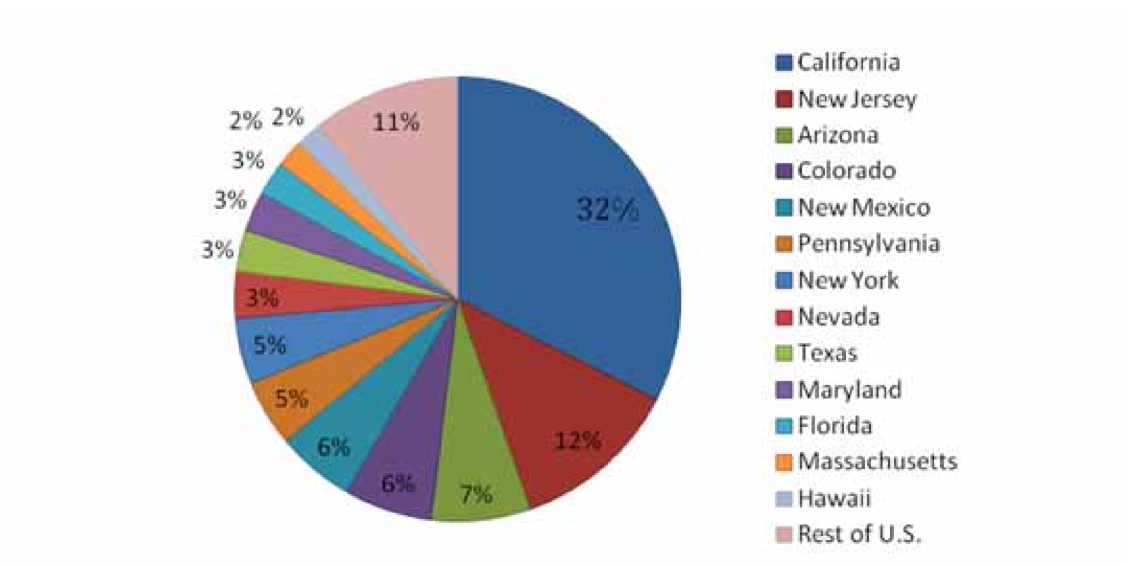

Figure 6. Expected U.S. State PV Relative Market Size for 2011 (Photon, 2011a)

State market growth has been highly dependent on policy support, and some states that formerly had leading positions in the U.S. had their markets collapse when policies were not renewed.[36] Additionally, several of the current leading solar markets are experiencing near-term challenges. SREC spot market prices in New Jersey recently declined sharply when the RPS obligation for 2012 was met early in the compliance year (SRECTrade, 2011). A similar SREC market over-supply has recently affected the Pennsylvania market. In both states, legislators are actively attempting to revise the current RPS/Alternative Energy Portfolio Standard (AEPS) laws to help maintain market growth and support their in-state solar industries (N.J. Senate, 2010; Bosworth, 2011). The Colorado PV market may also be experiencing a temporary slackening of PV demand as Xcel, a major state electric utility recently reduced incentives for its PV rebate program (Warren, 2011).

Future U.S. PV demand may be affected by the expiration of the 1603 Treasury grant program. Under current legislation, the Treasury grant program, which allows PV investors to opt for a 30% cash grant in lieu of the 30% ITC, will expire at the end of 2011. Industry analysts report that this program has been vital to the national PV market over the past few years as the current economic climate has made it difficult for developers to find tax-equity investors. While continued growth of the national solar industry is likely, given robust state policies and falling component costs, future industry growth scenarios may be affected by the expiration of this program if the availability of tax equity becomes a market constraint (EuPD Research, 2011).

2.5.2 Global Component Supply

The PV system supply chain includes a number of raw materials, components and finished products. PV technologies are broadly categorized into three types, monocrystalline, multicrystalline and thin-film. Crystalline solar panels are composed of multiple solar cells--individual silicon wafers that have been chemically transformed to generate DC electricity when exposed to light. PV cells are manufactured with integrated conductors that are strung together in a solar panel. The silicon wafers that are the building blocks for solar cells are manufactured from polysilicon, a manufactured commodity made from raw silicon. Monocrystalline and multicrystalline cells comprised over 85% of the global market in 2010.

Currently, global manufacturing capacity of each of these major PV system components exceeds global demand. In recent months, PV panel prices have seen significant costs declines as global manufacturing capacity has substantially outstripped demand. Similarly, polysilicon cost have seen dramatic price declines as new manufacturing facilities, planned during a market shortage in the late 2000s, have come online. Given these manufacturing capacity expansions, the global PV supply chain should be sufficient to meet the needs of the New York market as it grows to meet the goals of the Act. Appendix 1 discusses PV technologies, performance and market trends, as well as market trends in further detail.

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36 Connecticut had one of the leading US PV markets in the later part of the last decade before funding for its grant program expired.

2.6. New York PV Cost Baseline

PV module and component prices have remained dynamic during the last decade, with key components such as silicon, panels, and inverters at various times in critical over- and under-supply. However, there has been a steady, long-term price decline trend that is in line with expectations based on typical market experience curves. As the global PV market has grown, based on supportive national and local policies, manufacturers have made significant investments in expanding capacity. This has resulted in declines in PV panel prices and installed system costs. Figure 7shows the cumulative global installed PV capacity along with Navigant Consulting's global PV price index between 2000 and 2010. Of note, PV panel prices rose between 2004 and 2006 largely due to a global shortage of solar-grade silicon (Flynn & Bradford, 2006).

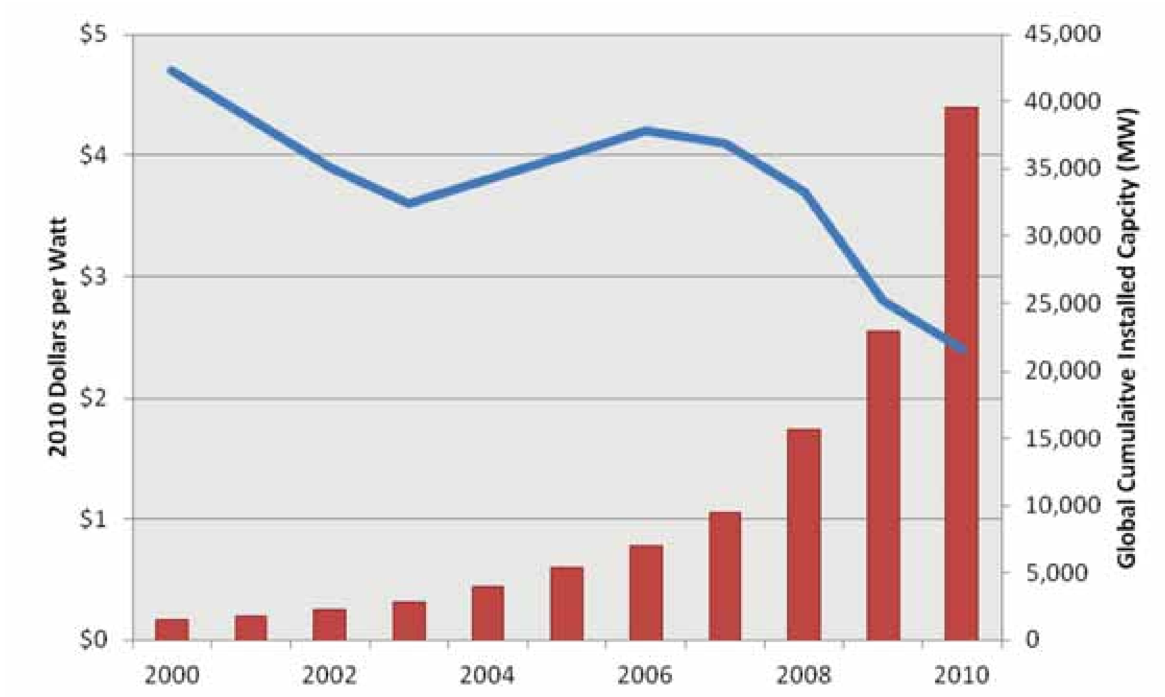


Figure 7. Navigant Consulting's Global PV Module Price Index 1998-2010 (Barbose, Darghouth, Wiser, & Seel, 2011) and EPIA 2015 Global Market Outlook (EPIA, 2011)

This global decreasing price trend has been mirrored both nationally and in the New York PV market. Figure 8 shows the capacity-weighted average installed cost for PV systems in the U.S. between 2000 and 2010 along with U.S. cumulative installed PV capacity.

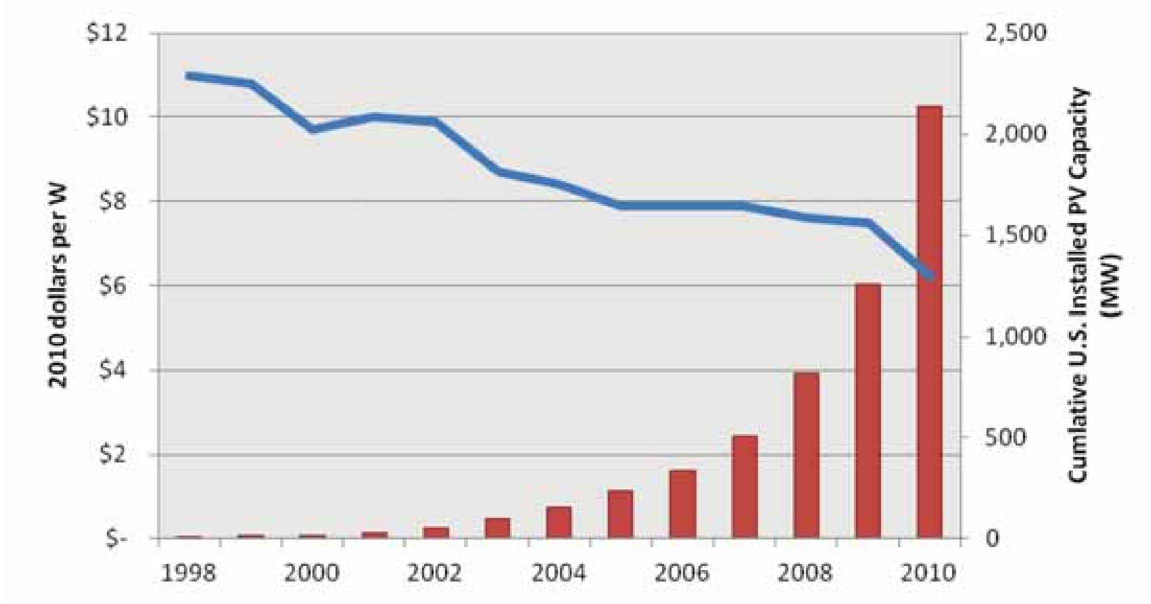
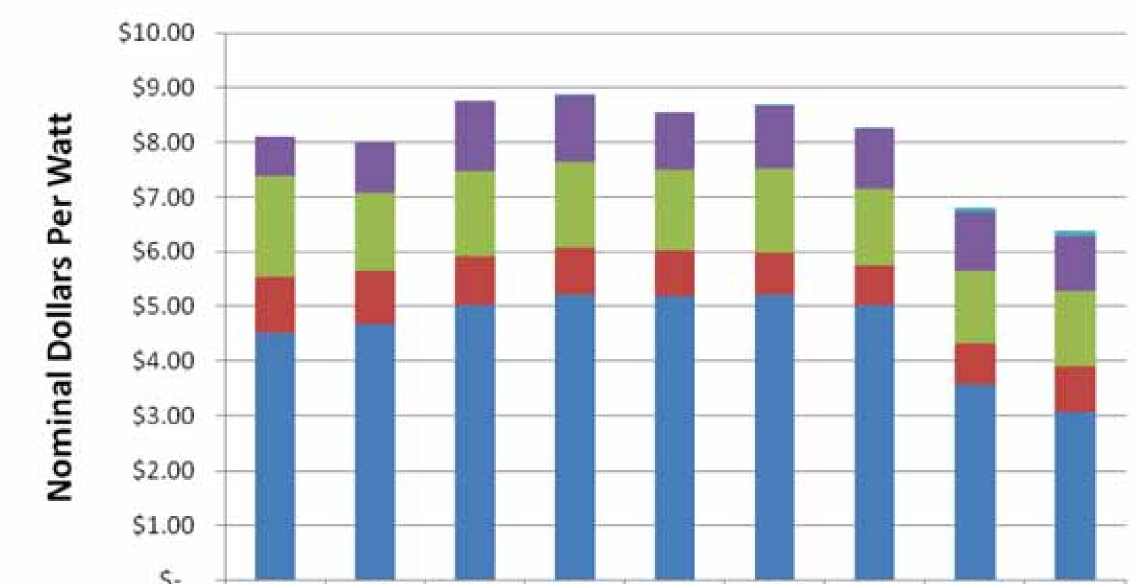


Figure 8. Capacity-Weighted Average Installed Costs in 2010 Dollars for PV Systems Installed in the United States 1998-2010 and Cumulative Installed U.S. PV Capacity (Barbose, Darghouth, Wiser, & Seel, 2011)

Mirroring both these global and national trends, PV installed costs have declined in New York over the past decade. Figure 9 shows weighted average installed cost for the 3,543 PV systems in the NYSERDA upfront incentive program database that have comprehensive data for all system components. As the figure shows, the recent global decline in solar module costs has led to a similar decline in installed costs in New York.



	2003	2004	2005	2006	2007	2008	2009	2010	2011
Other $/W	$-	$-	$-	$0.01	$-	$0.00	$0.01	$0.05	$0.08
BOS $/W	$0.72	$0.93	$1.30	$1.22	$1.07	$1.15	$1.11	$1.07	$1.02
Labor $/W	$1.87	$1.44	$1.56	$1.58	$1.47	$1.53	$1.41	$1.34	$1.38
Inverter $/W	$1.01	$0.98	$0.89	$0.85	$0.83	$0.76	$0.73	$0.75	$0.84
Module $/W	$4.51	$4.67	$5.02	$5.22	$5.19	$5.22	$5.01	$3.57	$3.06

Figure 9. PV System Prices by Component in the NYSERDA Upfront Incentive Program Database 2003-2011[37]

To the extent that data for 2011 only includes upfront incentive applications for the 167 completed systems that were submitted prior to July 1, 2011, it is likely that installed cost may significantly decline over the last half of 2011 as global module market surveys have shown steep declines in pricing over the last 12 months. SolarBuzz, a consulting firm that published module price market surveys, reports a 27.6% decline in retail module prices from October 2010 to October 2011 (SolarBuzz, 2011).

Installed costs across New York vary by region. As previously mentioned, the LIPA territory has a larger relative PV market size than other load zones in the state and New York City has some unique installation, permitting and interconnection challenges which increase installed costs. Figure 10 shows average PV system prices for residential systems in the LIPA territory and 0-10 kW PV systems in the other load zones in this study. As the figure shows, during the early part of the last decade, LIPA systems were typically less

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[37] Data is for the 3,734 approved and completed PV systems that have complete data for all four cost categories in the NYSERDA rebate database. Costs are categorized by system approval year and not year completed as this likely best reflects current market prices. “Other” cost category includes all costs not accounted for in BOS (balance of system), Labor, Inverter and Module categories and may include permitting and interconnection costs.

expensive than other regions of the state, however during the past few years, prices in LIPA and the rest of the state, excluding New York City, have converged.

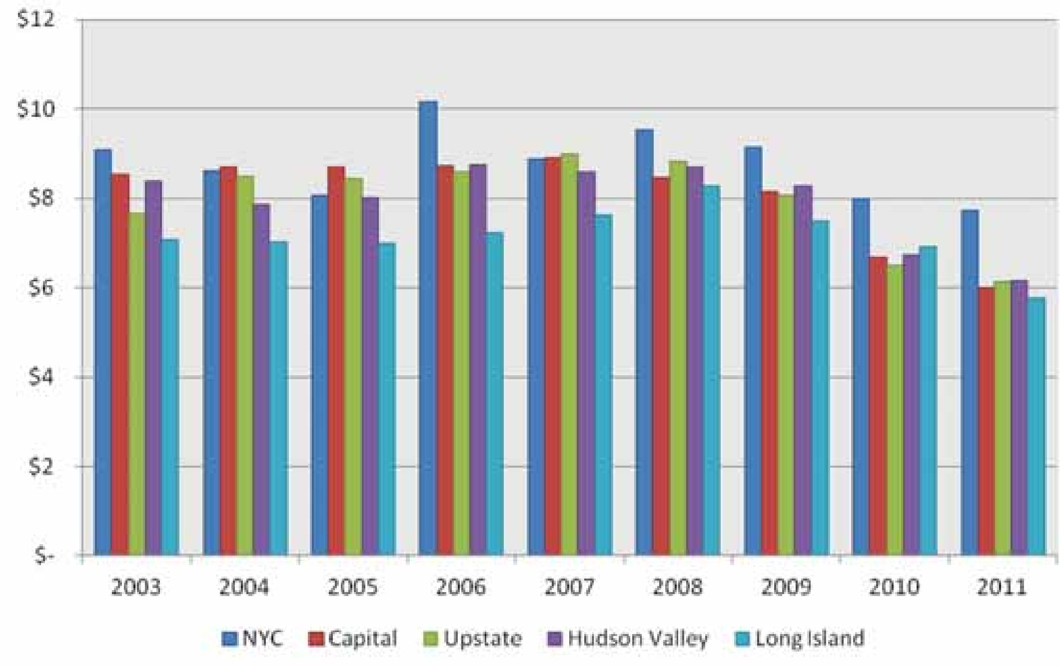

Figure 10. Residential PV System Average Costs by Load Zone 2003-2011[38]

Similarly, installed prices for small commercial systems have varied considerably by region. Figure 11 shows weighted average system cost per watt by year for PV systems greater than 10 kW and to 100kW in the NYSERDA program database as well as installed cost for the LIPA Solar Entrepreneurs program. As the figure shows, installed cost differences by region have been less consistent for this project size class, with New York City installations showing a smaller costs premium over the rest of the state in recent years.[39]

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38 LIPA data from LIPA staff. Other load zones are from NYSERDA database. NYSERDA values are for systems between 0 and 10kW. LIPA data is for the residential Solar Pioneers program.

39 Note: Installed cost values for the early years of the program may be significantly affected by small sample sizes in particular regions.

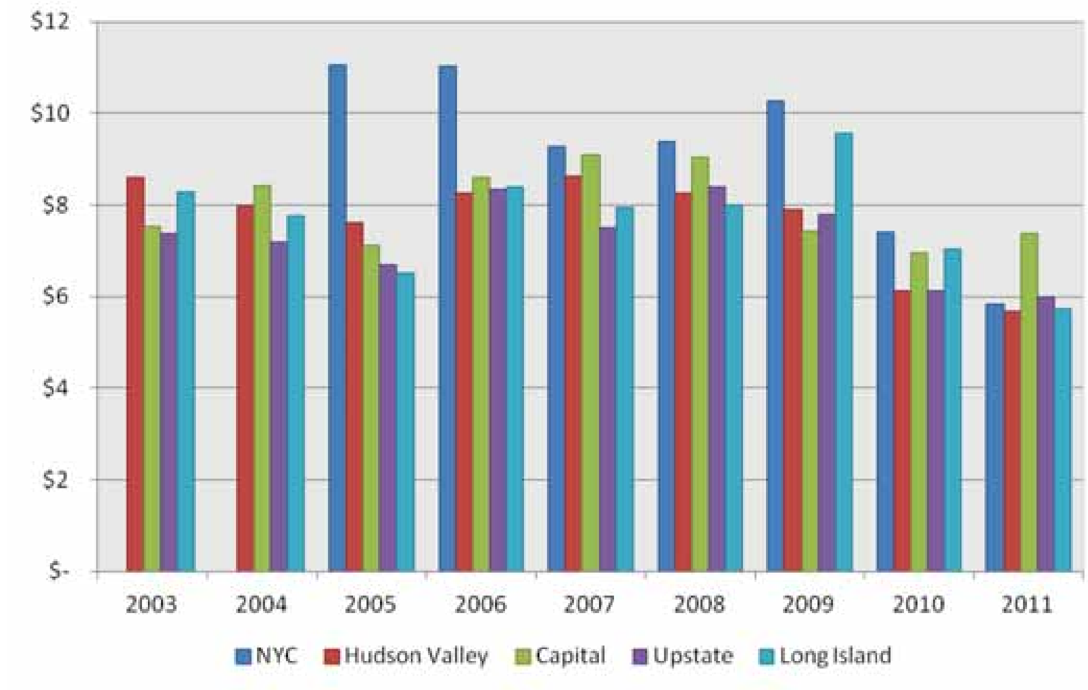

Figure 11. Small Commercial PV System Weighted Average Costs by Load Zone 2003-2011[40]

2.6.1 Comparative Analysis of New York PV Market Costs

As the New York solar market has grown over the past decade, installed cost of PV has tended to converge with national average costs data. Lawrence Berkeley National Laboratory (LBNL) produces an annual study of the U.S. solar market and provides national installed cost data based on data sets provided by state incentive programs (Barbose, Darghouth, Wiser, & Seel, 2011). While the published national data does not exactly mirror the size classes defined in the NYSERDA analysis, it does provide a useful benchmark for comparing the New York state market to national averages.

Figure 12 and Figure 13 show the national installed costs from the LBNL survey data as well as data from the NYSERDA solar programs database. Since the national figures are published as 2010 dollars, averages from the NYSERDA data set have been inflation adjusted. Additionally, the NYSERDA data is displayed both including and excluding New York City installations. This is particularly critical for the small commercial classes, as several high-cost PV installations in the 2005-2006 data years significantly influence the state-wide average.

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40 LIPA data from LIPA staff. Other load zones data are from NYSERDA database. NYSERDA values are for systems between >10 and 100kW. LIPA data is for the small business Solar Entrepreneurs program.

As the figures indicate, PV systems in the New York market were significantly more expensive than the national average during the middle part of the last decade. This may be attributable to New York's relatively small market size during that time period.[41] As the data indicates, this New York premium has disappeared for the 2010 installation year for the small commercial class and residential systems installed in 2010 as part of the NYSERDA program now cost below the national average for both the New York City and non- New York City NYSERDA cases.

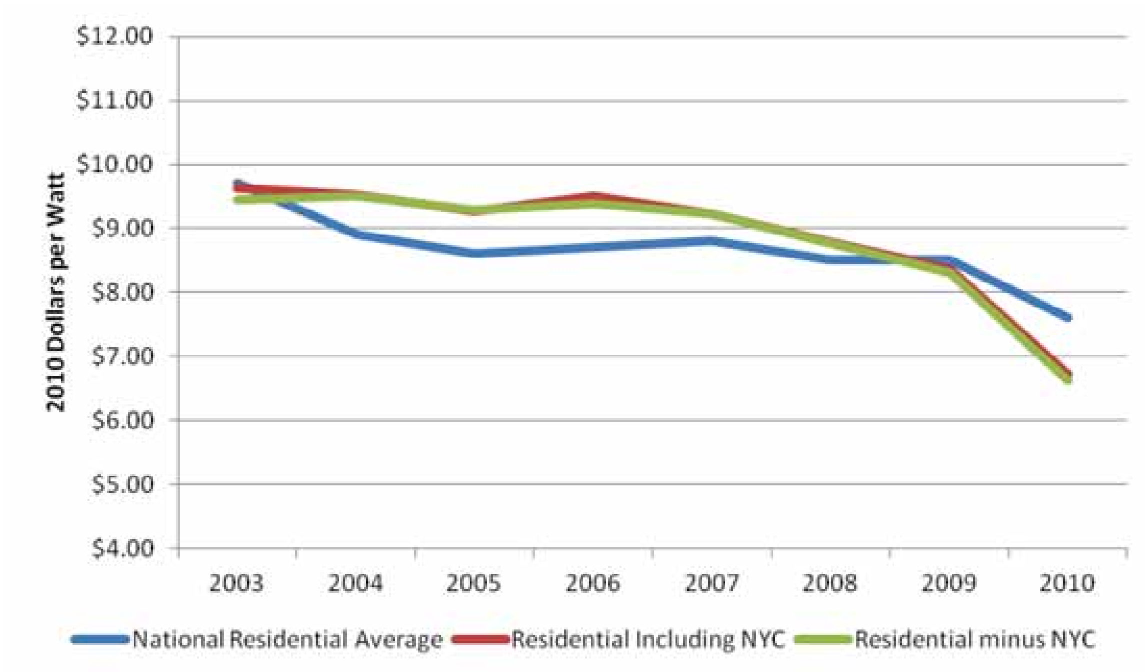

Figure 12: Comparison of National and New York Residential PV System Historic Cost Trends (NYSERDA, 2011a; Barbose, Darghouth, Wiser, & Seel, 2011)

41 The New York City solar market also has more building integrated installations than other regions of the state. Building integrated PV (BIPV) incorporates PV cells into structural elements of a building, allowing the solar installation to serve multiple purposes beyond power generation. Because of the multi-functionality, BIPV installations are typically more expensive than non-BIPV solar installations.

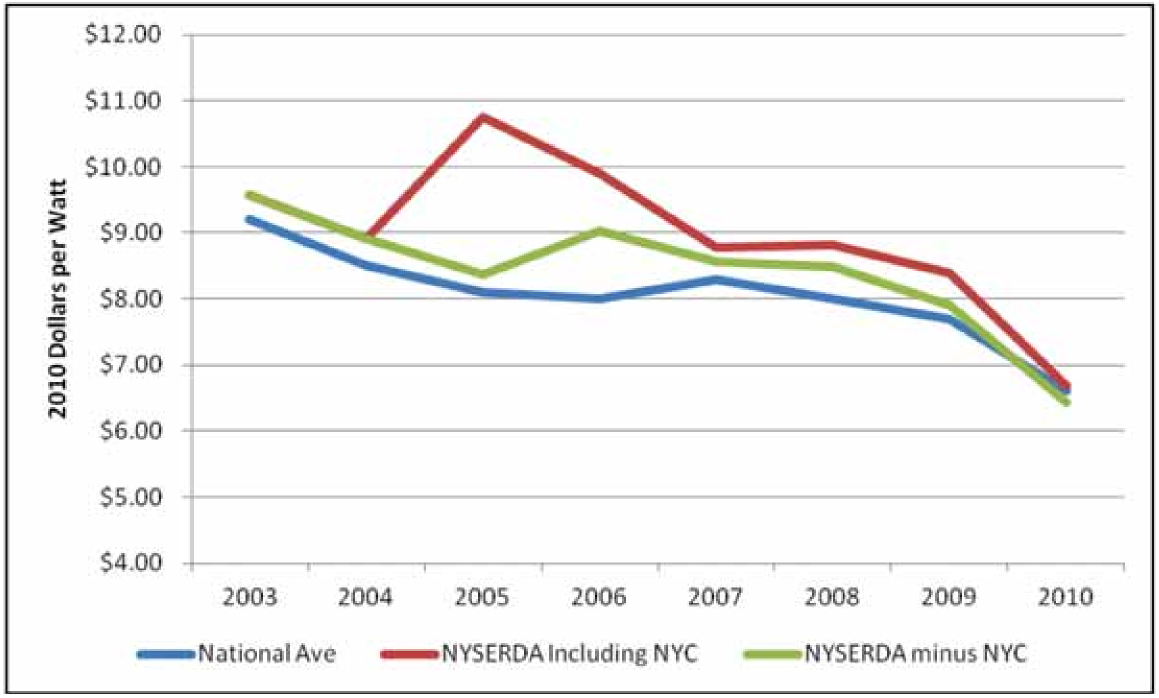

Figure 13: Comparison of National and New York PV System Historic Cost Trends (NYSERDA, 2011a; Barbose, Darghouth, Wiser, & Seel, 2011)

3. PV COST PROJECTIONS

3.1. Introduction

Market expansion has led to steep cost declines in PV technology. It is projected that PV costs will continue to decline over time as markets continue to grow, technology improves, barriers are removed, and installations become more efficient. This chapter examines the future cost of energy from PV and compares it against future electricity grid prices and against the cost of energy from other renewable sources.

Key findings:

- Global PV costs have recently declined sharply as markets have grown.
- The primary drivers of total PV cost to New York are the future cost of installed PV (hardware and labor) and the federal incentive level. The location of installations and system sizes were secondary cost drivers.
- By 2025 the cost of PV is expected to significantly decline, where the Base Case installed cost will range from $2.50 per W for MW-scale systems to $3.10 per W for the residential-scale system, in nominal dollars. For the Low Cost Case, the range is $1.40 per W to $2.00 per W and for the High Cost Case the range is $2.90 per W to $4.30 per W.
- On average, the PV levelized cost of energy (LCOE) is forecasted to decline by approximately 50% in 2020 and by approximately 60% in 2025. These LCOE results, although annual, represent a long-term view, and are not intended to provide a fundamental analysis of near-term market prices. Near-term prices should be monitored in order to determine if a low cost trajectory is warranted.
- PV is not expected to achieve wholesale parity during the analysis period (2013 thru 2049) in any cost future.
- Retail parity may be achieved, and will occur sooner in NYC than in other regions of the state. This suggests a greater leverage of state dollars in NYC. In a low-cost PV future there is parity in NYC by 2017.
- PV cost of energy is expected to be more expensive than large-scale onshore wind energy and will most likely be more expensive than off-shore wind in 2025. The comparison of PV to wind energy is instructive as wind is presently the only other technology with both a high installation growth rate and substantial additional resource potential (other resources may represent lower cost supply, but in limited quantities).
- PV cost of energy may be competitive with small-scale wind energy and green field biomass technologies by 2025.
- Due to the differences between what is measured by cost of electricity and by the value of the energy produced, it is recommended that a full study of the costs and benefits of other renewable energy technologies be conducted to better inform renewable energy policy development.

- Federal incentives will play a critical role in the magnitude and predictability of future PV prices. In addition, the "SunShot" goal articulated by the U.S. DOE is an aggressive and meritorious goal that, if achieved, would substantially reduce PV cost and change the benefit-cost equation. It is recommended that New York should take particular interest in – and action on – these federal issues which are critical to future PV costs to consumers.
- PV energy facilities in New York are expected to be developed under a range of ownership and financing arrangements. While private ownership by third parties offering PPAs to site hosts is expected to represent the dominant structure, it is also important to think of the range of LCOE outputs in this section as a representation not only of the range of potential installed costs but also of the range of financing and ownership options available to the market.

This chapter is organized as follows:

- Section 3.2 describes the methodology used to derive LCOE estimates.
- Section 3.3 discusses PV installed cost estimates and projections and their derivation.
- Section 3.4 describes post-construction operation and maintenance cost projections and their derivation.
- Section 3.5 describes the assumptions regarding future Federal and New York State incentives embedded in the LCOE forecast.
- Section 3.6 describes financing assumptions.
- Section 3.7 describes PV system performance projections.
- Section 3.8 summarizes the LCOE projections.
- Section 3.9 provides an LCOE comparison between solar and other renewable energy technologies.
- Appendix 4 contains further detail on PV LCOE projections in both real and nominal terms.

The installed cost and LCOE forecasts in this Section are based on a series of long-term trends developed by the US Department of Energy and other industry sources. Given that a majority of the PV is deployed after 2020, the use of long-term trends is critical for this study. These forecasts are not intended to predict with precision the market's short-term supply and demand dynamics which play a major role in determining PV's installed cost and LCOE over the next few years. Based on this, it is expected that the 2012, 2013, and 2014 forecast values may differ from actual market prices in these years. Therefore, the forecasts in this chapter should be evaluated based on their predictions of solar energy costs in the 2020 to 2025 period.

3.2. Methodology

LCOE forecasts are developed for PV systems installed through 2025, for each of the four standard system sizes more fully defined in Chapter 4. Inputs to the LCOE analysis were developed from a review of publicly available information. Inputs include capital and operating costs, system performance, and incentive and financing parameters. Inputs were developed for each project size and region. High, Low and Base inputs were developed for the financing, installed costs and incentive inputs. The assumptions and sources for each input are documented in detail in the remainder of this chapter.

Several factors not addressed in this analysis, but which are referenced below, include a cost forecast of building-integrated PV (BIPV), the cost and production impact of adding single- or dual-axis tracking capability to PV systems, and an explicit analysis of the cost trend of the different PV technologies described in Chapter 1.3.

3.2.1 LCOE Scenarios

For groupings of capital costs, financing and federal and state incentive assumptions, three scenarios were developed to allow the projection of three trajectories of PV LCOE for each project size in each region. In order to establish the range of potential LCOE outcomes, the following scenarios were established:

- **Low Cost Future:** The low installed cost trajectory was grouped with the high incentives case and low financing cost case.
- **High Cost Future:** The high installed cost trajectory was grouped with the low incentives case and high financing cost case.
- **Base Cost Case:** A base case was run for all project sizes and locations, using average and central-estimate inputs.

The Base PV Scenario utilizes the Base Cost Case LCOE. The High Cost and Low Cost scenarios offer the ability to conduct sensitivity analysis when modeling specific policy options.

3.2.2 Calculating LCOE: The CREST Model

Once the input development process was complete, LCOE projections were developed using the National Renewable Energy Laboratory (NREL) *Cost of Renewable Energy Spreadsheet Tool* (CREST) solar model. The model and supporting documentation are available at the NREL web site (NREL, 2011b). Model outputs include the cost of energy on a nominal levelized basis.

CREST was developed as a publicly available and transparent tool to aid policymakers in estimating renewable energy costs for various public policy purposes, such as establishing cost-based PBIs such as standard offers. The model is designed to calculate the cost of energy, or minimum revenue per unit of production needed, for the modeled renewable energy project to meet its equity investors' assumed minimum required after-tax rate of return. The model was developed in Microsoft Excel, so it offers the user a high level of transparency including full comprehension of the underlying equations and model logic.

The CREST model allows the user to specify unique levels of capital and operating cost detail. With respect to capital costs, CREST allows the user a range of input options from a simple $/Watt value to a highly detailed cost component list. For this analysis, the "intermediate" approach was selected allowing for the incorporation of separate estimates of interconnection costs from the other installed cost components. The intermediate approach breaks out components of the operations and maintenance costs, such as insurance and property taxes. The CREST model also makes it easy for the user to conduct sensitivity analyses, including variations in incentive payment durations, and the ability of equity investors to efficiently utilize tax incentives.

3.3. Installed Cost Assumptions

3.3.1 Initial Equipment and Installation Costs

For each of the four sizes of PV systems, an estimate of initial installed costs in calendar year 2010 was developed. Installed cost includes the cost of all components, installation labor, and development costs (engineering, permitting, etc.). As discussed in Section 2.5.2, for 2010, global equipment supply and demand were in rough balance, following a period of shortage and elevated prices, and preceding the 2011 period of surplus which has suppressed prices below what appear to be a long-term cost trend. Use of 2010 as opposed to 2011 as the initial year of the forecast is intended to avoid biasing the forecast towards the current oversupply conditions that are resulting in dramatically falling PV prices in the near-term, which appear only partially related to manufacturing cost trends.[42]

Economies of scale in PV project development are evident in historical data from a variety of data sources. In addition, some incentives are only available to certain types of installations, such as the New York State tax credits and exemptions described in Section 2.4.4.5. As a result, cost projections are differentiated for each standard system size.

Historical data also suggests that installed costs differ somewhat by region within New York State, for example, with a higher cost of doing business in the New York City area. Installed cost forecasts were made for each of the four project sizes, for three representative regions in New York State: Long Island, New York City, and the Rest of New York. The Rest of New York installed cost forecast was applied in the

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42 The use of 2010 cost data was also driven by the fact that approximately six months of 2011 installation data were available at the time this analysis was conducted, a quantity insufficient to rely on for this analysis.

CREST analysis to the Upstate, Capital and Downstate regions. The sources of information used to estimate the 2010 installed costs for each project size and location are described below.

- **Residential and Small C&I:** For the residential and small commercial sizes, NYSERDA Power Clerks data were used to derive 2010 installed costs. For residential systems, a weighted average cost was calculated for all systems approved in 2010 between 3kW and 7kW. For small commercial systems, a weighted average cost was calculated for systems between 30kW and 50 kW approved in 2010. The data supports use of the same cost for Upstate and Long Island regions, and a premium in New York City of 23% for residential installations and 10% for Small C&I, which are utilized for this study.
- **Large C&I:** The NYSERDA database contained limited data on the large commercial scale systems. For this system size, weighted average costs for PV systems approved in 2010 in the Massachusetts and California project databases was calculated.[43] This average was used as a proxy for installed non-NYC installed costs for this system size. A NYC 2010 cost estimate was developed for this system class by multiplying the non-NYC price by the NYC cost premium (10%) observed for Small C&I installations in the NYSERDA data set.
- **"Rest of New York" MW-scale:** Limited data for MW-scale PV systems is available for estimating 2010 project costs in New York State. A number of national sources were considered to develop a best estimate for installed cost for a reference 2MW system in New York State in 2010, including: an NREL Q4 2010 solar cost model, the 32MW Brookhaven Labs installation, LBNL's Tracking the Sun IV, a 2009 DOE expert survey, the Mass SREC database, industry analyst estimates a Greentech Media 2010 national cost estimate, MW-scale project average costs from NJ's PSEG, reported costs from a 10MW installation in New Jersey and stakeholder input from a recent Rhode Island standard offer rate setting process.
- **Long Island and NYC MW-Scale.** In order to account for potentially higher MW-scale PV installed costs in the LIPA territory based on assumed higher land acquisition costs, a 5% installed cost premium was assumed for Long Island MW-scale projects, and a 10% installed cost premium was assumed for NYC MW-scale projects.

Based on the these assumptions and data sources, the initial costs in 2010 dollars per kW (DC) described in Table 17 were developed and used as the anchor point for development of future cost trends.

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43 Note: For both the residential and small commercial scale systems, average costs for non-NYC projects in the NYSERDA database for 2010 are within 1% of the combined average costs found in the Massachusetts and California databases for the same period. Based on this strong correlation, it was assumed that installed costs for Large C&I outside of NYC would mirror cost in the Massachusetts and California data sets.

Table 17. Estimated Costs of New York PV Projects in 2010 (2010$)

PROJECT SIZE & LOCATION	2010 COST ($/kW$_{DC}$)	SOURCE
Residential Upstate/LIPA	$6,590	2010 3-7kW NYSERDA weighted average cost
Residential NYC	$8,134	2010 3-7kW NYSERDA weighted average cost
Small Commercial Upstate/LIPA	$6,177	2010 30-50kW NYSERDA weighted average cost
Small Commercial NYC	$6,765	2010 30-50kW NYSERDA weighted average cost
Large Commercial Upstate/LIPA	$5,289	2010 MA - CA weighted average cost
Large Commercial NYC	$5,793	Rest of NY x (Rest of NY /NYC) Ratio (110%)
MW-Scale	$4,300	Estimate from several sources
MW-Scale LIPA	$4,515	5% premium for increased land costs
MW-Scale NYC	$4,710	Rest of NY x (Rest of NY /NYC) Ratio (110%)

3.3.1.1. Sales Tax as a Component of Installed Costs

New York exempts the sale and installation of residential solar energy systems from the state's sales and compensating use tax. The law also allows, but does not require, municipalities to grant exemptions from local sales taxes. Seventeen counties currently offer a the local sales tax exemption, while 29 counties levy local sales taxes and 15 counties include some municipalities which offer the exemption and some that do not. Due to the range of sales tax treatment and the fact that residential system cost estimates are based on data obtained from NYSERDA through the Power Clerks program, this analysis assumes that the residential cost data are inclusive and representative of the current sales tax environment in the state.

The sale and installation of commercial solar energy systems (of any size) are subject to state and local sales and compensating use taxes.[44] Due to the fact that the data underlying the commercial and MW-scale cost estimates is derived from states that also assess sales taxes on solar energy systems, this analysis assumes that the commercial and MW-scale cost data are a reasonable representation of the current sales tax environment in New York. While sales tax values vary from state to state, the overall range of uncertainty for solar installed costs is wider than any potential bias introduced through use of this assumption.

44 Based on internet research and discussions with the NYS Department of Taxation and Finance.

3.3.2 Installed Cost Trends

The 2010 cost estimates were trended over time using three indices crafted based on analysis of several publicly-available forecasts.[45] For forecasting purposes, it is assumed at any given time during the forecast horizon that whatever PV technology is least costly in each year will comprise 100% of the sales in that year.[46] With these data, three installed cost cases were developed, a *base case* for use in modeling scenarios and a *high cost* and *low cost* case, for use in sensitivity analyses.

Because each published cost trend had a 2010 installed cost that differed from 2010 New York State costs, each published trend was normalized to create an index for which 2010 equaled 100%, declining in subsequent years.[47] In addition to the trends cited, another cost forecast was developed by assuming that the goals of DOE's SunShot initiative – an aspirational forecasts targeting all-in installed costs of $1 per Watt before 2020 - were fully realized in the marketplace by 2022, five years after the DOE's target for successful demonstration of technology and best practices capable of a 75% price decline. This adjusted *SunShot Commercialization trend* is used as the low-cost trend applied to each system size and location.

The three costs trends were modeled based on the following installed cost trajectories:

- **Low Cost**: Sunshot Commercialization
- **Base**: 2009 DOE Expert Survey
- **High Cost**: 3% Cost Decline from 2010 Values

Figure 14 shows, for the residential case, the cost trends crafted for use in this study compared to all researched cost forecasts.

45 These included: EIA's Annual Energy Outlook 2011 PV cost assumptions, the IEA's international PV cost roadmap, the DOE's SunShot initiative, DOE's SETP 2009 PV cost forecast, a 2009 DOE expert survey, and non-public data from Bloomberg New Energy Finance.

46 Analysis of the costs trends of individual PV technologies was beyond the scope of this report. For example, the variety of BIPV applications and lack of cost uniformity made the inclusion and forecasting of BIPV costs too complex for this analysis. Technology-specific research is warranted, however, and may yield further insights about future costs.

47 As no forecasts had costs defined for each analysis year, costs for years between reported cost years were interpolated. Similarly, cost trends that did not go out to the 2025 analysis year were extrapolated based on their existing trend, except as otherwise described herein.

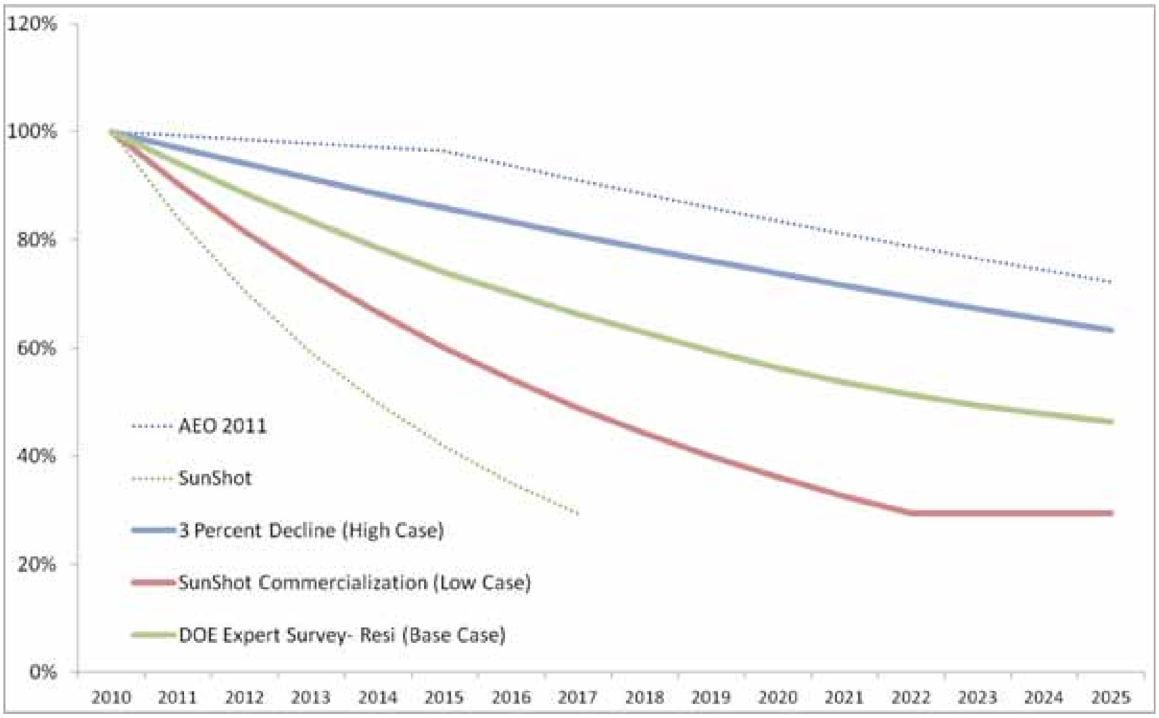

Figure 14. Residential Real Cost Trends from Various Forecasts, 2010-2025

To illustrate the relationship between installed cost projections for the four different standard project sizes, Figure 15 compares the Base Case cost trend on a real basis for the Rest of New York region.

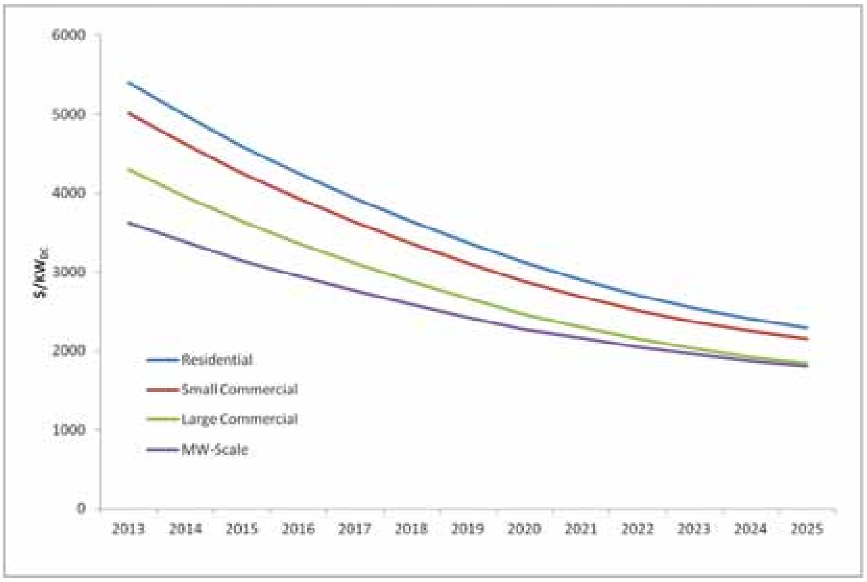

Figure 15. Installed Cost Forecast: by Category, Upstate Region, Base Case, 2011-2025 (2011 $/kW$_{DC}$).

A detailed summary of installed cost forecasts by project size, location and year are available for each Cost Case in Appendix 4.

3.3.3 Interconnection Costs

Interconnection costs were treated separately from the remainder of the 2010 installed cost estimate. Initial 2010 interconnection costs for residential (4 kW) systems were assumed to be $375 per installation, based on the current legislated limit. For larger systems (40, 400 and 2 MW) interconnection costs were assumed to be 4% of the project's total 2010 installed costs. These values represent about half the estimated upper-bound interconnection cost for large commercial systems as reported by LIPA staff. Interconnection cost values were assumed to decrease between 2010 and 2025 on a real dollar basis to 50% of their 2010 value for Residential installations and to 75% of their 2010 value for Commercial and MW-Scale. The remaining installed costs were trended over time as described above.

3.3.4 Inverter Replacement

As noted in Appendix 1, inverters were once considered the least reliable and most failure-prone component of PV systems. As the market has matured, manufacturing quality has improved and inverter manufacturers are increasingly providing extended warranties on their products. Many of the top-tier inverter manufacturers are now offering customers the option to purchase 20-year warranties on their products. Recent research[48] has shown that customers are increasingly taking advantage of such inverter

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48 Based on the authors' research interviews, vetted through a stakeholder process, conducted in late 2011 during the development of PV standard offer ceiling prices for the state of Rhode Island.

warranties purchased in advance of commercial operation. These warranties typically guarantee the inverters for 20 years. The cost of inverter warranties (assumptions shown in Table 18) were therefore modeled as an up-front cost.

Table 18. Up-Front Inverter Warranty Cost Estimates

	INVERTER WARRANTY (2010$/kW)
Residential (4 kW)	$150
Small C&I (40 kW)	$125
Large C&I (400 kW)	$110
MW-Scale (2000 kW)	$100

3.4. Post-Construction (Operation and Maintenance) Cost Projections

Post construction costs for PV systems, often referred to broadly as operations and maintenance costs, were broken into four categories including the actual costs of operating and maintaining the systems, insurance costs, property taxes and lease payments (or equivalent). Assumptions for these cost categories were based on interviews with industry stakeholders, reviews of existing literature, and internet research. The basis for projections for each category are described as follows:

- **Operations and Maintenance (O&M):** Based upon a fall 2011survey of PV costs conducted as part of a recent Rhode Island proceeding to establish long-term Standard Offer contract prices for Distributed Generation.
- **Insurance:** Same as for O&M.
- **Property Tax:** New York state law exempts PV systems of all sizes from property tax assessments. However, the law also allows any municipality to opt out of this exemption. It was assumed that such exemption is available and effective only in the Low Cost Case, and only through year-end 2014 when the current law is set to expire. After 2014 in the Low Cost Case and in all years in the Base and High Cost Cases, all municipalities are assumed to opt out of the property tax exemption. There is a dearth of information (public or otherwise) regarding the rates at which PV installations will be assessed property taxes or the payments negotiated in lieu of a rate-specific property tax calculation. The nascent market for large PV installations in New York provides little data. In New York State, property taxes are typically linked to the income-generating potential for the landowner and not the income-generating potential for the asset owner (which for solar installations are frequently distinct). To this end, the emerging solar industry in New York may be more likely to follow the payment in lieu of taxes (PILOT) path than any historic formula. For the purpose of estimating LCOE, a first-year of

commercial operation property tax rate of $35/kW is assumed to decline 10% each year thereafter. The current New York City property tax abatement for solar installations is not applied to this analysis, as it is set to expire in 2012 and is not expected to be renewed.

- **Lease Payments**: Assumed not to apply to residential systems but were modeled for the three larger systems.

The initial assumptions for these cost categories are summarized in Table 19 in 2011 dollars per kW_{DC}. Operations and maintenance expenses and insurance premiums are escalated each year by the assumed rate of inflation. Property tax payments, by contrast, are assumed to start at $35/kW for all projects constructed during the analysis period, and are assumed to decline 10% per year throughout the project's useful life.

Table 19. O&M Cost Assumptions (2011$)

	O&M ($/kW$_{DC}$)	INSURANCE (% of total installed cost)	PROPERTY TAX ($/kW$_{DC}$, Yr 1)[49]	LEASE/SITE PMTS ($/kW$_{DC}$)
Residential (4 kW)	$22	.4%	$35	$0
Small C&I (40 kW)	$22	.4%	$35	$10
Large C&I (400 kW)	$22	.4%	$35	$15
MW-Scale (2000 kW)	$24	.4%	$35	$22

3.5. Federal and State Incentives

Beyond their current sunset date, the continued presence, form and magnitude of Federal and New York state incentives described in Chapter 1.3 is uncertain. Three federal incentive scenarios were defined, as follows:

- **High Incentives-** Indefinite extension of the 30% Investment Tax Credit (ITC);
- **Low Incentives-** ITC reverts to 10% after the current 12/31/2016 sunset date, and continues indefinitely; and
- **Base-** ITC continues at 30% through 12/31/2016 and then phases down to 15% over a 5-year period, remaining at this reduced level indefinitely.

In all cases, federal depreciation benefits are assumed to remain in effect indefinitely. Bonus depreciation is not assumed in any case, however.

49 Declining at 10% per year thereafter.

State Incentives

While a New York State tax credit equal to the lesser of 25% of installed costs or $5,000 is available to homeowners installing residential solar systems, this analysis assumes that residential installations are third-party owned and therefore not eligible for this state tax credit.

3.6. Financing Assumptions

The Residential, Small C&I, and Large C&I financing assumptions used in projecting PV LCOE reflect an environment in which the majority of projects are expected to be constructed, financed and operated by third parties that sell the facility's output to the site host through a long-term power purchase agreement (PPA). While some early adopters are likely to own the solar projects installed on their facilities, it is expected that, in order to achieve substantial market penetration, the third-party ownership model will become most prevalent. Third party owners' presumed access to a wider range of capital sources and ability to efficiently monetize Federal tax and depreciation incentives explains this observed trend. In recognition of the likelihood that a portion of projects in each size category will be built and owned through other means, the range of outcomes created by the low, base and high cost case forecasts can also be viewed to bound the potential variability in LCOE created by differences in ownership structure. The MW-Scale financing and incentive assumptions in the LCOE analysis reflect projects that are built either on the third-party ownership model or by Independent Power Producers (IPPs).

Three financing cases were defined: a *base*, *low financing cost* and *high financing cost* case. Financing assumptions include ownership structure, capital structure (proportions of equity and debt) and related obligations and fees. The Base Case inputs provide a reference case for the calculation of solar LCOE and for the evaluation of the cost of potential future New York State solar energy policies. Financing assumptions were determined through consultation with stakeholders, review of NREL's Renewable Energy Finance Tracking Initiative (REFTI) reports, and model optimization. Private sector ownership is assumed in all cases.

Capital Structure and Cost of Capital

For all financing scenarios, a debt/equity ratio of 50/50 was employed, with an assumed 15-year debt term. The cost of debt and equity capital, and the presence of a lender's fee, were varied by case and are shown in Table 20, Table 21 and Table 22 for the Base, High and Low financing cost cases, respectively.

Table 20. Base Case Financing Assumptions[50]

	DEBT INTEREST RATE	COST OF EQUITY	LENDER FEE
Residential (4 kW)	6.0%	12.0%	3%
Small C&I (40 kW)	6.0%	12.0%	0%
Large C&I (400 kW)	6.0%	12.0%	3%
MW-Scale (2000 kW)	6.0%	12.0%	3%

Table 21. High Cost Financing Assumptions[51]

	DEBT INTEREST RATE	COST OF EQUITY	LENDER FEE
Residential (4 kW)	7.5%	13.5%	3%
Small C&I (40 kW)	7.5%	15.0%	0%
Large C&I (400 kW)	7.5%	13.5%	3%
MW-Scale (2000 kW)	7.5%	13.5%	3%

The smaller increase in cost of equity in the large C&I and MW-scale categories, compared to the small C&I category, is explained by an assumed re-optimization of project financing in the United States after the expiration of the Federal Investment Tax Credit. It is assumed that a dramatically larger investor pool (compared to the relatively small number of tax equity investors) will create competition which drives down the cost of investment capital for larger solar installations. Because residential installations are assumed to be dominated by third-party leases from companies whose structure is established to optimize financing, the same assumptions are applied to Residential. In contrast, Small C&I are assumed to be owned by hosts whose cost of equity is based on competition for resources among other investments available to them.

Table 22. Low Cost Financing Assumptions[52]

	DEBT INTEREST RATE	COST OF EQUITY	LENDER FEE
Residential (4 kW)	5.0%	10.0%	3%
Small C&I (40 kW)	5.0%	10.0%	0%
Large C&I (400 kW)	5.0%	10.0%	3%
MW-Scale (2000 kW)	5.0%	10.0%	3%

50 Assumptions based on interviews with industry stakeholders, reviews of existing literature, and internet research.
51 Ibid.
52 Ibid.

Transaction and Financing Costs

In general, the installed cost trajectories in this section are assumed to include all equipment and installation costs but exclude all financing, transaction, and other soft costs. As such, the Large C&I and MW-scale projects were assumed to incur the equivalent of three months of construction interest at 5% on total project costs, as well as a 3% lender fee on the total amount borrowed. Residential projects are assumed not to incur interest during construction, but the 3% lender fee is applied as a proxy for the fees associated with financing a large portfolio and not individual residential projects. All projects are assumed to fund a 6 month debt service reserve and 6 month operating expense reserve at the time of project financing[53].

Costs Assumed Capitalized for Financing

The costs that are assumed capitalized, and are modeled in CREST as financed according to the above assumptions are the sum of the projected installed costs, construction interest, reserves and the up-front lenders fees.

3.7. System Performance Assumptions

Forecasted annual energy production is required for calculation of the PV LCOE projections. Such production is determined as a function of projected annual capacity factor and system degradation over time.

3.7.1 Capacity Factors

NREL's PV Watts online solar performance calculator was used to develop annual net capacity factors for each of the four system sizes and five New York zones (PVWatts, 2011). PV Watts allows the user to input a derate factor or use the PV Watts default derate factor. The derate factor in PV Watts is a composite factor that incorporates several factors that can reduce a solar facilities performance. The components are included in Table 23 below and include inverter losses, PV nameplate DC rating, soiling, etc.

53 Ibid.

Table 23. PV Watts Derate Factors (PVWatts, 2011)

COMPONENT DERATE FACTORS	COMPONENT DERATE VALUES	RANGE OF ACCEPTABLE VALUES
PV module nameplate DC rating	0.95	0.80 - 1.05
Inverter and Transformer	0.92	0.88 - 0.98
Mismatch	0.98	0.97 - 0.995
Diodes and connections	0.995	0.99 - 0.997
DC wiring	0.98	0.97 - 0.99
AC wiring	0.99	0.98 - 0.993
Soiling	0.95	0.30 - 0.995
System availability	0.98	0.00 - 0.995
Shading	1.00	0.00 - 1.00
Sun-tracking	1.00	0.95 - 1.00
Age	1.00	0.70 - 1.00

Assumptions for appropriate PV Watts inputs were derived based on the performance and siting of the state's existing PV fleet. This analysis assumed that all projects are on a fixed axis (no single- or double-axis tracking).[54] The PV Watts inputs used are shown in Table 24.

54 While some projects may improve their net production by adding tracking, this improvement comes with higher capital costs. The costs of tracking are not reflected in the data used to establish the installed cost projections, as northeastern PV projects have rarely employed tracking.

Table 24. Derate Factors for New York Facilities

	TILT	ORIENTATION	TRACKING[55]	DC RATING DERATE	INVERTER EFFICIENCY	OTHER DERATES (PVWATTS DEFAULTS)	AGGREGATE
Residential	30°	+/- 30 d from due south	No	95% (PVW default)	92%	.88	0.77
Small C&I	12°	+/- 10 d off due south	No	97%	94%	.88	0.80
Large C&I	12°	+/- 10 d off due south	No	97%	95%	.88	0.81
MW-scale	20°	Due south	No	100% (rating warranty)	95.5%	.88	0.84

The resulting capacity factors are shown Table 25 below.

Table 25. Projected New York Capacity Factors

REGION	NYISO ZONES	PV WATTS CITY	CAPACITY FACTOR, DC			
			RES	SM C&I	LG C&I	MW-SCALE
Upstate	A, B, C, D, E	Average of Buffalo, Rochester, Binghamton, Syracuse, Massena	12.53%	12.70%	12.89%	13.79%
Capital	F	Albany	12.98%	13.09%	13.23%	14.28%
Downstate	G, H, I	NYC	13.63%	13.73%	13.87%	14.96%
New York City	J	NYC	13.63%	13.73%	13.87%	14.96%
Long Island	K	NYC	13.63%	13.73%	13.87%	14.96%

3.7.2 Degradation factor

The production capacity from all projects was assumed to degrade by 0.5% per year for the entire 25-year assumed useful life.

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55 It was assumed that none of the systems installed in New York will include tracking. While 1 or 2 axis tracking would increase the capacity factors for the PV systems, the tracking systems will add to the installed costs. Given little evidence of many tracking systems installed in New York State or other Northeastern states, it does not appear that the extra expense of a tracking system creates a positive return in New York.

3.8. LCOE Projections (CREST Outputs)

LCOE estimates are presented in Figure 16 through Figure 18 for all project sizes within the Upstate Region and for each year of the analysis period, 2011 through 2025. Base Case results are presented, along with a Low Cost Scenario (in which the low trajectory of installed costs are grouped with lower-cost financing assumptions and more aggressive federal incentives), and a High Cost Scenario (in which the high trajectory of installed costs are grouped with higher-cost financing assumptions and conservative assumptions about federal incentives). Appendix 4 includes tables providing LCOE data points for all locations, project sizes and years , in nominal dollars as well as the (real) 2011$ shown here.

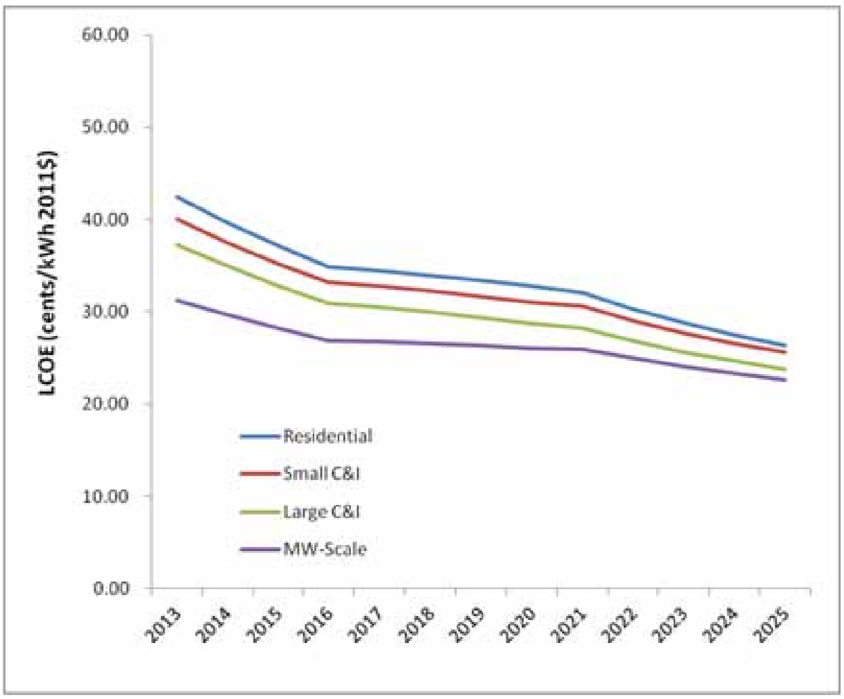

Figure 16. Base Case LCOE: (Including 5-year Phase-Down of 15% ITC Value) Upstate (2011$ ¢/kWh)

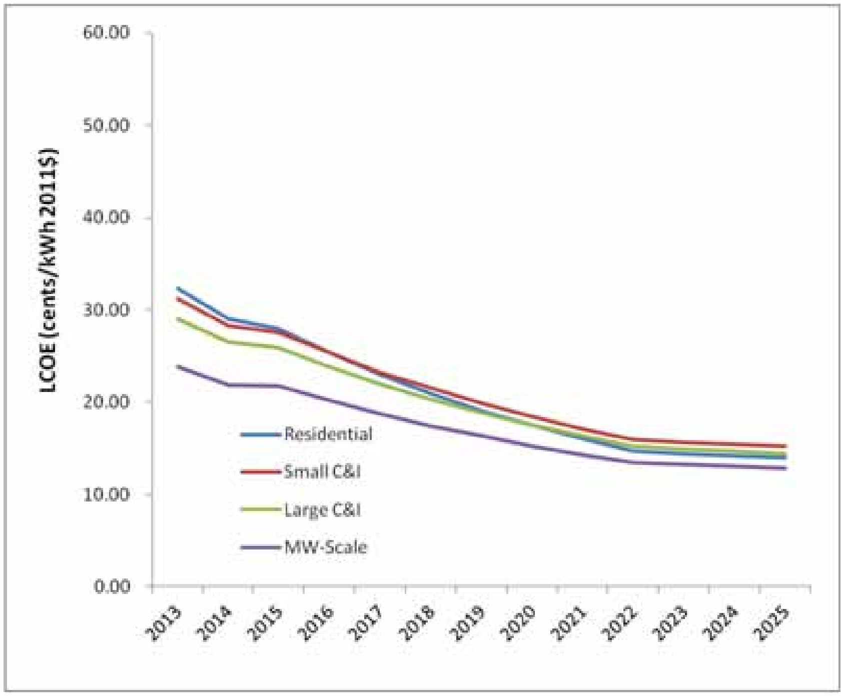

Figure 17. Low Cost Future Scenario LCOE: (Current Fed. Incentives Extended Indefinitely) Upstate (2011$ ¢/kWh)

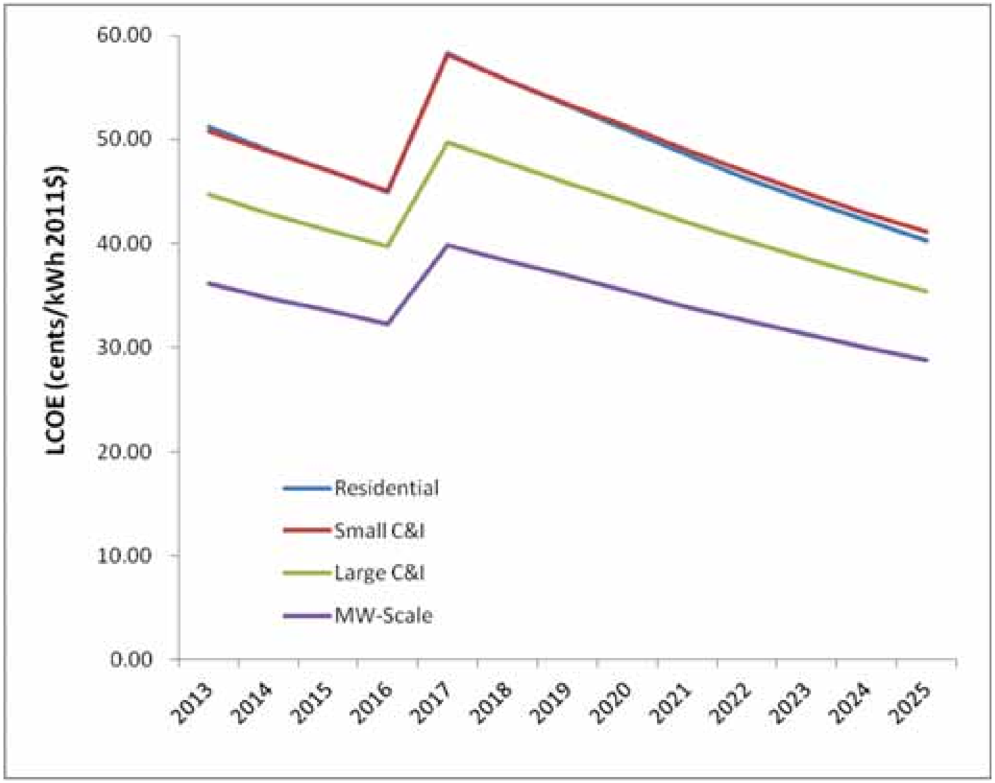

Figure 18. High Cost Future Scenario LCOE (Current Fed. Incentives Cease after 2016) Upstate (2011$ ¢/kWh)[56]

As described earlier with respect to the near-term forecast of solar installed costs, the LCOE estimates provided in the early years of this forecast are not based on or intended to predict market conditions in 2012 and 2013. Therefore, the forecasts in should be evaluated based on their predictions of solar energy costs in the 2020 to 2025 period.[57] When comparing the results of this New York analysis to reports of solar energy costs across the nation, it is important to remember that solar installations built in other parts of the country – and in the southwest in particular – typically have a greater available solar resource and benefit from greater economies of scale than are available to projects in New York.

Finally, several factors point to the possibility that the cost of solar energy may not continue to decline at the rates seen in recent years. First, the opportunity to qualify for an exchange of the Investment Tax Credit (ITC) for a cash payment from the US Treasury expired on January 1, 2012. At the same time, the 100% Bonus Depreciation incentive was reduced to 50% for 2012, and will sunset entirely for projects

56 Note: The Federal ITC reverts to 10% after the current 12/31/2016 sunset date.

57 With respect to current market information regarding the cost of solar energy, data that become available as this report went to press suggested that solar projects currently proposed for the northeast may soon be completed at contract prices well below the first several years of the base case LCOE forecast. This potential outcome is acknowledged, but it is important to note that there is no guarantee that these projects will be able to secure financing and achieve commercial operation under these new market prices.

operational on or after January 1, 2013.[58] In addition, the cash payment exchange of the ITC provided short-term access to a wider pool of investment capital, and thereby created a competitive environment that helped to drive down the cost of capital and PV's LCOE along with it. On top of these factors, debt interest rates have been at historic lows – although due to lender requirements, access to this low-cost capital is not inevitable, and a global recession and economic crisis has left the solar equipment market in near-term over supply.

3.8.1 Comparisons with Avoided Costs

As a long-term forecast, this study also considered the question of if and when solar LCOEs will achieve parity with average wholesale and retail electricity costs in New York.[59] Based on this analysis, illustrated in Figure 19 and Figure 20 below, not even the Low Cost Future LCOE projection is expected to achieve parity with wholesale electricity prices by 2025. Retail rate parity may be achieved, however, especially in NYC, where electricity prices exceed all other regions in the state. In a low-cost PV future retail parity is expected in NYC by 2017. This suggests that state incentives may create more leverage in this region.

Energy prices will continue to rise beyond 2025, as projected in this study. For systems installed prior to 2025, which have not reached retail rate parity prior to 2025, these illustrations show how their LCOE may fall below retail prices during their lives (reducing rate impacts). When future LCOEs fall below retail prices, the conditions for potential market transformation become apparent, where direct incentives may no longer be required.

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58 The cash payment removes all barriers to monetizing the ITC, and bonus depreciation provides a boost to tax equity returns by further accelerating depreciation benefits.

59 The derivation of retail and wholesale market value of PV production is described in Chapter 5.

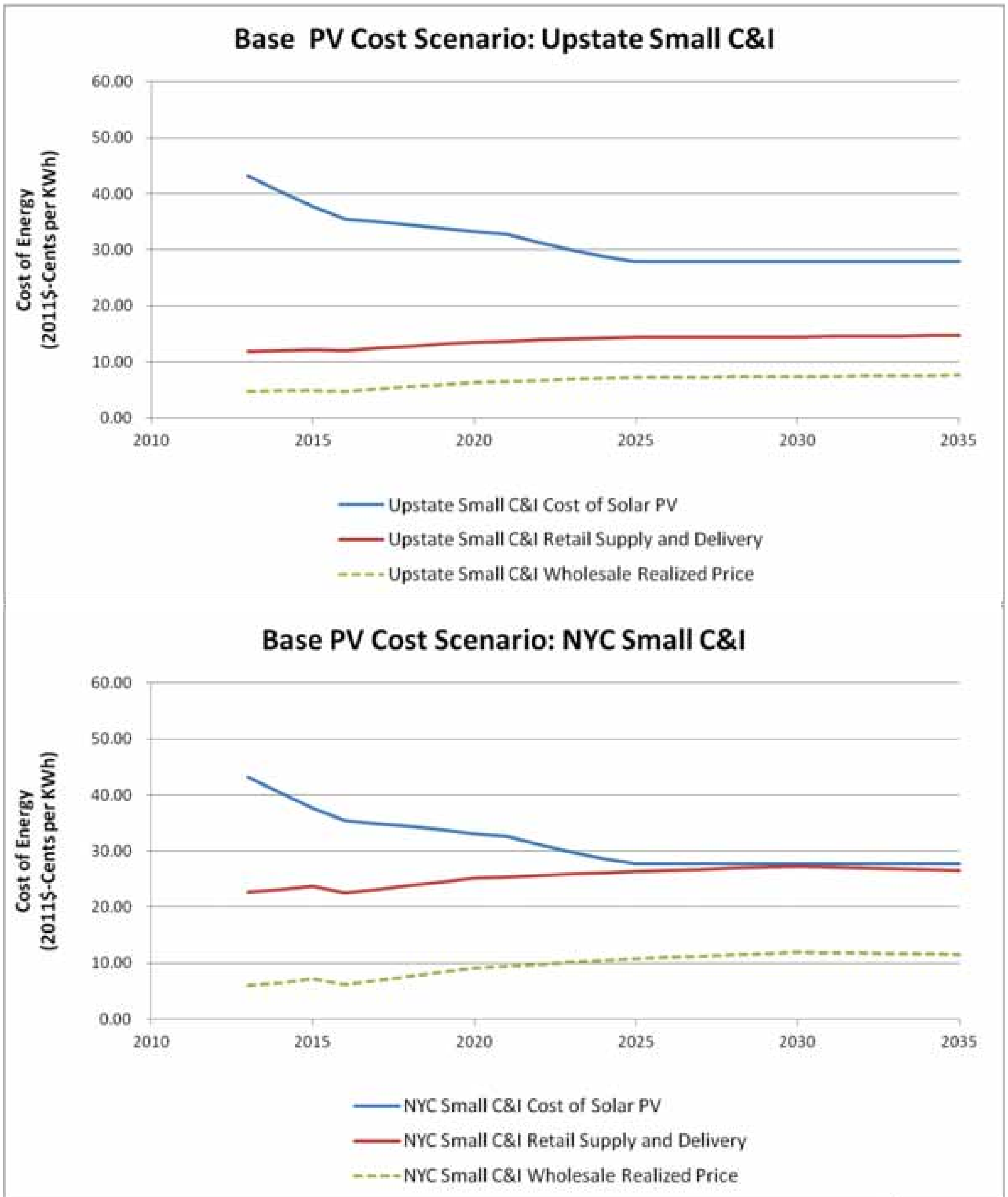

Figure 19. Illustrative Retail and Wholesale Rate Parity, Base PV Costs[60]

60 Post-2025, the blue line representing PV LCOE is held constant to show when the LCOE for systems installed in 2025 will fall below retail rates.

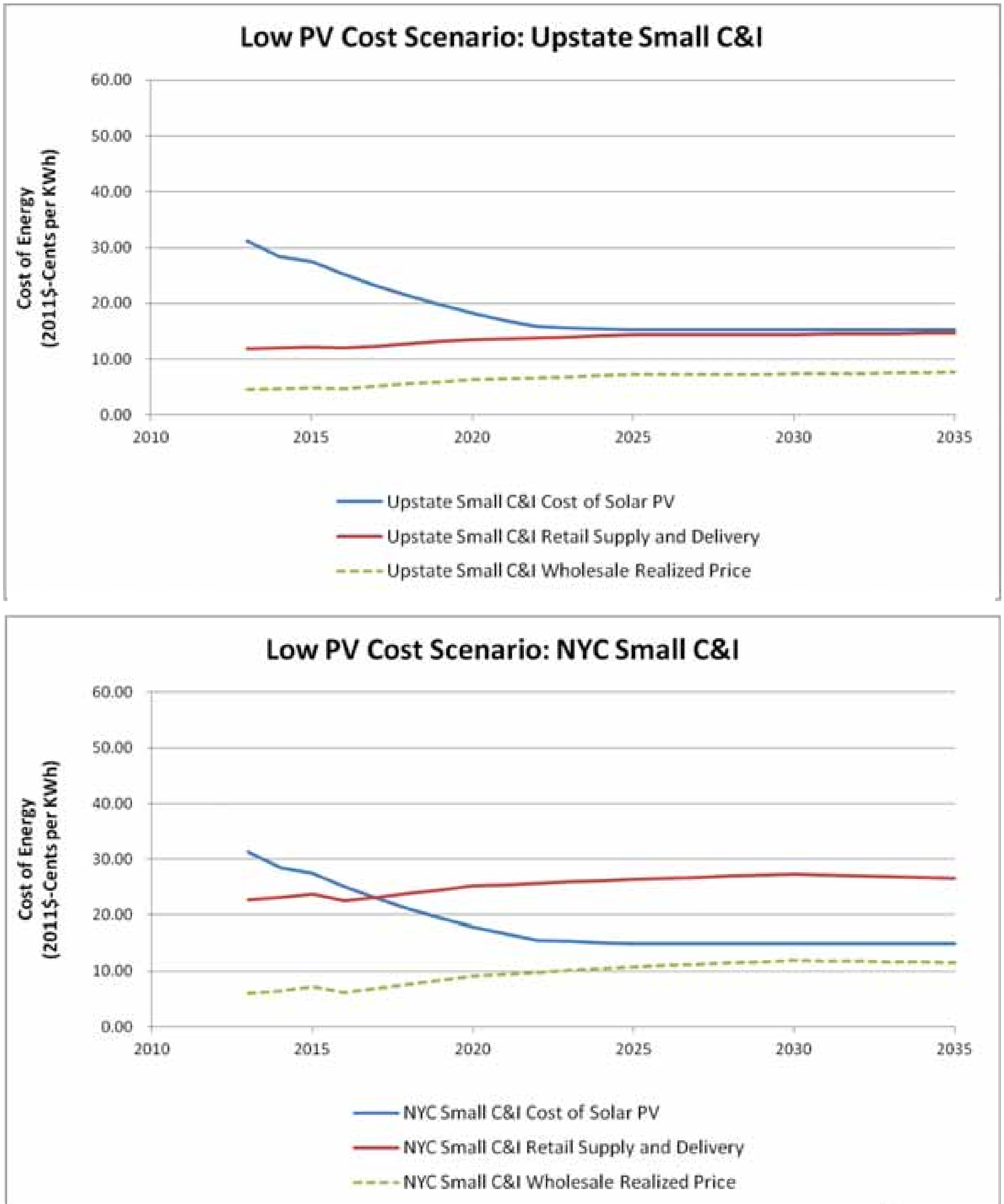

Figure 20. Illustrative Retail and Wholesale Rate Parity, Low PV Costs[61]

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61 Post-2025, the blue line representing PV LCOE is held constant to show when the LCOE for systems installed in 2025 will fall below retail rates.

3.9. Cost of Energy Comparison with Other Renewable Energy Technologies

This section provides an LCOE comparison between solar and other renewable energy technologies over the analysis horizon of this report. This analysis uses the same methodology and technology-specific CREST modeling tools to generate comparable LCOE metrics.

The comparison of PV to wind energy may be more instructive than to other technologies, as wind is presently the only other technology with both a high installation growth rate and substantial additional resource potential. Wind energy is likely to be the marginal – and therefore price-setting – resource for compliance with policies that require the development of new, large scale renewable energy facilities. Other resources may represent lower cost supply in limited quantities. This quantity-oriented view is an important consideration in the policy-making process and is not adequately represented by looking at a comparison of LCOE alone.

Figure 21 compares LCOE, by technology, in 2025. In the Base Cost Case, the PV LCOE (shown here for a MW-Scale project in New York's Capital Region) is forecast to have a lower LCOE than small new hydroelectric resources but a higher LCOE than all other modeled resources. In the Low Cost Future, the PV LCOE is forecast to also have a lower LCOE than the offshore wind high case, small onshore wind, and Greenfield biomass. All other resources, including large onshore wind and the offshore wind low cost case, are forecast to have lower LCOEs than the PV Low Cost Future.

The comparison of PV to wind energy may be more instructive than to other technologies, as wind is presently the only other technology with both a high installation growth rate and substantial additional resource potential. Wind energy is likely to be the marginal – and therefore price-setting – resource for compliance with policies that require the development of new, large scale renewable energy facilities. Other resources may represent lower cost supply in limited quantities. This quantity-oriented view is an important consideration in the policy-making process and is not adequately represented by looking at a comparison of LCOE alone.

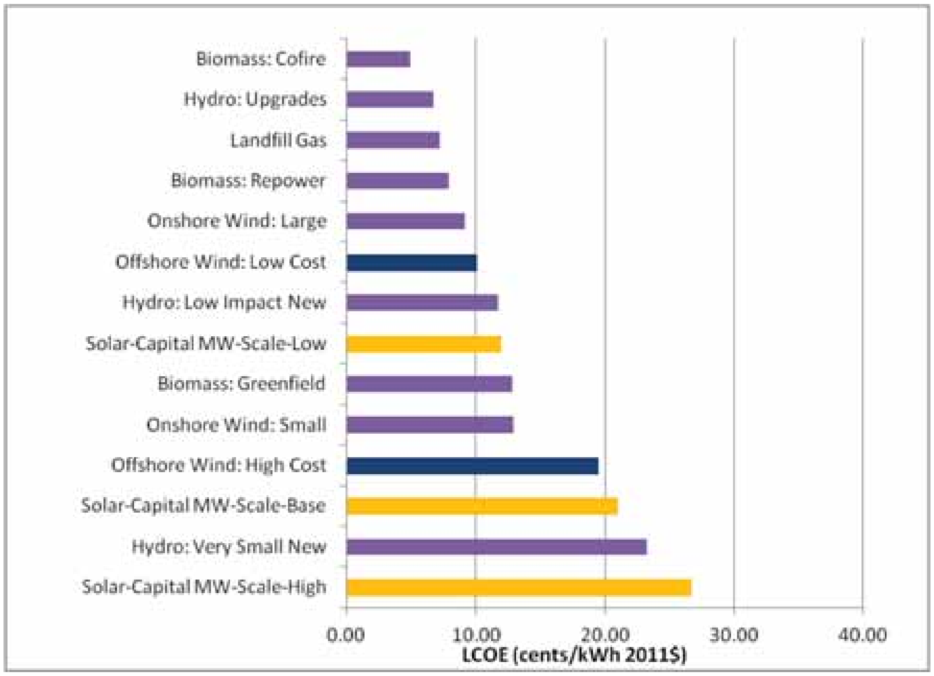

Figure 21. Levelized Cost of Energy, by Technology for 2025 (2011$)

In this comparison LCOE provides a useful, but not comprehensive, metric for comparing the merits of renewable energy technologies. While LCOE is an effective tool to compare generating technologies which may differ with respect to up-front and ongoing costs, it does not account for the market value of production differences between renewable energy technologies. For example, energy produced by a PV facility – which operates primarily during times of peak electricity consumption, and generates more during the summer than the winter – is likely to have a higher market value than wind energy – which, particularly in the northeast, generates a large portion of its output in the off-peak evening and night time hours, and generates more during the winter than the summer. PV's market value also derives from its ability locate within cities or other areas where energy prices are high and open space for electricity generating facilities is at a premium. Location on the distribution system can avoid transmission and distribution energy losses. Similarly, PV can often create its highest market value by locating behind-the-meter of a retail consumer and thereby avoiding not only generation but also transmission charges at time of coincident production and consumption.

Due to the differences between what is measured by LCOE and by market value of production, a full study of the costs and benefits of all renewable energy technologies would be required in order to facilitate the most meaningful comparisons and draw the deepest and most durable conclusions about the relative merits of PV compared to other renewable technologies.

A more detailed discussion of the methodology, inputs and LCOE results for each renewable energy technology is provided in Appendix 5.

4. PV DEPLOYMENT SCENARIOS

4.1. Introduction

This chapter describes several PV deployment scenarios – the physical characteristics and distribution of PV systems - that were developed for use in analyzing the impacts of alternative deployments of PV in New York. The chapter describes a reference scenario, which projects the impact of the current policy environment in New York. The chapter then describes three deployment scenarios which reach the PV deployment goals articulated in the Act. The three deployment scenarios employ different assumptions about the type and size of the PV systems installed sizes and their geographic distribution.

Key findings of this Chapter include:

- Existing PV policies and programs are expected to bring online approximately 420 MW of PV in New York State by 2025.
- In order to meet the targets of the Act, the majority of the new installations will need to occur between 2020 and 2025.
- New York State's PV policies to date have focused primarily on small-scale installations, but this historical system size distribution is not assumed to be indicative of future policy response.
- PV systems are expected to be developed in a number of installation sizes and types, including residential systems (up to 10 kW), small commercial systems (10-100 kW), large commercial (100-1000 kW) and megawatt-scale (> 1000 kW).
- For each of the different system types, the report assumed standard, representative system sizes based on distributions from New York and from neighboring markets: 4 kW (residential), 40 kW (small commercial), 400 kW (large commercial) and 2000 kW (megawatt-scale).
- PV systems may be installed either on the customer side or the grid side of a retail meter. For those systems on the customer side production can displace retail electricity purchases, either directly or financially. PV systems interconnected on the grid side of the retail meter will sell their production on the wholesale market, unless treated financially as part of a virtual net metering group. Most PV systems in New York are installed at a customer site, although neighboring states are seeing an increasing trend of MW-scale grid-connected system. The report assumes that the majority of systems will be installed on the customer side for each size category except for megawatt-scale. The majority of megawatt-scale systems are assumed to be installed on the grid side of the meter.
- The future geographic distribution of systems can be influenced by policy choices. The Base deployment scenario assumes that PV is distributed in proportion to electric load across the state.

Alternative deployment A (Alt-A) assumes a higher concentration of systems in New York City (with a higher percentage of smaller-scale systems), whereas alternative deployment B (Alt-B) assumes a higher concentration in rural areas in the rest of the state (with a higher percentage of megawatt-scale systems).

This chapter is organized as follows:

- Section 4.2 provides an overview of the deployment scenarios and reference case developed for this study.
- Section 4.3 describes the reference case and the Base Deployment used in the Base PV Scenario.
- Section 4.4 describes two alternative deployment scenarios used in the sensitivity analyses in later chapters of the study.
- A detailed description of the methodology for developing deployment scenarios and the underlying analysis and assumptions can be found in Appendix 9.

4.2. Deployment Scenarios

In response to policies designed to incentivize development of PV installation to meet the goals of the Act, private actors will deploy PV installations of various sizes in locations dispersed throughout New York State. The specific characteristics of such a response are referred to as a deployment scenario. Detailed deployment scenarios were developed to examine plausible futures for PV development in New York between the present and 2025. The characteristics used to define each deployment scenario consist of:

- The annual installed capacity target and trajectory, defined as the average direct current (DC) megawatts (MW_{DC}) of PV capacity installed in each year.
- The installation size distribution, characterized as the proportion of the annual installed capacity falling into a discrete number of 'standard' sizes.
- The financial compensation distribution, defined as the proportion of annual PV production for each standard installation size that is effectively consumed behind the retail meter (behind-the-meter or BTM), whose value to a host relates to avoided retail electricity expenses[62], versus that proportion delivered to the wholesale grid and earning wholesale electricity revenue (grid).
- The geographic distribution of PV development across different parts of New York.

62 Throughout this study, this concept is referred to at times as production that is *financially* consumed behind the retail meter, as such generation may earn its value to the host or owner through the displacement of retail electricity purchases. This concept is defined broadly to include both production consumed on-site by a host of a PV installation interconnected behind a retail meter, as well as any production treated as if consumed on-site under net metering or virtual net metering policies.

A reference case was developed to represent the expected PV deployment resulting from current solar policies and programs. In addition, three deployment scenarios were developed, representing differing installation size and geographic distributions. To reach the Act's target, it was assumed that the policies drive incremental PV solar capacity above the reference case. The combinations of distributions employed for each deployment scenario were selected to represent a range of anticipated detailed policy designs, as discussed further in Section A9.2.

4.3. Reference Case and Base PV Scenario Deployment

For the reference case, existing NYSERDA, LIPA and NYPA solar policies were projected until their sunset. The development of the reference case is described further in Appendix 9, Section A9.2. The Base Deployment Case, which is utilized in the Base PV Scenario throughout this report, meets the proposed targets established by the Act: 2,500 MW by 2020 and 5,000 MW by 2025. To reach these targets, it is assumed that the PV policy drives incremental PV solar capacity from the Reference Case up to the trend required to meet these targets (i.e. the difference between the annual target and the Reference Case is the increment driven by the PV policy).[63]

The installed capacity of the Base PV Scenario and the Reference Case are shown in Figure 22. The corresponding energy production, based on performance characteristics described in Chapter 3, is shown in Figure 23. The trajectory reflects the pace of stimulated PV development and drives the timing and magnitude of annual rate impact, employment impacts, costs, and benefits. As such, the trajectory is a central component of any PV policy design. Policymakers should therefore consider the actual temporal cost trajectory in establishing temporal policy targets, so as to craft a flexible and responsive policy. This would more likely create a predictable investment environment while not burdening ratepayers with the impacts of extreme price volatility.

63 For the years when the PV deployment overlaps with the existing RPS program (2013, 2014, and 2015) it was assumed that the solar generation displaces renewable energy generation that would have been procured as part of the existing RPS program.

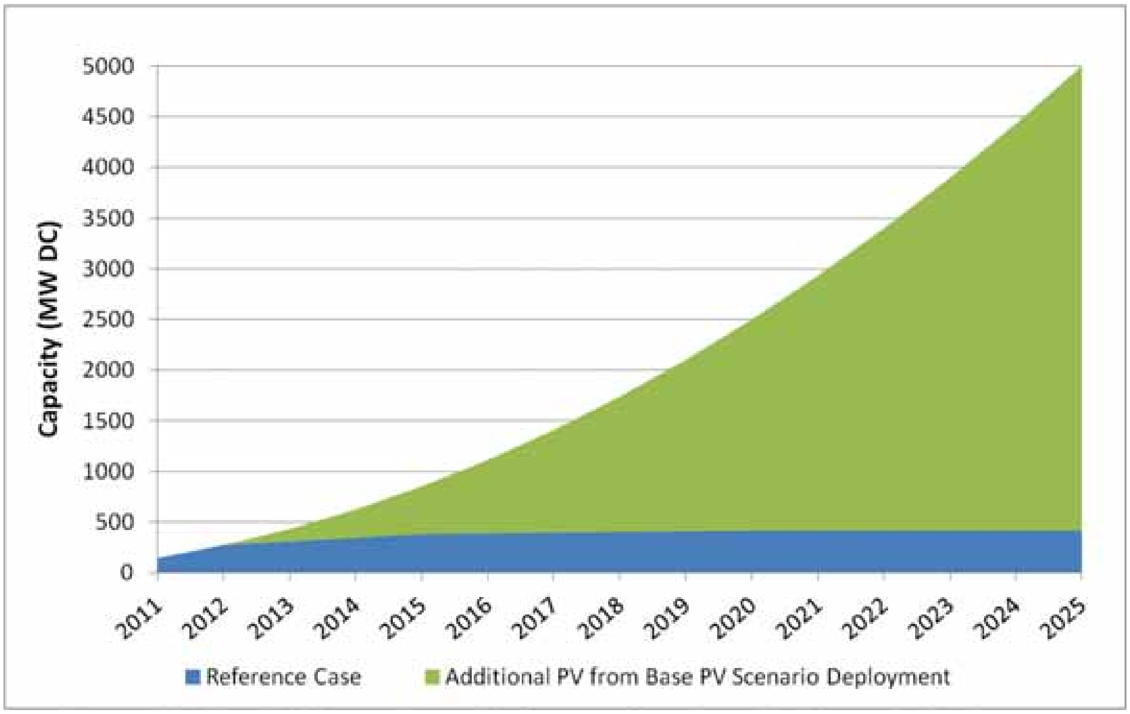

Figure 22. Base PV Scenario and Reference Case Installed Capacity Trajectory

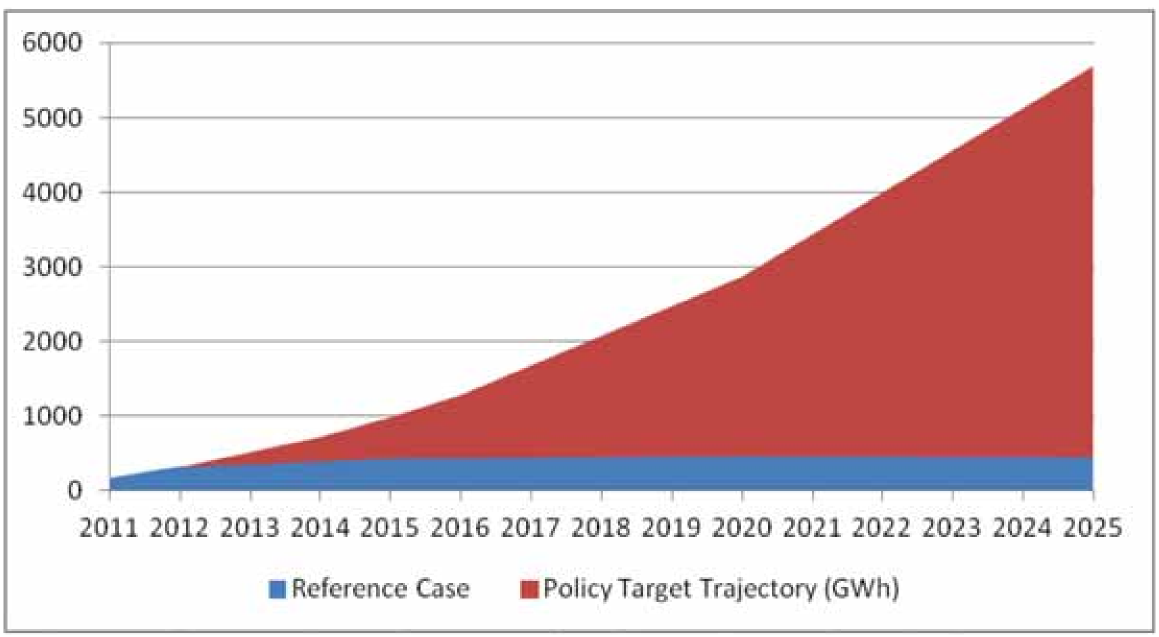

Figure 23. Projected Energy Production from PV Installations, Base PV Scenario and Reference Case (GWh/yr)

Scenario Assumptions were developed for each of the deployment scenarios modeled for total installed PV by system size class, geographic distribution and financial compensation distribution. Standard PV system sizes were defined for each of four classes of installations, with the corresponding size ranges of (i) residential (up to 10 kW), (ii) small commercial (10 – 100kW), (iii) large commercial (101 – 1000 kW), and (iv) megawatt-scale (exceeding 1000 kW). An average percentage across each class of production generation which earns its value based on displacement of retail electricity purchases (i.e. financially behind-the-meter) versus that portion sold to the grid (earning wholesale electricity revenue) was attributed to each installation size class. The distribution of systems used in the Base Deployment Scenario is shown in Table 26. The rationale for these assumptions is described in Appendix A, Section A9.5

Table 26. Base Deployment Scenario System Size Distribution

Class	Size Range	Average Size	% of Total in Each Year	% of Production Financially Behind-the-Meter	% of Production to Grid (Wholesale)
Residential Scale	0-10kW	4 kW	15%	100%	0%
C&I Host Scale - Small	10-100kW	40 kW	20%	90%	10%
C&I Host Scale - Large	100-1000kW	400 kW	45%	70%	30%
Megawatt Scale	1MW+	2000 kW	20%	15%	85%

The Base Deployment assumes PV systems are geographically distributed in a manner reflective of current load distribution patterns in New York. It therefore reflects a statewide policy consistent with an equal distribution of policy costs and benefits. It should be noted that this is not a least-cost distribution, as the costs of PV vary geographically (see Chapter 3), as does the market value of PV production (see Chapter 5). Installations within each of the eleven NYISO load zones were assigned to five aggregated geographic regions, shown in Figure 24. The resultant Base Deployment geographic distribution is summarized in Table 27. The rational for this distribution is further discussed in Appendix 9, Section A9.5.

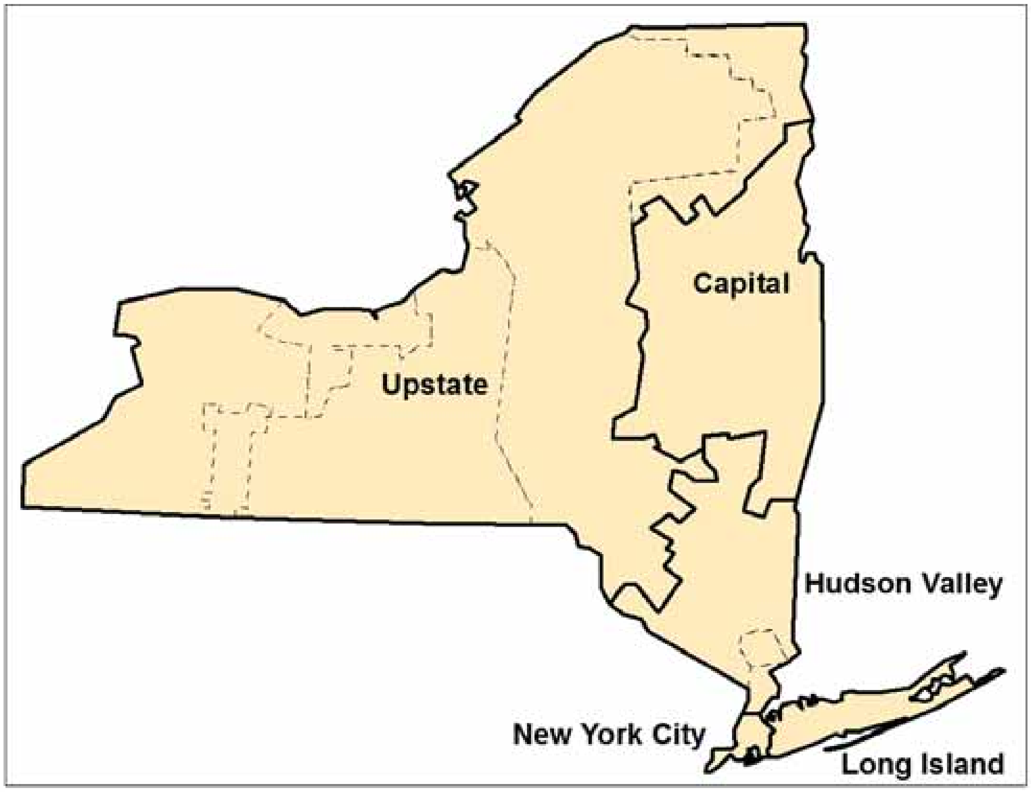

Figure 24. Aggregate Load Zones Used in this Analysis

Table 27. Base PV Deployment Geographic Distribution

BASE	UPSTATE	CAPITAL	HUDSON VALLEY	NY CITY	LONG ISLAND
Residential Scale	33.9%	6.5%	12.1%	33.6%	13.9%
C&I Host Scale - Small	33.9%	6.5%	12.1%	33.6%	13.9%
C&I Host Scale - Large	33.9%	6.5%	12.1%	33.6%	13.9%
Megawatt Scale	47.6%	9.1%	17.0%	6.7%	19.6%

4.4. PV Policy Deployment Alternative Scenario Projections

To test the sensitivity of the study's results to design choices that might favor installation distributions that are not proportional to the distribution of load across New York state, two alternative distributions were developed, referred to as *Alternative A* (*Alt-A*) and *Alternative B* (*Alt-B*). Alt-A represents a more urban- and distributed generation-focused deployment than found in the base case.

Alt-A is therefore comprised of a moderately greater proportion of small-scale and urban installations than the base deployment. The system size distribution for the Alt-A deployment scenario is the same as for the

Base deployment scenario, while the proportion of PV installations in NYC, Hudson Valley and Long Island regions was increased with a corresponding decrease in the Upstate and Capital regions.

Alt-B, on the other hand, is tilted more towards larger-scale systems capturing better scale-economies. Such a deployment would be expected to have a lower direct cost of installations, although due to variations in the value of the electricity produced, the relative cost and benefit compared to a Base Deployment requires additional analysis whose results are described in Chapter 5. The Alt-B distribution, due to the land-use patterns, implies a less urban, more rural distribution that the base deployment scenario. For the more rural Alt-B deployment scenario, the percentage of MW-scale PV installations was doubled over the base and urban cases. This substantial increase in the MW-scale class was offset by reductions in each of the other system size classes. Upstate and Capital region large commercial and MW-scale installations were increased relative to the Base deployment, while the same size classes were correspondingly reduced in NYC, Long Island and Hudson Valley regions.

Figure 25 shows the cumulative PV capacity in each geographic region, and by installation type, for each of the three deployment scenarios analyzed in this study. More detailed description of the deployment scenario derivation can be found in Appendix 9, Section A9.6. These deployments are used in the sensitivity analysis described in the remainder of this study.

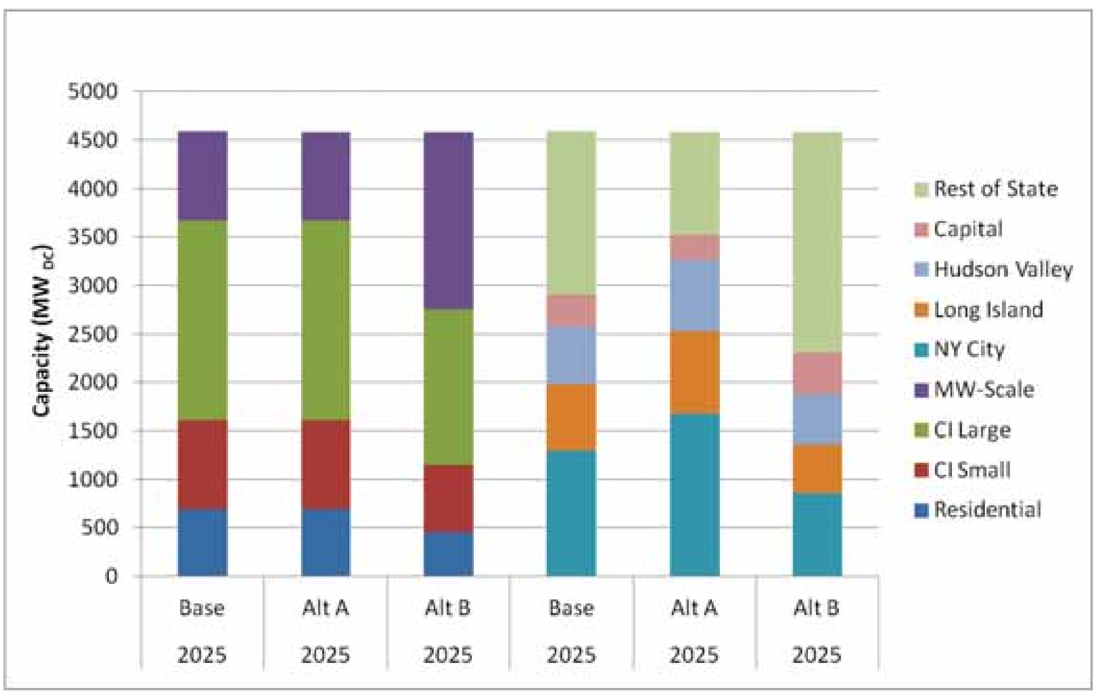

Figure 25. 2025 Size and Geographic Distribution of Additional PV under Base, Alt-A and Alt-B Deployment Scenarios

5. DIRECT COSTS AND BENEFITS

5.1. INTRODUCTION

This chapter describes the analysis of direct economic and carbon dioxide impacts of deploying PV systems in New York. It estimates and analyzes major cost and benefits of deploying solar under a range of electricity price futures and for different policy options.

Key findings of this Chapter include:

- The benefits of PV include price suppression in wholesale energy and capacity markets as relatively high marginal cost fossil fuel generating units are displaced by solar generation, market revenues from wholesale energy and capacity markets; avoided losses; avoided distribution costs and RPS compliance costs; and monetized carbon values.
- The primary costs include the actual costs of the policies in terms of revenues to solar facility owners to install, operate, and maintain the solar facilities.
- Wholesale price suppression revenue benefits account for over 80 % of total benefits. Due to the sudden decrease in price suppression impacts in 2030, most of these benefits are concentrated in the first 20 years.
- Avoided electricity production costs are also an important driver of benefits, while other factors, including reduction in carbon dioxide, reduction in the use of fossil fuels, avoided distribution system upgrades, and avoided line losses showed smaller benefits.
- Under the Base PV scenario, reaching the 5,000 MW target results in a net cost for New York of $2 billion.
- Net costs were highly sensitive to assumptions about PV cost. Under the low cost scenario reaching the goal had a net benefit of $2 billion, while under the high cost assumptions, the policy had a net cost of $8 billion.
- Increased deployment of PV downstate had a higher benefit-cost ratio, lowering the overall costs of meeting the Goals by nearly $1 billion, as electricity costs are higher in the New York City region.

This chapter is organized as follows:

- Section 5.2 focuses on the modeling of New York's wholesale electricity market to estimate the energy and capacity value of PV.
- Section 5.3 identifies and assesses the key costs and benefits of the Base PV policy such as the wholesale market value of PV generation, potential price suppression impact of additional PV on the

energy and capacity markets, carbon dioxide emissions reductions, avoided line losses and RPS program renewable energy attribute purchases, and the value of distribution investment that may be avoided or deferred as a result of deploying PV resources.

- Section 5.4 provides an analysis of the sensitivity of results for a generic "base" policy to a range of variables including high natural gas prices, high cost and low cost PV futures, continued operation of Indian Point; and policy choices including alternative PV deployment scenarios and reduced policy targets.

Table 28 summarizes the sensitivity analyses described in this chapter.

Table 28. Scenarios and Sensitivity Analyses Explored in this Chapter

Scenarios	Sensitivity Analyses
Reference Case Base PV Scenario* (for 5000 MW by 2025 Policy Target)	High PV Cost Future* Low PV Cost Future* Alternative Installation Deployment A Alternative Installation Deployment B High Energy Prices* Indian Point Continued Operation

5.2. WHOLESALE ELECTRIC MARKET MODELING

This section focuses on estimating the wholesale energy and capacity market value of electricity produced by PV resources, realized by system owners for:

- Production delivered to the grid, revenue from electric energy and capacity sales; and
- Electricity financially consumed on-site by a retail system host of a behind-the-meter system, as a component of the cost of retail electricity costs avoided. For systems owned by the host, the value is realized through avoided purchase of electricity at retail. On third-party owner sales under power purchase agreements to system hosts, sales revenues are typically tied to the value of avoided retail electricity purchases.[64]

5.2.1 Modeling Methodology

5.2.1.1. Production Cost Simulation Model: IPM

The Integrated Planning Model ("IPM"), a production cost model maintained by ICF International, was used to simulate the operation of the New York electrical system and energy market. IPM takes as inputs the forecasted load levels in New York, generating units and each unit's operating characteristics, fuel

64 In Chapter 7, the additional components of avoided retail electricity purchases are calculated.

prices, and a representation of the transmission constraints. Using this information, IPM calculates the least-cost way to operate the generating units in order to serve load while observing the assumed transmission constraints and air pollution regulations.

5.2.1.2. IPM Reference Cases

Three reference cases were developed and run in IPM to support the modeling performed in this chapter:

- **Reference Case**. The primary reference case was a business-as-usual scenario reflecting expectations in the absence of the contemplated PV incentive policies. ICF developed various wholesale market inputs. These inputs are primary drivers of the wholesale market output and include data for the following variables:
    - Regional load forecast
    - Existing generation amount, type, and characteristics
    - Generation retirements for the reference case
    - Generation additions, including renewable generation added pursuant to New York's RPS program
    - Fuel prices
    - Transmission topology representation

  The selection of these inputs is consistent with other IPM work conducted for NYSERDA and recently for RGGI-related work and is not discussed here.[65]

- **Reference Case – Indian Point**. This reference case is used for testing the sensitivity of solar incentive policy costs and benefits to the continued operation of the Indian Point nuclear plant.
- **Reference Case – High Energy Prices**. This reference case allows for testing the sensitivity of solar incentive policy costs and benefits in a future with higher natural gas prices than assumed in the Reference Case.[66]

IPM modeling is extremely data intensive, and as a result, IPM modeling was performed for only the following years: 2011, 2012, 2014, 2015, 2016, 2020, 2025, 2030, and 2035.

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65 A discussion of the modeling assumptions and the IPM model can be found at: http://www.rggi.org/docs/RGGI_Reference_Case_Assumptions_091211.pdf

66 Natural gas prices were assumed to be 35% higher on average than the reference business-as-usual case, with annual differences ranging from 23-43% higher. The Henry Hub gas price trajectory was taken from the "Oil and Gas: Low Shale EUR" scenario from EIA (2011).

5.2.1.3. Time Horizon

The time horizon of the study is 2013-2049. This period represents the policy incentive period spanning 2013 (the first year in which installations are assumed under new solar policy) though 2025, the year of the Act's 5000 MW target. As a 25 year economic life is assumed for PV installations, systems installed in the last year of policy incentives are assumed to produce through 2049. Determining the rate impact of policies providing incentives over a PV system's economic life (those other than up-front rebates) requires estimating the PV premiums through 2049. As IPM outputs are not produced for each year of the study period, IPM outputs were interpolated and extrapolated for the remaining years of the study period.

5.2.1.4. PV Cases: Deployments, Quantities & Production Profiles

In total, three different deployments were utilized—Base deployment, Alt-A deployment, and Alt-B deployment—and for which IPM outputs were produced[67]. For the years when the PV deployment overlaps with the existing RPS program (2013, 2014, and 2015) it was assumed that the solar generation displaces renewable energy generation that would have been procured as part of the existing RPS program. Given the prescribed PV deployment, the IPM model selected which renewable resources would most economically meet the RPS program requirement (it did not select additional PV given the high cost). Therefore some of the policy cost of installing PV is off-set by a reduced requirement to purchase renewable attributes as part of the existing RPS program. Nevertheless, given the higher cost of PV relative to the other renewable technologies (e.g. wind, biomass, and small hydropower) the additional PV generation requirement would raise the total cost of achieving the RPS program goal.

Study inputs to IPM included the solar deployment quantities, timing and regional-level locations as discussed in Chapter 4, the breakdown of proportion of capacity whose energy is consumed either behind-the-meter or delivered to the grid, and the temporal production profile of the solar installations. Each of these factors plays a part in projecting PV resource revenues based on the NYISO energy and capacity market.

Production profiles were created using NREL's PV Watts solar calculator[68] for each region and project size combination specified in Section 3.7. Assumptions for orientation and tilt matched those used in deriving projected LCOEs. The production profile is held constant throughout the study period. Separate production profiles were developed for the four standard PV installation types and sizes—Residential, Small C&I, Large C&I, and MW-scale - and for three different regions—Upstate, Capital, and a consolidated region encompassing the NYC, Downstate, and Long Island regions described in Chapter 4. In total, twelve different production profiles were used as input to IPM. To illustrate the characteristics of production

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67 As previously described: the Base deployment is reflective of load distribution patterns in the state; Alt-A is a more urban and small-scale distributed generation-focused deployment; Alt-B is a more rural, larger-scale-focused deployment.

68 This model is described in Chapter 3.

profiles, Figure 26 shows the daily production profiles that were used for residential installations located in the NYC, Downstate, and Long Island regions for four different seasons.

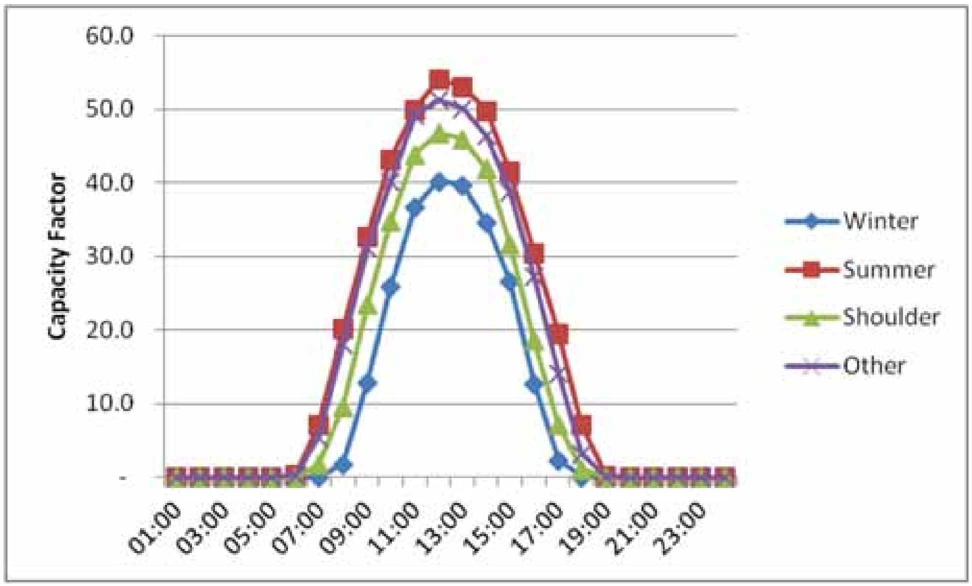

Figure 26. Residential Production Profile, NYC, Downstate, and LI Regions

To account for the assumed panel degradation of 0.5% per year, the capacity of PV included in the IPM model was reduced, so that the energy produced each year is consistent with the calculation of expected energy production from annually degrading panels as used in developing LCOE projections in Chapter 4.[69]

5.2.1.5. Impact of PV on Planning and Operating Reserves

The impact of incremental PV quantities on regulation, operating reserve, and other ancillary service requirements and markets were not calculated. IPM is a planning optimization model whose inputs are most effective at estimating planning reserve impacts. It was assumed that an increase in the amount of intermittent resources on the system would not affect the overall planning reserve requirement. However, the types of resources that are built to meet the planning reserve requirement may be affected by the presence of large quantities of incremental PV capacity. IPM adjusts the types of resources that are built to meet the planning reserve requirement to reflect the anticipated capacity credit of the modeled PV.

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69 A total of 4,480 MW would be added under the base full target solar deployment scenario. This 4,480 is the total number of installed MW adjusted to reflect 0.5% annual degradation on a capacity basis, which corresponds to annual energy production from approximately 4,585 MW of nameplate installed capacity with the same degradation rate applied to energy production. Adding this amount of solar installs plus the 415 MW that is included in the IPM reference case (with existing solar policies) results in a total of 5,000 MW nameplate capacity of PV resources that were modeled in IPM in 2025 through 2037 and affect the New York capacity balance. The 5,000 MW total begins to decrease in 2038 as investments installed in 2013, the first year of the solar policy, reach the end of their useful life, which was assumed to be 25 years.

In addition to the planning reserve requirement there might also be a need for more flexible generation sources units to account for the operating reserve requirements that could change slightly with a large infusion of widely distributed intermittent resources. IPM does not have the ability to address operating reserve requirements and how these might change.

5.2.1.6. Modeling Behind-the-Meter Generation

Modeling behind-the-meter resources involved explicitly representing them in the IPM market model, appropriately adjusted for the effect of losses, as opposed to netting their production from load. The benefits of this method include easier and more exact identification of the energy and capacity value contributed by the resource and a more direct comparison of the price suppression impacts of the modeled resources.

5.2.2 Key Outputs and Inputs

The key IPM outputs included annual output from incremental PV resources by region, the annual capacity and energy market value of production[70] for the PV resources, and the capacity value of the PV resources. Five key sets of outputs from the IPM modeling results and one key input that was used by the model summarize the salient wholesale markets modeling results:

- Annual output of incremental PV resources (calculated as an output based on capacity value and deployment inputs)
- Capacity value of incremental PV resources (input)
- Annual energy market revenues of incremental PV resources
- Annual capacity market revenues of incremental PV resources
- Wholesale Firm Electricity Value (\$/MWh)[71]

Table 29, Table 30 and Table 31 show these results on a statewide basis for each of the three deployments references above, for the IPM run years in the study period. These results are generated by comparing two cases—the reference case with existing solar policies (and no additional solar deployments) and the indicated PV deployment case.

70 The cost and revenue figures produced by IPM in real (2010) dollars were converted to nominal dollars for comparison and comparability with LCOE projections derived in nominal dollars.

71 Wholesale firm electricity value is an output developed by ICF that combines the production-weighted energy and capacity values into a single dollar per MWh metric.

Table 29. Statewide IPM Inputs and Outputs, Base PV Scenario Compared to Reference Case

	Additional Cumulative Annual PV Energy Output (MWH)	Additional Installed PV (MW)	Additional Cumulative PV Capacity Value (MW)	Annual Energy Market Revenues (Nominal $)	Annual Capacity Market Revenues (Nominal $)	Wholesale Firm Energy Price (Nominal $)
2014	327,122	280	104	18,458,760	4,472,091	65.77
2015	549,117	470	174	34,625,764	7,793,398	71.37
2016	842,281	721	267	52,037,616	6,701,891	66.60
2020	2,402,877	2,057	761	176,270,979	95,640,386	102.60
2025	5,233,789	4,480	1,658	499,315,998	240,598,141	128.83
2030	5,233,789	4,480	1,658	539,253,708	289,324,052	146.92
2035	5,233,789	4,480	1,658	626,496,359	286,297,147	162.91

Table 30. Statewide IPM Inputs and Outputs, Alt-A Deployment

Compared to Reference Case

	Additional Cumulative Annual Solar Energy Output (MWH)	Additional Installed PV (MW)	Additional Cumulative PV Capacity Value (MW)	Annual Energy Market Revenues (Nominal $)	Annual Capacity Market Revenues (Nominal $)	Wholesale Firm Energy Price (Nominal $)
2014	329,236	279	103	18,893,016	4,921,812	65.69
2015	551,095	467	173	35,980,174	8,342,710	71.18
2016	850,685	721	267	53,773,400	6,479,364	65.98
2020	2,425,838	2,056	761	179,383,053	102,020,086	101.90
2025	5,284,779	4,479	1,657	517,732,664	252,571,179	128.17
2030	5,284,779	4,479	1,657	551,744,612	317,905,800	146.76
2035	5,284,779	4,479	1,657	640,850,993	310,287,704	162.59

Table 31. Statewide IPM Inputs and Outputs, Alt-B Deployment Compared to Reference Case

	Additional Cumulative Annual PV Energy Output (MWH)	Additional Installed PV (MW)	Additional Cumulative PV Capacity Value (MW)	Annual Energy Market Revenues (Nominal $)	Annual Capacity Market Revenues (Nominal $)	Wholesale Firm Energy Price (Nominal $)
2014	326,315	278	103	18,066,427	3,855,306	65.80
2015	548,246	467	173	33,160,771	6,887,679	71.53
2016	847,342	722	267	51,071,330	6,086,253	66.80
2020	2,414,335	2,057	761	177,012,480	88,320,372	104.64
2025	5,255,834	4,478	1,657	484,475,225	239,281,069	131.30
2030	5,255,834	4,478	1,657	531,571,364	256,865,076	147.10
2035	5,255,834	4,478	1,657	619,469,116	248,193,414	162.22

The capacity values shown above represent 0.37 of the total nameplate MW deployed. Thus, by 2025, which is the full deployment year, there are 4,480 MW[72] added (and input) to IPM in addition to the amounts assumed to be in the business-as-usual reference case. For intermittent resources, NYISO has a process for determining the amount of capacity credit, relative to installed capacity, that is the basis for offering into and clearing out of the NY wholesale capacity market. Per NYISO, "Unforced Capacity from an Intermittent Power Resource for the summer capability period shall be based on the average production during the 14:00 to 18:00 hours for the months of June, July and August during the Prior Equivalent Capability Period." While the actual value would fluctuate from year to year, an average credit of 37% was presumed for all PV deployments in this study. This number is in line with the production profiles used in this study as well as NYISO reported percentages (NYISO, 2011). For example, Figure 26 shows a 35% capacity factor for those hours.

[72] Calculated as (1/Assumed capacity factor of 0.37 x 1658 MW).

Use of the production profiles discussed above did capture PV's contribution during peak periods. Figure 27 compares the statewide wholesale firm energy prices shown in Table 29 to the realized firm energy prices "received" by solar projects. The figure shows that solar production occurs during higher-than-average priced hours, resulting in greater (11% higher in the 2020-2025 period) realized firm energy prices.[73]

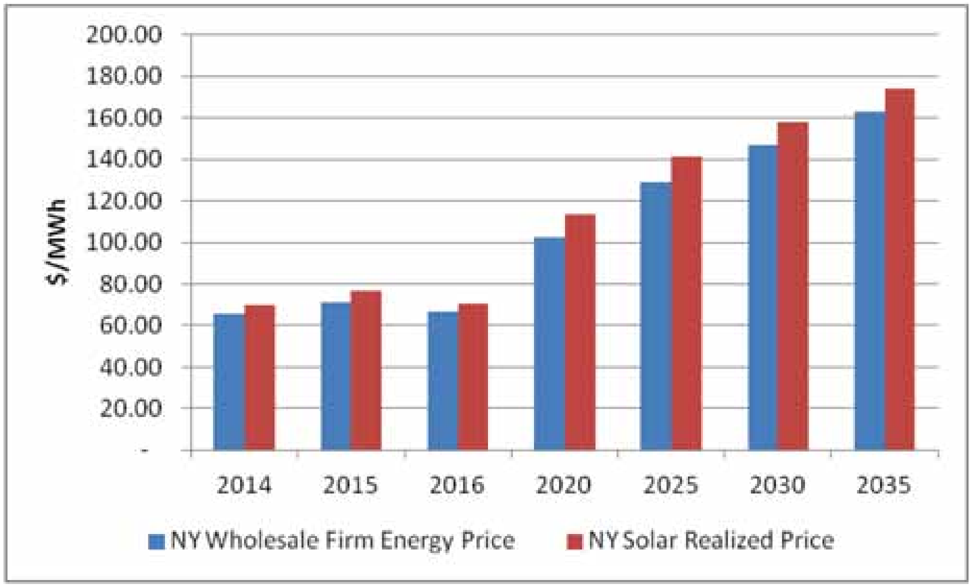

Figure 27. Wholesale Firm Energy vs. PV Realized Prices, Base PV Scenario

Figure 28 and Figure 29 respectively, show the energy output and capacity value of the four deployment scenarios that were used in the IPM runs. Four IPM model run years were shown. The figures show almost identical information for year 2025 and 2035 because all solar installs are still operational through 2038. After that time, both energy and capacity fall as units reach the end of their useful lives.

73 Realized prices for PV located in New York City are 13% higher during the same period.

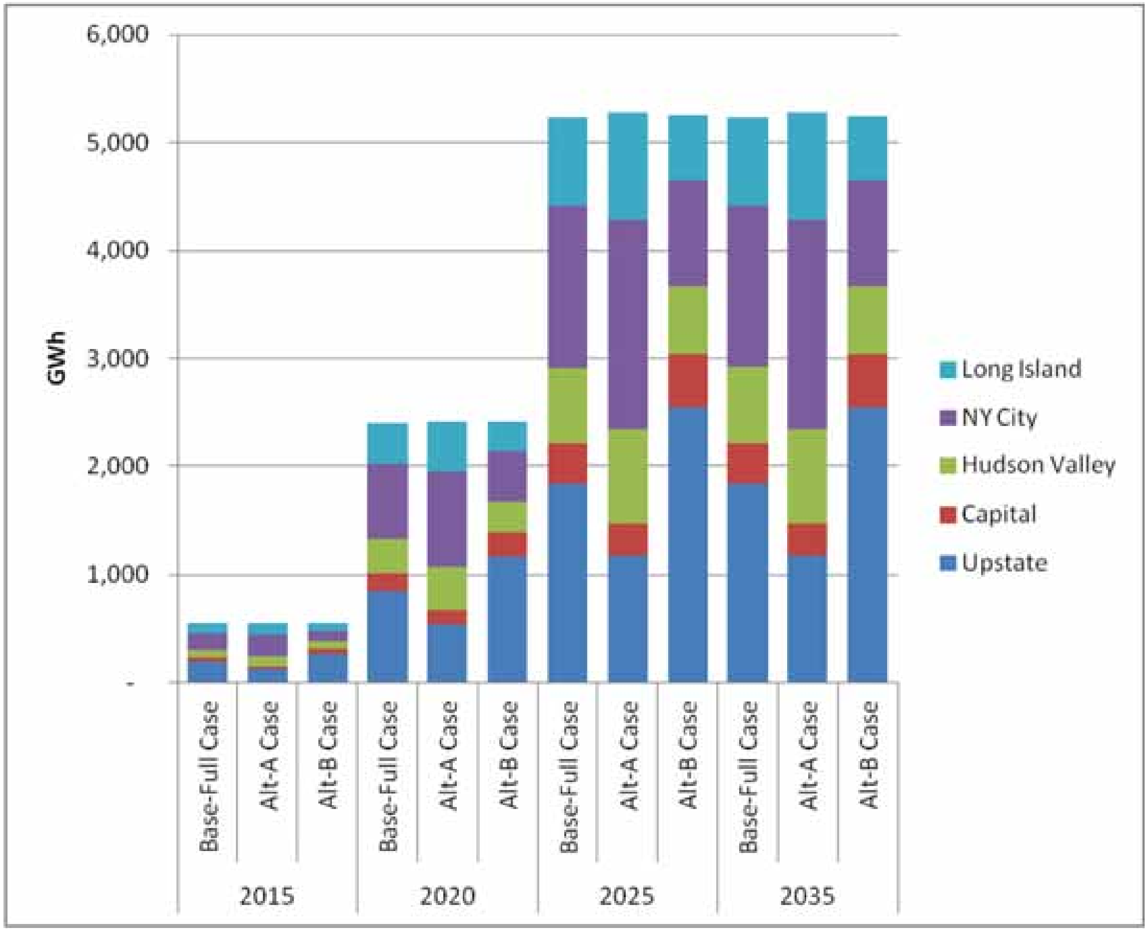

Figure 28. PV Energy Output of Deployment Scenarios Compared to Relevant Reference Cases, 2015, 2020, 2025, 2035

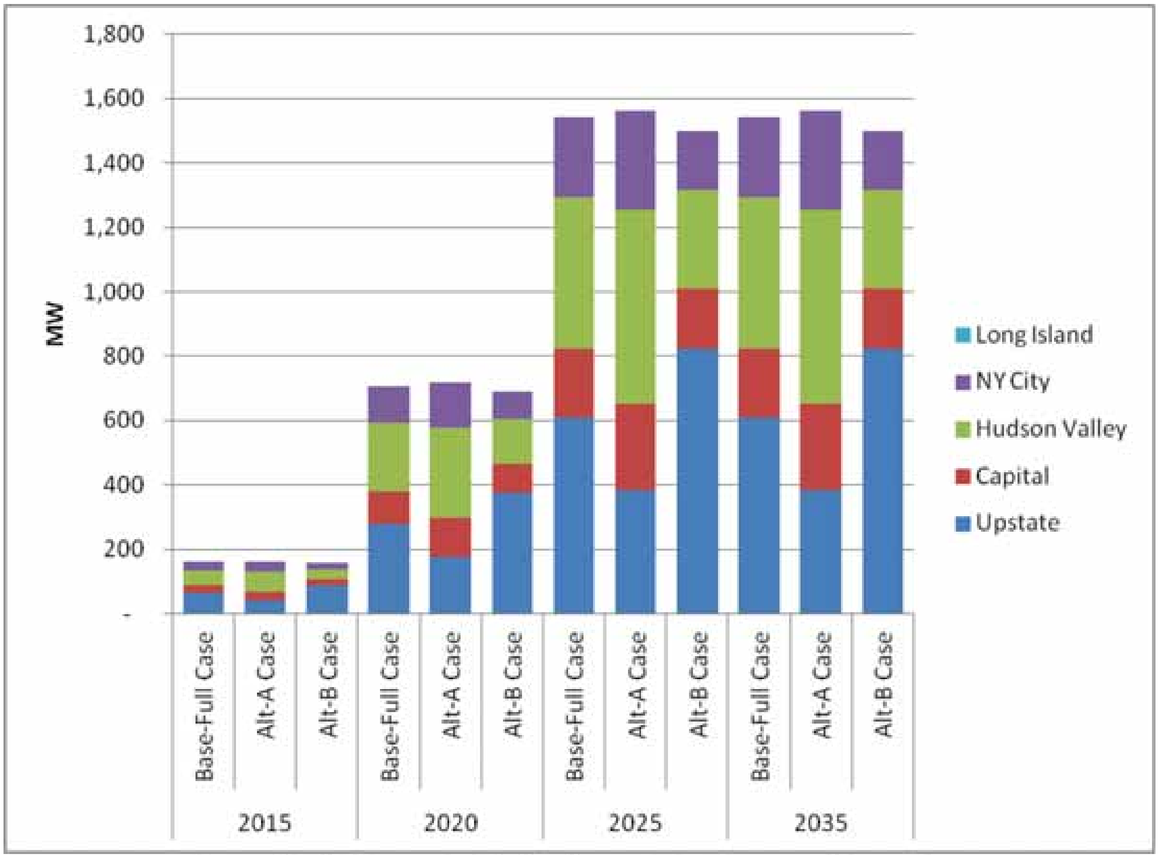

Figure 29. PV Capacity Value for each Deployment Scenarios Compared to Relevant Reference Cases, 2015, 2020, 2025, 2035

In addition to modeling wholesale market impact of the deployments mentioned above, two sensitivity analyses were performed in IPM on the Base deployment: (1) a high natural gas price future, and (2) a future assuming Indian Point remains an active nuclear facility. The results of these sensitivities are summarized in Section 5.4 for these along with other sensitivity analyses.

5.3. Costs & Benefits

This framework focuses on cost and benefits to New York consumers. In this section we discuss a number of additional benefits including price suppression impacts[74], environmental benefits through displaced fossil fuel, avoided distribution investment, and avoided RPS compliance costs that were not included in

74 Price suppression is a benefit from the perspective of New York's ratepayers. It is generally considered a transfer payment from generators (some of whom are out-of-state entities) to ratepayers. See (Felder, 2011).

the rate impacts above.[75] For reasons described above, benefits do not vary across the different policy options, but each policy option has a unique cost profile. These benefit categories are discussed in turn.

Table 32 shows the cost and benefit components that were used in the overall cost/benefit analysis.

Table 32. Cost and Benefit Components

Costs	**Benefits**[76]
Cost of Solar PV	Wholesale Energy Market Value
Administrative Costs	Wholesale Capacity Market Value
	Avoided Losses
	Price Suppression
	Avoided Distribution Costs
	Avoided RPS Compliance Costs
	Monetized Carbon Values

It is important to note that economic development impacts, which are discussed in the next chapter, and retail market values were not captured in the cost benefit analysis. In addition to wholesale market values (and related price suppression in those markets), avoided losses are included because solar installations are assumed to be located behind-the-meter or close to load and thus used to supply local load.   For delivery charges, it is reasonable to assume for cost benefit analysis purposes that the transfer of distribution and transmission costs (e.g. due to net metering policies) to other ratepayers would not be treated as a benefit. In contrast, the avoided distribution costs value above refers to costs due to avoided or deferred investments in the distribution system due to solar installations. Still, there may be retail supply charges (ancillary services, ISO related costs, load balancing costs, and retail supplier fees and markups) that are not included in wholesale energy and capacity market values. Moreover, there are a number of quantifiable benefits, such as mitigation of generation fuel cost variability and grid security enhancements, that were beyond the scope of the current study and were not included in the overall calculations of net benefit (or cost).   As a result, the cost-benefit estimates shown in this section and in the next chapter may understate the benefit and that net benefits would be higher (or net costs lower) if these retail supply charge components were included.

Table 33 and Figure 30 show the calculations of each of these components on an NPV basis (in $2011) using a nominal 7% discount rate. The NPV of net cost ($2,183 million) of the base PV policy is also shown in the figure.

75 Benefits including avoided line losses and the market value of PV production are embedded in figures shown below, as are administrative costs associated with each policy (where applicable).

76 This study does not consider other potential, but uncertain and difficult to quantify, benefits which have been studied elsewhere, including PV's potential to mitigate or hedge ratepayer exposure to fuel cost variability (Bolinger, Grace, Smith, & Wiser, 2003), and PV's ability to enhance grid security (Perez, Zweibel, & Hoff, 2011) .

Table 33. NPV of Cost and Benefit Components, Base Policy

Cost-Benefit Component	NPV (2011$)
Cost of Solar PV	$11,779
Market Revenues	($4,611)
Avoided Losses	($332)
Price Suppression	($3,282)
Avoided Distribution	($811)
Avoided RPS Compliance Costs	($106)
Avoided Carbon	($455)

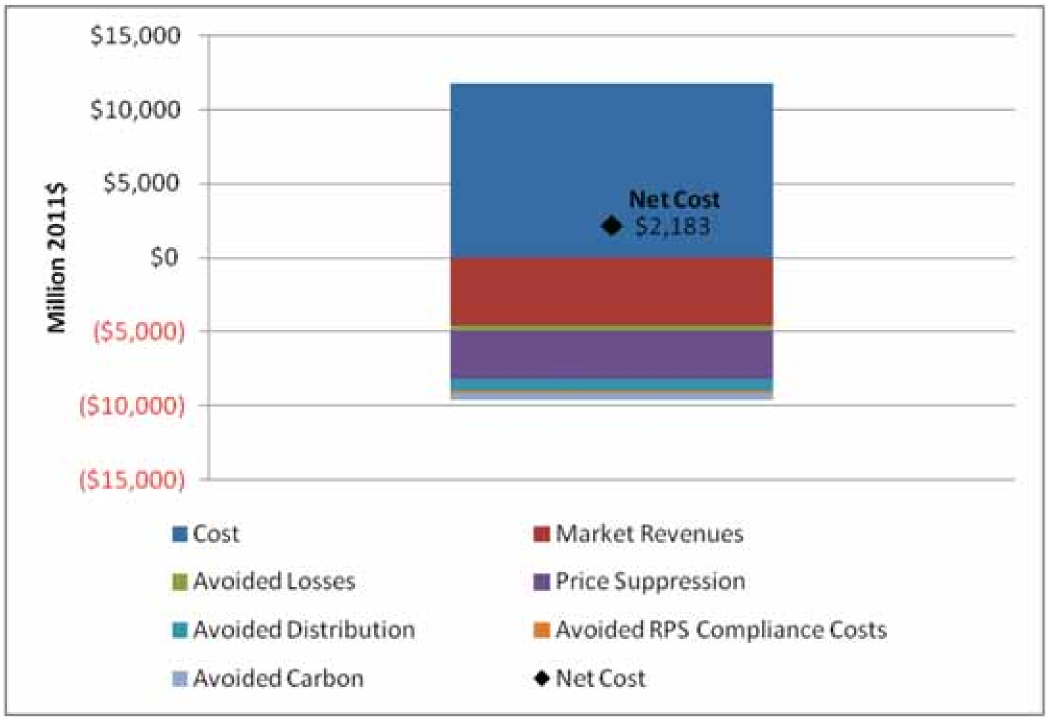

Figure 30. NPV of Cost and Benefit Components, Base Policy

5.3.1 Air Emissions

The IPM model was used to project the total amount of air emissions avoided from the deployment of PV resources across the state, as further discussed in Chapter 8. Air emissions tracked in IPM include NO_x, SO_2, mercury and CO_2.

Utilizing the IPM model allows the effects on emissions to be evaluated on a marginal basis. This is the ideal method as it identifies the specific marginal resources that are affected by the deployment of PV across New York and calculates the impact to their emissions. In IPM, the RGGI program is modeled as a hard emission cap with allowance trading. IPM solves for the allowance price needed to meet the cap, but with a floor price equal to the floor price specified for the RGGI auction. The allowance price flows through the market solution to outputs such as energy prices and investment decisions.

The impact on emissions is calculated by comparing the total emissions from New York resources in the relevant reference case to total emissions from New York resources in each of the deployment scenarios modeled (and under different sensitivity cases, discussed below). In this chapter we only examine the impact of monetizing carbon emissions from the Base deployment. Additional detail concerning environmental impacts is found in Chapter 8.

For the cost and benefit analysis, a value of $15/ton value was applied in 2010$.[77]

5.3.2 Price Suppression

Wholesale price suppression (in both energy and capacity markets) is considered to be a benefit to consumers, to the extent that this impact represents a transfer effect from producers to consumers. For this analysis, the price suppression benefits of deploying PV were calculated relative to the reference case. The price suppression benefits are calculated as the difference between the reference case (business as usual) wholesale firm electricity prices (discussed above) and the prices that reflect the impact of the relevant PV deployment (and other modeling assumptions, which are systematically modified in various sensitivity analyses). The price differences on a per unit basis ($/MWh) are then multiplied by total load levels (from the business as usual case) to estimate the total dollar value saved by consumers due to the presence of the PV resources.

It was assumed that savings to consumers due to price suppression applies to all load. However, particularly in the very near term, there may not be complete transference of estimated wholesale price suppression benefits to consumers. For example, there are legacy long-term contracts for load entered into prior to the solar policy and production used for self-supply by resources owned or controlled by load-serving entities that would not be impacted by the solar policy. While the load-serving entities that are responsible for most of New York's load have divested their generation assets and regularly procure energy to serve their load through frequent short term market solicitations, assuming that customer savings applies to all load may overstate the price suppression benefits due to existing terms of long-term contracts.

77 The base value has been used and approved by the NY DPS.

5.3.3 Avoided Distribution Benefits

The value of distribution investment that is avoided or deferred as a result of deploying PV resources across New York State was examined through a review of the existing literature as well as a review of DPS standard practice. Based on this evaluation, the values for the long run avoided cost of distribution investment were assumed to be $33.48/kW-yr for upstate New York and $100/kW-yr for New York City.[78] These values were multiplied by the derated capacity values of PV (shown above) to calculate avoided distribution investment.

5.3.4 Avoided RPS Compliance Costs

Avoided RPS compliance costs resulting from avoided RPS Attribute payments were calculated using outputs from the IPM analysis. Different solar deployments due to solar policies lead to displacement of renewable generation to be procured under the New York RPS discussed in Section 2.3. In effect, solar RECs are substituted for RPS Attributes produced by NYSERDA from wind and biomass facilities, resulting in a benefit stream that should be included in the overall cost-benefit analysis.[79]

5.3.5 Overall Cost Benefit Analysis

Figure 31 shows the value of each of the components in the cost benefit analysis (under the generic Base policy (with admin costs) and PV cost assumptions) for the entire study period. The black line represents the net cost on an annual basis.

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78 Appendix 2 in the January 16, 2009 NY PSC Order in docket 08-E-1003

79 The reference case IPM scenario includes the cost of meeting New York's RPS. In effect, the Solar PV policy is analyzed as contributing to meeting the RPS targets, or substituting for RPS procurement, so that solar PV additions reduce the need to procure RPS Attributes for the New York RPS. Avoided RPS Compliance costs are assumed to end in 2025 at the conclusion of the long-term contracts entered into under the RPS program.

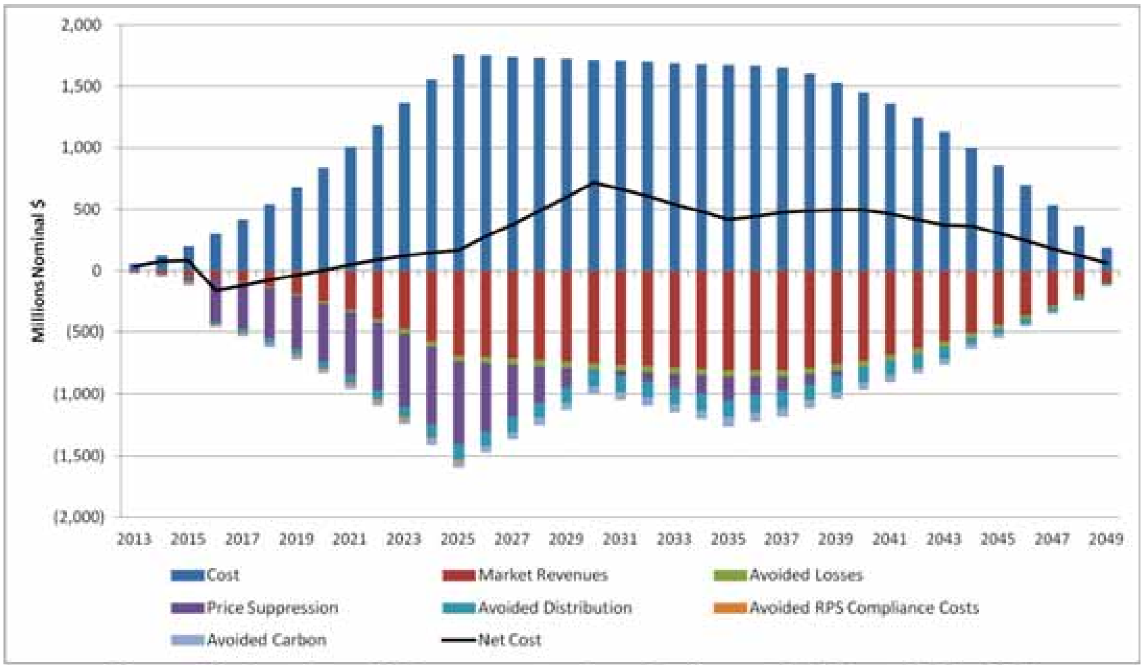

Figure 31. Cost Benefit Components, Base Policy and PV Cost, 2013-2049

Figure 31 shows that, except for a few years at the beginning of the study period (2016-2019), costs exceed benefits for almost all years under base cost conditions. Though the base policy does not include administrative costs, they are included here to show their relative importance (or lack thereof) compared to other cost-benefit components.

5.4. Sensitivity Analyses

Analyses of the sensitivity of results to key variables were conducted. The first sensitivity analysis examines how the future cost of installed PV impacts the cost of the base policy. It is expected that changes in cost futures will have the largest impact given the results shown in Figure 31 above. An analysis of alternative deployment scenarios (Alt A and Alt B) follows. Two sensitivities that directly affect the wholesale modeling--high energy prices (modeled as high natural gas prices relative to the reference case[80]) and continued operation of Indian Point Station—were also included.

80 Natural gas prices average 35% higher over the study period for the high natural gas sensitivity case compared to the reference case and range from 23-43% higher depending on the particular year.

All graphs compare the net costs (or benefits) of the base policy to the different sensitivity cases. All net cost data assume base carbon values. Table 34 summarizes the NPV values for the base policy and all the sensitivities.[81]

Table 34. NPV of Net Cost (Benefit), Base PV Policy Compared to Sensitivity Cases, 2011$

NPV	Million 2011$
Base PV Policy	$2,200
Low PV Cost	($2,100)
High PV Cost	$7,600
Alt A	$1,200
Alt B	$3,700
High NG	$1,100
IP	$2,200

5.4.1 Sensitivity Analyses: Cost of PV

Figure 32 shows the net cost/benefit under base, low, and high PV capital costs. Not surprisingly, the overall results are most sensitive to the cost trajectory of PV installations. IPM modeling results are assumed to be identical for all three cost cases.

Figure 32 shows a peak net cost in 2030[82] mostly due to the fact that price suppression impacts are significantly lower (see Figure 31) after that year.

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81 NPV calculations in this chapter use a nominal 7.0% discount rate (which corresponds to a real discount rate of 5.1%). In the appendix to this chapter, NPVs are also shown using a lower discount rate of 4.35% and a higher discount rate of 12%.

82 The IPM modeling results show price suppression converging for all cases and diminishing significantly in 2030. Hence, 2030 is shown as the highest net cost year across all the sensitivities.

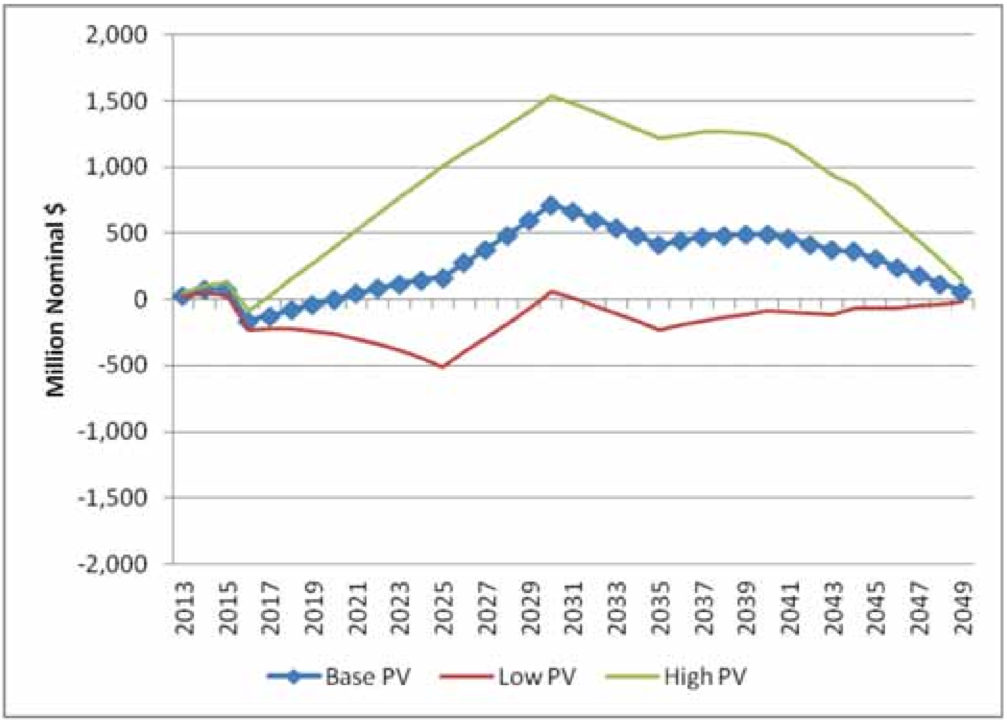

Figure 32. Net Costs/Benefit, Base, Low and High PV Cost, Using Base Carbon Value 2013-2049

Table 35 shows that net cost/benefit are highly sensitive to the assumed capital cost trajectory. Wholesale price suppression impacts did not change since solar facility sponsors are assumed to be price takers—that is, the price of PV does not impact wholesale markets (i.e., it is not used to determine wholesale market bids and thus wholesale market prices).

Table 35. Wholesale Price Suppression and Net Cost/Benefit, Base Policy vs. High and Low PV Cost, 2013-2049, $2011NPV

Million 2011$	Base	High Cost	Low Cost
Wholesale Price Suppression	(3,300)	(3,300)	(3,300)
Net Cost/Benefit (positive = cost) (negative = benefit)	2,200	7,600	(2,100)

5.4.2 Sensitivity Analyses: Alternative Deployment Scenarios

Figure 33 examines the sensitivity of net cost results to alternative deployment scenarios. Net costs are highest for the Alt-B deployment. As discussed in Chapter 4, the Alt-B deployment features more rural, larger scale deployments. The net costs results show divergent results in the initial years but converge in 2030 as wholesale market revenues increase. This divergence in the initial years is largely due to larger price suppression impacts for the Alt-A and Base deployments shown in the wholesale modeling results. In addition, though the Alt-B deployments feature lower cost installations (larger, rural), wholesale market revenues are also lower in these locations hence the benefit of lower cost installations is somewhat mitigated.

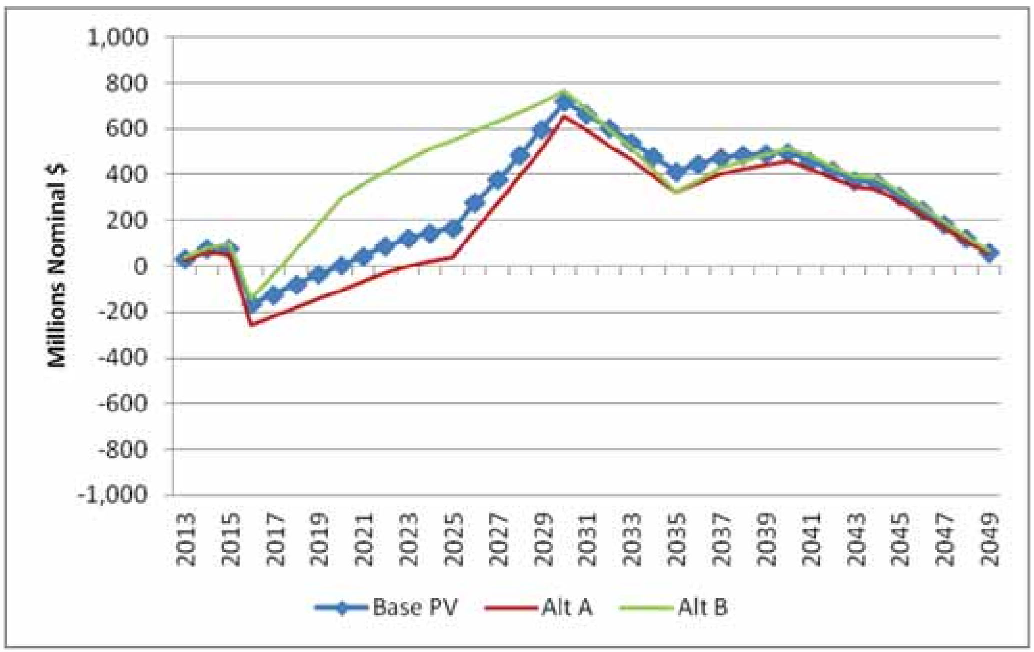

Figure 33. Net Costs/Benefit: Base, Alt-A, and Alt-B, using Base Carbon Value, 2013-2049

Price suppression is highest for the Alt-A Deployment due to its greater deployment of smaller solar installations in urban areas, which tend to be more congested and feature higher electricity prices. Moreover, Table 36 shows the marked reduction in price suppression impacts after 2030 for all three deployment cases. The greater price suppression benefits associated with the Alt-A deployment lead to a lower net cost than the base policy and Alt-B deployments.

Table 36. Wholesale Price Suppression and Net Costs, Base Policy vs. Alt-A and Alt-B Deployment 2013-2049, NPV 2011$

Million 2011$	Base	Alt A	Alt B
Wholesale Price Suppression	(3,300)	(4,000)	(1,800)
Net Cost Impact)	2,200	1,200	3,700

5.4.3 Sensitivity Analysis: High Energy Prices

Figure 34 shows the sensitivity analysis under high natural gas prices. Higher energy prices should, holding other things constant, increase potential market revenues to solar projects and increase price suppression impacts. This impact remains relatively constant through the 2038 year, which is the last year of the useful life of the first solar deployment (in 2013). As solar facilities "retire", the impact of higher natural gas prices is mitigated and eventually come close to disappearing in the final year of the study period.

Overall, the net cost data show a similar impact and pattern from higher natural gas prices, but net costs are actually higher in the first few years of the deployment schedule as the limited deployment during these years are not high enough to generate meaningful price suppression benefits.

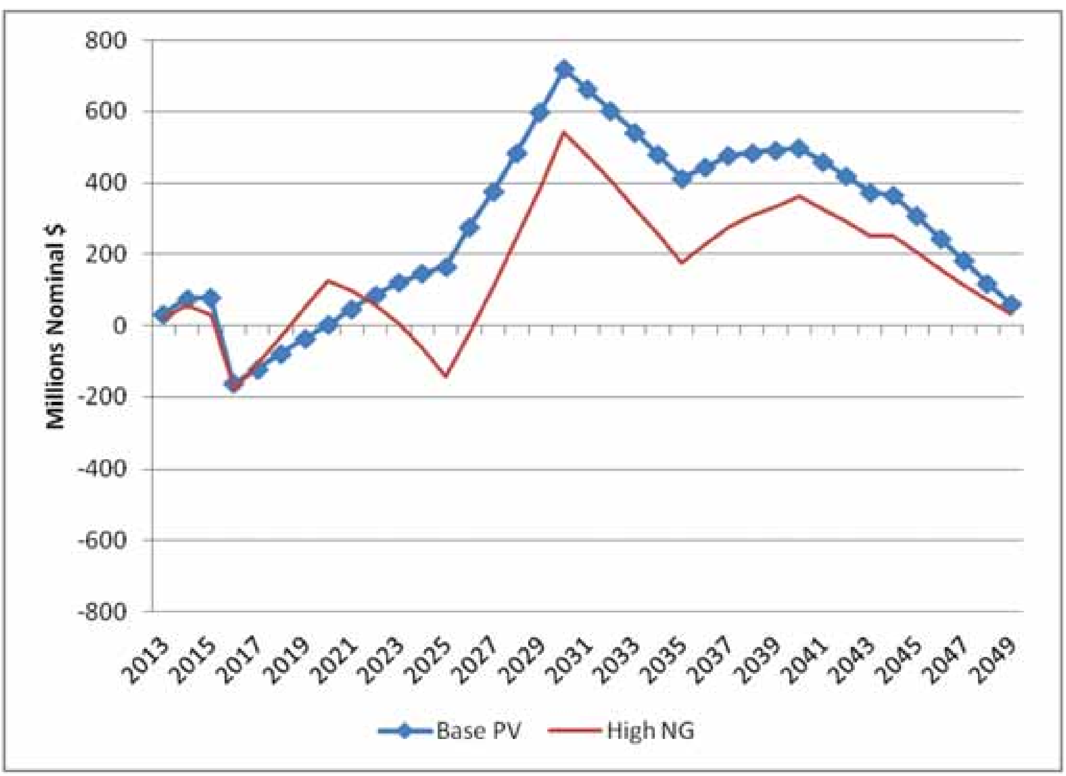

Figure 34. Net Costs, Base, High NG, Base Carbon, 2013-2049

Figure 37 shows the summary metrics for the High Natural Gas sensitivity case. Higher natural gas prices provide additional revenues to solar plants relative to base wholesale modeling assumptions, thus reducing net cost by almost NPV $1 billion. Higher natural gas prices also increase the wholesale price suppression benefits of solar, also reducing the overall net cost impact.

Table 37. Wholesale Price Suppression and Net Costs, Base Policy vs. High NG 201-2049, NPV 2011$

Million 2011$	Base	High Gas
Wholesale Price Suppression	(3,300)	(3,700)
Net Cost Impact	2,200	1,200

5.4.4 Sensitivity Analysis: Indian Point

The Indian Point nuclear generating station was assumed to be retired in the reference case. A final sensitivity analysis was conducted assuming continued operation of the Indian Point nuclear, to examine the impact on solar policies on direct rate impact and net cost of continued operation. Appendix 6 shows the results of this sensitivity analysis, which shows that the presence or absence of Indian Point has almost no impact on the costs or benefits of a PV policy.

6. NET JOBS AND MACROECONOMIC IMPACT ANALYSIS

6.1. Introduction

This chapter analyses the economic impacts of PV deployment in New York State by using elements identified in previous chapters as inputs to a REMI PI+ model of the New York economy. The chapter calculates direct job impacts in the PV industry as well as the net impacts on total employment and gross state product.

Key findings of this Chapter include:

- Deployment of PV to a level of 5,000 MW will create approximately 2,300 direct PV jobs associated with PV installation for the installation period (2013 – 2025) and an average of approximately 240 direct jobs per year associated with Operations and Maintenance (O&M) from 2025 – 2049.
- There will also be 600 jobs lost for the study period primarily as a result of the reduced need to expand and upgrade the distribution grid, a reduced need for conventional power plants, and reductions in in-state biomass fuel production.
- In terms of the total impact of the Base case PV deployment on the economy, there will be no net-job gain, in fact, modeling showed a net job loss of 750 jobs per year because of the impact of increased electricity rates. Gross state product (GSP) would be reduced by $3 billion between 2013 and 2049, representing a small annual decrease in GSP of less than 0.1%.
- The sensitivity analysis demonstrates that a low PV cost future would lead to economic growth, including an additional $3 billion in GSP, while a high cost future would lead to a reduction in GSP of $9 billion and a net-job loss on the order of 2,500 annual average jobs.
- This report analyzes only the impact of achieving a 5,000 MW goal. In reality, it is possible that the market will continue to grow beyond 2025 and that some jobs in the PV industry would be sustained. It may be of value to conduct further research to estimate the quantity of PV that would be replaced at the end-of-life, without additional New York State incentives.
- Subsidies at the scale required to achieve 5,000 MW of PV by 2025 would most likely have a small net-negative impact on the economy; however, continued support for PV is warranted given the promise of a low cost PV future.

This chapter is organized as follows:

- Section 6.2 presents an overview of the REMI macroeconomic impact analysis model
- Section 6.3 presents the types of direct economic effects on New York households and businesses that emerge from deploying PV generation investment, and key assumptions for how these effects will interact with the state's economy
- Section 6.4 presents specific REMI model inputs and key results for the Base PV Scenario (based on Base PV Costs and Base Deployment)
- Section 6.5 addresses the direct "PV-related" jobs implications for New York across all scenarios
- Sections 6.6 addresses direct job losses resulting from reduced levels of electricity generation and investment for future generating capacity and distribution system upgrades in New York
- Sections 6.7, 6.8 and 6.9 summarize, respectively, the REMI model inputs and results from the Base PV Scenario and sensitivity analyses exploring macroeconomic impacts under a low PV cost future, a high PV cost future
- Section 6.10 provides a summary of results
- Appendix 7 contains additional information on the REMI model and detailed inputs and results. This appendix also includes the results of a high natural gas price future sensitivity analysis.

6.2. Methodology

6.2.1 Overview of REMI *PI*+ Model

The REMI model (developed in 1986 by Regional Economic Models, Inc.[83]) is an advanced economic model that combines an input-output model at its core with an additional ability to forecast shifts in prices, competitiveness factors and business attraction over time. This latter feature makes the system dynamic and allows the model to "forecast" an economic trajectory under a set of conditions. These conditions can describe a reference case (sometimes called business-as-usual), or a proposed policy event that has economic implications.

A REMI model of the state of New York was chosen for the purposes of the Solar Study since (a) an estimate of macroeconomic effects from electric price suppression was sought, and (b) potential electric rate changes might be involved. These aspects make the REMI model uniquely qualified to address such changes compared to a simple input-output model.

Applications of the REMI model have been performed for assessment of energy efficiency, renewable energy and energy pricing policies include reports for California, Wisconsin, Iowa, Wyoming,

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83 See: http://www.remi.com/

Massachusetts, New Jersey, New England, other RGGI/NESCAUM states and the eastern Canadian provinces. Other applications using the REMI model to assess impacts of regulatory changes and shifts in energy fuels and technologies were studies for Maine, Missouri, Illinois, Michigan, Connecticut, Vermont, New Jersey, Florida, New York, other NESCAUM states, and the Midwest. A presentation of the REMI model structure and its feedback responses is included in Appendix 7.

6.2.2 Impact Analysis Capabilities

Using the dynamic annual forecasting capability of the REMI model, an alternative economic forecast can be generated reflecting the influence of a program/policy, proposed or already in effect. The economic impact (defined as jobs, or business output, dollars of gross state product, or labor income etc…) is defined as the difference in a specific year's metric with and without the program/policy. Figure 35 shows this process.

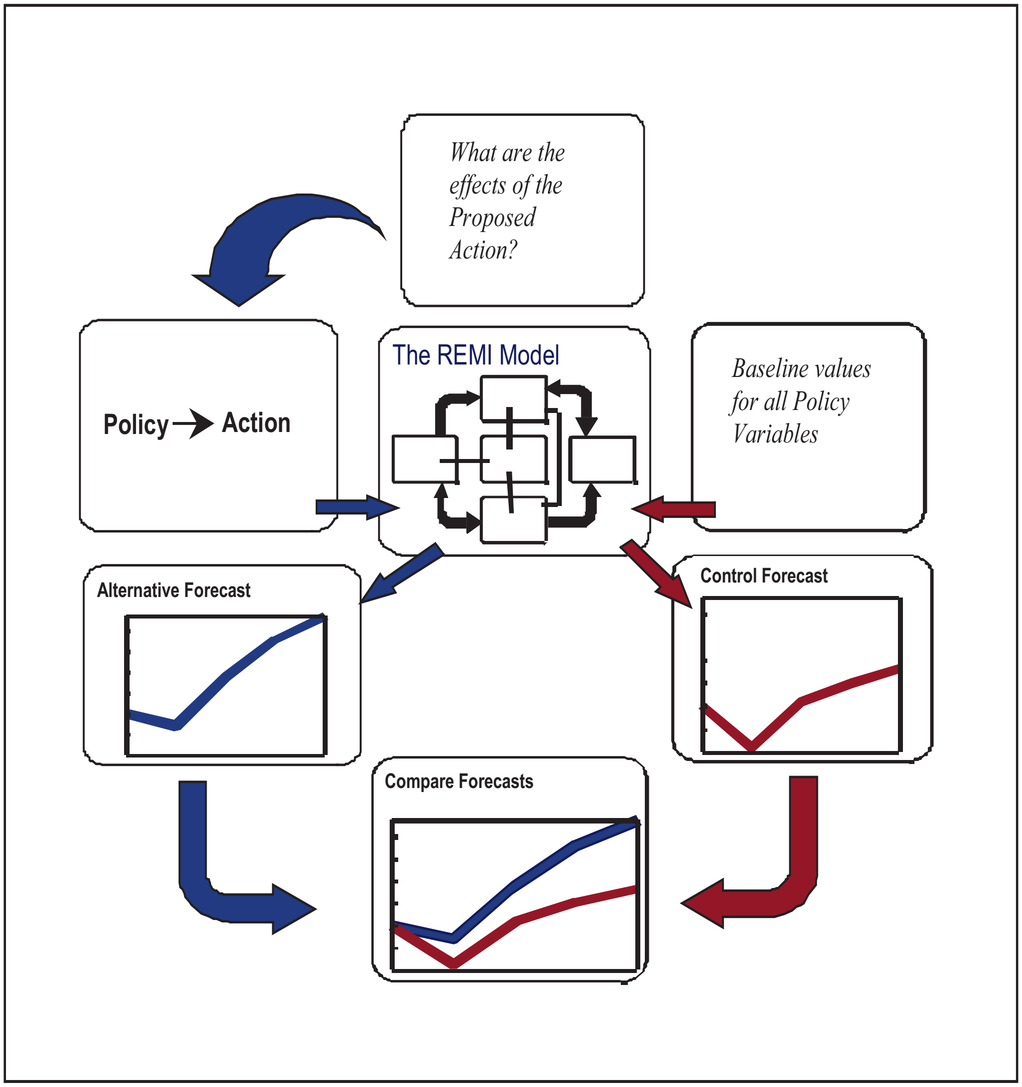

Figure 35. Identifying Annual Economic Impacts with a REMI Model (Source: Regional Economic Modeling, Inc.)

The end result is that the REMI model forecasts year-by-year changes in industry-level and statewide employment (or jobs), dollars of output, value-added (or gross state product), wages, labor income, personal income, exports, investment, prices, government spending, inflation, taxes, population, labor force, labor force participation rates, capital utilization by industry of the New York economy. Two key macroeconomic metrics are the focus of this study:

- **Jobs.** The number of workers (salaried or self-employed individuals, working in the private-sector or public sector, full or part-time) associated with changes in business sales as a result of the policy's overall effect. When summed over an analysis interval, jobs are measured in units of job years. A job year simply means one job for one year. When described in units of average annual job years, this refers to the number of persistent jobs that were created over a specified period of time (Council of Economic Advisers, 2009).
- **Gross State Product (GSP).** GSP is calculated as the value-added portion of business sales, which is the value of business sales minus cost of inputs from supplying (or intermediate) industries. GSP represents the sum of worker income and corporate (profit) income.

6.3. "Effects" from PV Deployed

The REMI macroeconomic impact analysis requires restating the results presented in prior chapters which describe by customer segment the PV system cost, performance and savings potential. This information must be aggregated to categories such as household sector or industry-level effects to appropriately target ratepayer implications. The influence of the PV deployment target to affect the monetary transactions of economic agents in New York (households, businesses, and public agencies) comprises the primary[84] effects.

Based on the definition of the solar PV deployment scenarios, three categories of primary effects were defined as inputs to the New York REMI model:

- **Energy Supplier Shifts.** Reductions in grid-provided electricity purchases will result in some in-state reductions in retail energy sales and in the operating and maintenance spending of existing generating units (including reduced outlays for predominantly imported fossil fuels), and reduced shareholder income to NY investors due to lower profits of in-state generators
- **Shifts among Equipment Manufacturers and Installers.** Reaching PV deployment targets will increase investment demand for systems and installation services. Some of this demand could produce increased sales for New York-made products or components, and will create sales for installation

[84] Primary effects are typically referred to as direct effects, as opposed to multiplier effects, consisting of indirect and induced effects.

services employing New York laborers and in-state wholesale distributors. In addition, investment demand will decline for anticipated generating units and distribution system expansion that would have been built in New York were it not for the solar generation.

- **Ratepayer Effects.** Electric utility ratepayers may incur a combination of policy-related rate changes. The first is a price suppression effect. Less than 100% of the price suppression effect estimated in Chapter 5 is expected to have an impact on the NY economy as the price suppression benefit realized by LIPA and NYPA customers is balanced against a reduction in LIPA and NYPA's expenditures in the NY economy. LIPA and NYPA account for approximately 27 percent of the price suppression dollars, so the macroeconomic impact will be driven by 73 percent of the total dollar value of the price suppression effect. The second is the wholesale value of avoided generation, along with avoided Main Tier RPS compliance costs associated with a reduced need for New York State to purchase renewable energy attributes. A third is avoided investment costs for distribution system upgrades and expansion. Each will serve to reduce rates. The fourth effect absorbed by ratepayers is the net "cost" of the program, the solar premium calculated relative to the wholesale value of solar energy production and associated capacity. A positive net solar subsidy cost increases rates for energy customers.
- A presentation of how these primary effects are mapped into specific policy variable levers in the REMI model is included in Appendix 7.

6.3.1 Assumptions Used for the REMI Analysis

The "mapping" of policy effects into specific REMI levers and specific industries explains a majority of how the REMI scenarios will be structured. One remaining issue in introducing the policy's effects related to changes in electric generation capacity investment (or PV capacity investment), as well as related O&M changes, is how much of these changes mean a change in sales for New York firms. This is typically a question concerning equipment purchases but does not preclude the installation (labor) portion of the investment or the O&M.

For each REMI modeling scenario's annual PV investment, the assumptions shown in Table 146 in Appendix 7 were used. For example, for solar installation dollars representing 16% of total system investment, 95% are assumed to be handled by NY laborers and enters the REMI NY model as an OUTPUT (sales) increase for the maintenance and repair construction sector representing 70 percent as labor payments and 30 percent as the balance of value-added. What does not enter the REMI model is the portion awarded to installation firms from outside NY. For the manufactured content part of the investment cost, 5 percent is assumed to be sales from NY manufacturers across the supply-chain, and the mark-up value of the entire equipment investment will enter the REMI NY model through the Wholesale Trade industry. For PV O&M requirements, all of the installation labor will be directed to New York Repair &

Maintenance construction industry, and only the mark-up value of the materials and parts will enter the REMI NY model through the Wholesale Trade industry.

For each scenario's annual reduced investment from "reference case" electric generating technologies, the dollars allocated to relevant capital goods-supplying industries are entered into the REMI NY model as changes in demand and the REMI model's regional purchase coefficient[85] ("RPC") will determine how much of the demand change becomes an output (sales) change occurring within New York businesses. The labor cost component of building various types of generating units would rely upon in-state construction firms and be handled as a loss of construction contract value.

6.4. Characterization of Policy Case PV Economic Elements

Table 38 and Table 39 present the cumulative value in 2011 dollar of analysis case effects from 2013 through 2049. These tables organize the "stimulative" elements of the policy design (Table 38) and the "depressive" elements (Table 39). Comparing the far right column of Table 38 shows that the "depressive" direct elements carry a value (in millions of 2011$) at least 1-to-2 times more pronounced for Base PC scenario, and the High PV Cost sensitivity than their "stimulative" elements. The Low PV Cost case, on the other hand, has positive effects that are twice its Depressive effects. As the "notes" field indicates, some policy elements do not exert an effect for the entire analysis time horizon. Also, with respect to two of the positive elements, investment demand and O&M demand, and two of the Depressive elements, generating capacity reduced investment and reduced variable operating expenses of generating units, the values of key significance are those dollars that represent sales for NY businesses. The NY sales amounts shown represent 31% and 63% respectively of investment and O&M demands as a result of current reliance on NY manufactured solar components and replacement parts. Price suppression will play a role as a large stimulative element (benefitting NY ratepayers) as well as a smaller depressive element experienced by NY-based generators and the portion of their shareholders that are NY-based.

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85 The *RPC* is an industry-specific and region-specific parameter that is econometrically measured within economic impact models (input-output models as well as CGE models). This parameter (based on historical trend of data) ranges from a value of *0 to 1.0*, with the lower bound indicating that none of the local (or in-state) production from an industry is sold to meet local demand. The upper bound would indicate that 100 percent of local production is sold to fulfill local demand.

Table 38. Value of Positive Direct Effects by Analysis Case (M2011$)

	STIMULATIVE					
Model Case	Price Suppression all ratepayers	Avoided RPS Payments all ratepayers	Avoid Distribution Investment all ratepayers	**Investment to NY**	**O&M $ to NY Suppliers**	Cumulative m2011$
Base	3911	150	1756	4088	1393	11,299
Low PV	B	B	B	2923	B	10,133
High PV	B	B	B	5254	B	12,464
Notes:	ends 2039	ends 2025		ends 2025		

Table 39. Value of Negative Direct Effects by Analysis Case (M2011$)[86]

	DEPRESSIVE						
Model Case	net Cost of SOLAR SUBSIDY all ratepayers	Avoided Investment to NY	NY Biomass Feedstock Reduction*	Reduction to NY Suppliers of Variable Operating Costs	Reduction in NY Generators' Profits (due to Price Suppression)	Reduction in Distribution System Expansion	Cumulative m2011$
Base	-13759	-754	-420	-321	-184	-1756	(17,194)
Low PV	-4494	B	B	B	B	B	(7,929)
High PV	-25422	B	B	B	B	B	(28,857)
Notes:		ends 2030					

6.5. Direct 'PV-Related' Jobs

The positive and depressive effects of economic transactions that initiate macroeconomic changes comprise a pool of direct effects and then, as an economy adjusts to the direct effects, subsequent multiplier responses amplify the direct effects into total effects. Some direct effects, such as changed investment demand, or changed business sales imply direct jobs. Some do not, such as a change in electric rates. The

86 Note: Only biomass is shown since it is the one feedstock likely to affect within state suppliers (whereas coal, oil and gas are highly imported).

direct effect associated with electricity rate changes is a change in the spending levels of the customer. Subsequently jobs would be affected through supplier adjustments[87] or consumer spending levels[88].

No economic model has an industry designated as "solar" or "renewable", just as these same models do not have an industry designated "tourism." The economic activity behind each of these labels is the result of services and manufactured content all bundled together. When economists are asked to estimate impacts within a region in terms of the green jobs, or the solar jobs, what is required is an articulation of the in-state activity captured along the supply-chain that ultimately puts a system on a roof-top. A challenge remains, however, that some of the activities along the supply-chain do not derive 100% of their annual revenues from PV related work. Some installation laborers work on non-green activities, and some wholesalers cater to multiple business lines, for example.

Chapter 1.3 documented New York's presence in the "PV industry" encompassing components manufacturing, silicon feedstock production, system installation, system design and public agency staff focused on PV R&D as well as policy definition. The parameters in Table 145 and Table 146 of Appendix 7 determine "NY capture" of PV O&M, and the PV capital investment clearly will call on some of those 556 solar jobs enumerated by in the Brooking's *Clean Economy* study (Brookings-Battelle, 2010)**.** [89]

The following approach was taken to identify direct "solar" jobs (since it cannot come directly from the REMI model):

- Rely on the value of PV investment demand and O&M spending requirements and the segmentation of those dollars
- Apply the information from Table 145 and Table 146 regarding allocation of spending into different purchases (industries) and the proportion New York businesses would fulfill of manufacturing (five percent from NY) or mark-up. Mark-up is the local value-added attributed to distributors, or retail shops as they handle their purchased product for final sale (five percent of equipment cost) or installation services (95 percent)
- Direct project dollars for various in-state industries can be re-stated as "jobs" by using each industry's dollar output-per-worker which is available from the REMI NY model.

Note that because crystalline modules are currently the most widely-used technology, it is assumed that this technology will be used in New York for purposes of this analysis. It is not possible to know whether these imported modules would have been made using silicon produced in New York.

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87 Effects on Supplier transactions are termed "indirect" effects.
88 Effects from Household spending is termed "induced effects"
89 The jobs were inventoried for 2010. July 2011 publication.

Table 40, 41, and 42 present those direct jobs that are closely aligned with each scenario's PV adoption activity, in terms of average annual impact. These are identified separately for the installation interval and ongoing O&M since they have different durations. All scenarios deploy the same MWs of PV capacity.

Table 42 will differ from the Base PV scenario since the PV installed cost assumptions alter the amount of investment.

Table 40. Direct "PV" Jobs for Base PV Scenario

Industry involved	Average Annual Impact	
	Installation	O&M
	2013 to 2025	2013 to 2049
Construction and Installation	1773	233
Engineering	57	na
Legal Services	57	na
Finance	158	na
Wholesale Trade	162	2
Manufacturing	59	2
Total (may differ due to rounding)	**2300**	**240**

Note: High Gas Cost Case has same implication for direct "PV-related" Job impacts

Table 41. Direct "PV" Jobs from Low PV Cost Case

Industry involved	Average Annual Impact	
	Installation	O&M
	2013 to 2025	2013 to 2049
Construction _ Labor	1551	na
Engineering	111	na
Legal Services	40	na
Finance	40	na
Wholesale Trade	115	2
Manufacturing	44	2
Total (may differ due to rounding)	**1900**	**4**

Table 42. Direct "PV" Jobs from High PV Cost Case

Industry involved	Average Annual Impact	
	Installation	O&M
	2013 to 2025	2013 to 2049
Construction and Installation	2242	Na
Engineering	73	Na
Legal Services	73	Na
Financial Services	204	Na
Wholesale Trade	209	237
Manufacturing	78	2
Total (may differ due to rounding)	**2900**	**240**

Figure 36 shows the phase-specific annual direct job impacts for the Base PV Scenario case, while Figure 37 shows how direct annual solar-related job impacts from the installation and O&M spending phases compare between Base and Low and High PV Cost Cases. Figure 38 shows the allocation to specific industries of the direct solar-related jobs for the installation phase in the Base PV Scenario.

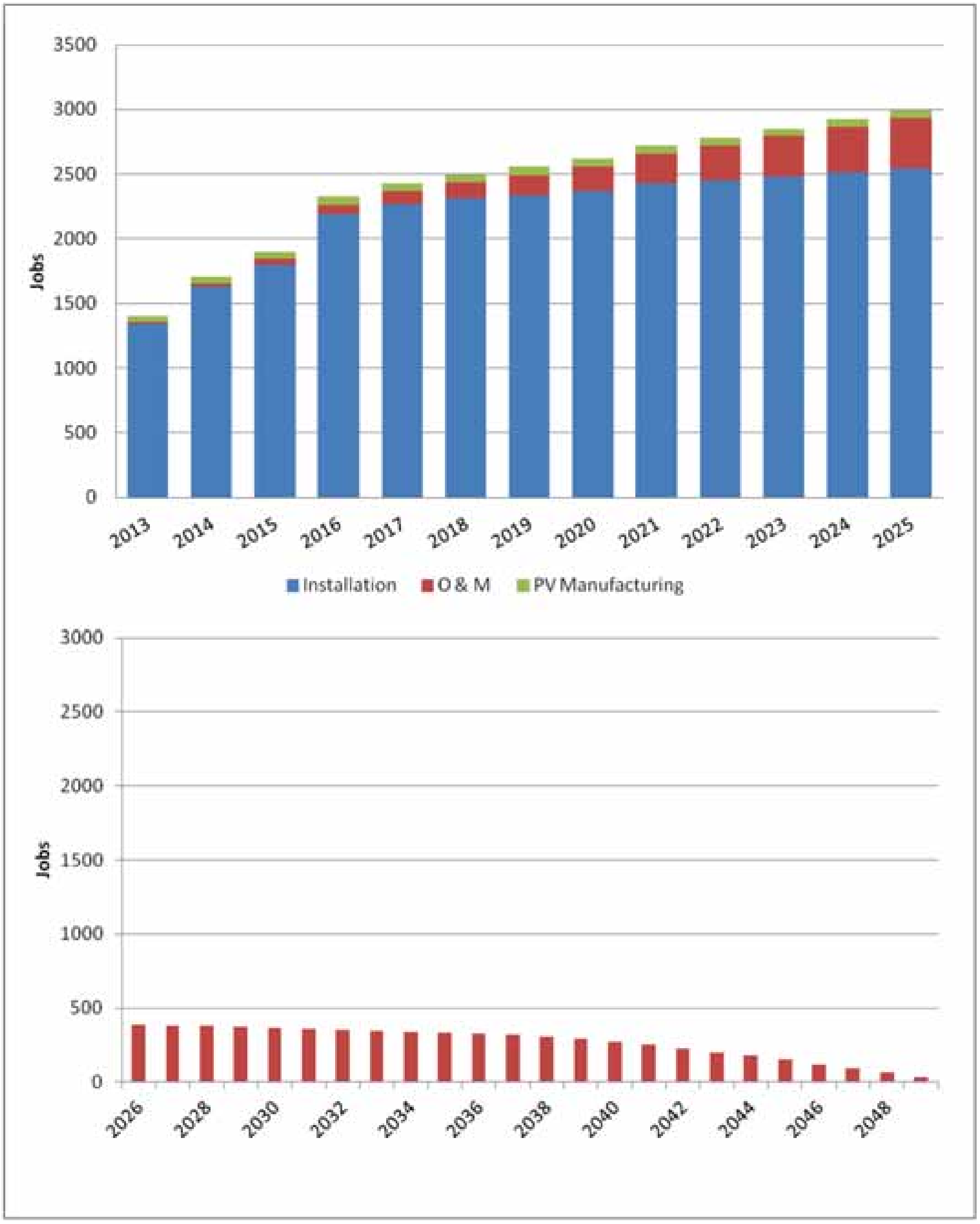

Figure 36. Source of Annual Direct PV-related Job Changes - Base PV Scenario

Note: High Natural Gas Cost Case has same implication for direct “solar-related” Job impacts

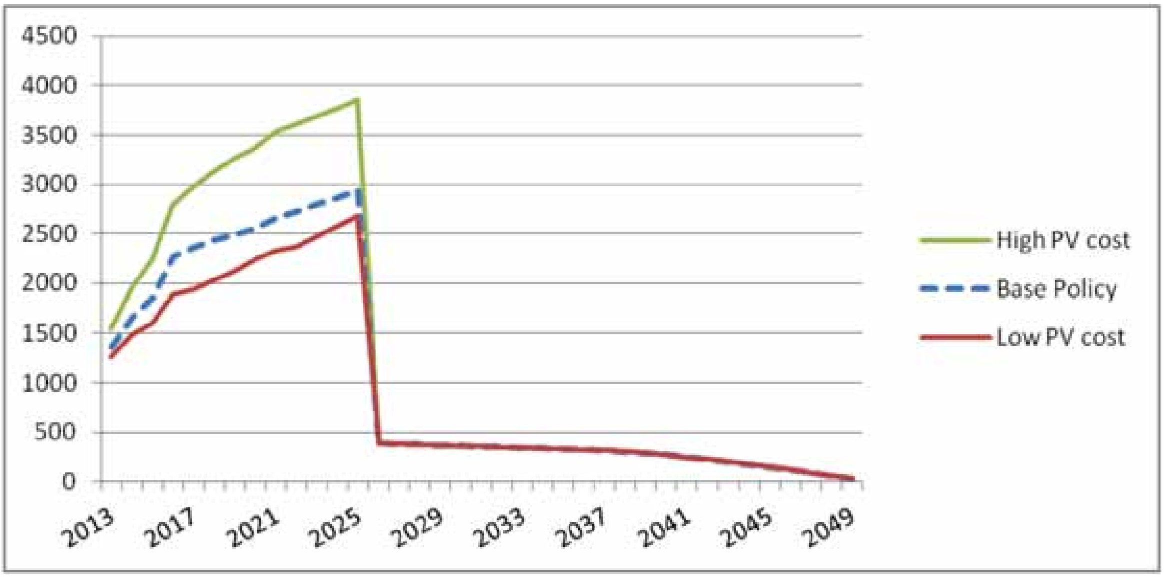

Figure 37. Comparison of Installation and O&M Phase Direct "PV-related" Job impacts under different PV Cost cases

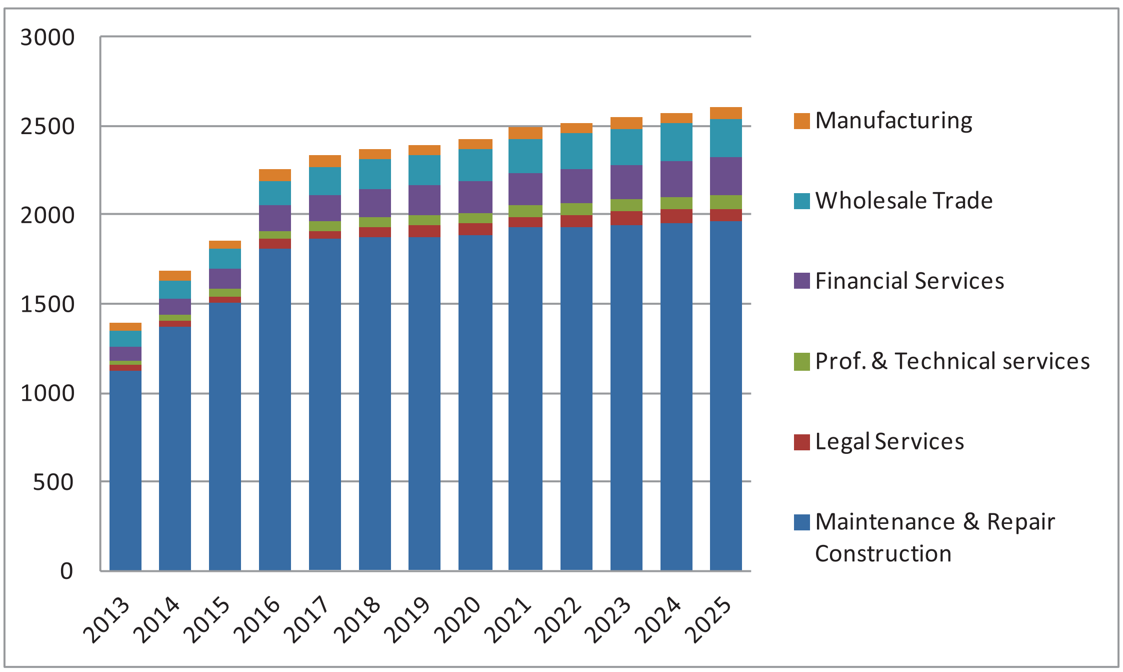

Figure 38. Installation Phase Annual Direct PV-related Job Changes by Industry

Base PV Scenario

Note: High Gas Cost Case has same implication for direct "solar-related" Job impacts

6.6. Direct Job Losses

Due to the decoupled nature of electric generation in New York, the utility companies will be "made whole" for any lost revenues. Generating units operating at reduced levels will make lower purchases of fuel (some sourced from New York such as the biomass, but most sourced outside of New York) and other variable O&M needs. There will also be reduced construction and capital goods for upgrades to the distribution system and generating capacity additions. Table 43 portrays the average annual direct jobs forfeited in the Base PV Scenario (identical for Low PV Cost and High PV Cost sensitivities as well). The reduction in NY-sourced biomass fuel purchases exerts the larger effect of the two reduced purchase stream by NY generators. The biomass jobs forfeited will be in the Forestry/Logging sector. The IPM model predicted a small reduction (3% of the value of averted generation) in other variable operating costs and only a portion of that affects NY suppliers. Those suppliers are across many industries but the overall job forfeit is small in comparison to the in-state biomass feedstock reduction.

Table 43. Base PV Scenario Case Direct Jobs Lost with Suppliers to New York's Generation System, 2013 to 2049

Base (Low & High PV cost)	**Avg. Annual Jobs**
Biomass feedstocks lost	-153
Reductions in Other Variable Operating Purchases	0
Reduced investment in Generating Capacity	-337
Distribution System upgrade deferrals	-126
Total (may differ due to rounding)	-620

New York's direct job loss resulting from reductions in future investment for generating capacity additions and for improvements to the distribution system are shown in Figure 39 (the Base PV Scenario and two other PV cost cases). The reduced pace of upgrades for and expansion of the electric distribution system is what provides a ratepayer benefit in the form of averted investment cost. Still, that investment would be associated with supporting construction labor (assumed to be 15 percent of the annual investment) and some NY manufacturing[90] (from Electric equipment manufacturing) on the balance of system investment – the remaining 85 percent. The annual deferred investment is of equal magnitude to the direct ratepayer benefit (uniform for all three PV price scenarios).

90 The equipment cost of the distribution system investment deferrals as "demand" and thus the REMI model *regional purchase coefficient* would determine how much of the demand represents NY sales. That amount is near 10 percent.

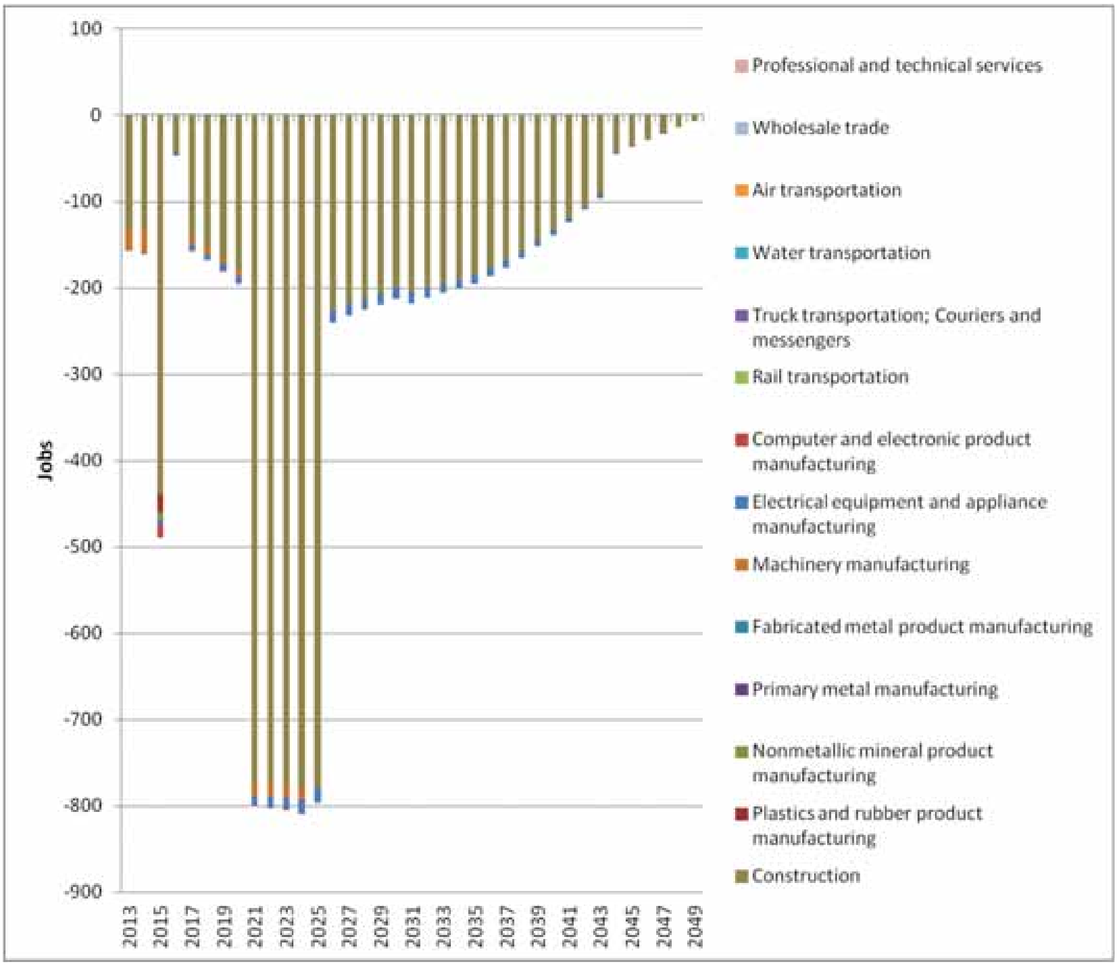

Figure 39. Base PV Scenario Direct Jobs Lost from Reduced Investment for Generating Capacity and Distribution System Upgrades

6.7. Base PV Deployment Scenario – Inputs & Results

6.7.1 Scenario Characteristics

The central analysis of this chapter represents a comparison of the Base PV Scenario to the reference case. Specifically, the characteristics of this scenario include:

- PV systems installed up through 2025 worth 4,585 MW across customer segments
- PV price is from the Base LCOE case described in Chapter 4
- REMI scenario runs are conducted covering the period 2013 through 2049 to capture the assumed 25 year economic life of PV installations through 2025
- In-state manufacturing will provide five percent of the equipment/components investment.

Subsequent sensitivity analyses for comparison to this base case are discussed in the following sections including a chance for New York manufacturers to benefit from some of the investment.

6.7.2 Scenario Inputs

The following information shown in Table 44 and Table 45 was derived in the course of the solar premium modeling analysis described in Chapter 5, and incorporates IPM model results described therein.

Table 44. Scenario Positive Effects, Select Years and Cumulative through 2049

	Direct Effect (mil 2011$)	2013	2019	2025	2030	2040	2049	Cumulative
STIMULATIVE	New Investment **Demand** PV	**560.0**	**1006.4**	**1095.7**	**0.0**	**0.0**	**0.0**	**12203.3**
	New O&M spending	**2.7**	**43.7**	**139.2**	**159.1**	**182.5**	**31.3**	**2358.8**
	Electric Price Suppression for ratepayers	**-2.1**	**-261.5**	**-343.7**	**-3.1**	**0.0**	**0.0**	**-3911.3**
	Residential	-0.7	-88.5	-116.3	-1.0	0.0	0.0	-1323.3
	Small C&I	-1.1	-135.0	-177.5	-1.6	0.0	0.0	-2018.0
	Large C&I	-0.3	-32.7	-43.0	-0.4	0.0	0.0	-491.5
	Government	0.0	-5.2	-6.9	-0.1	0.0	0.0	-78.5
	Avoided RPS Payments to ratepayers	**-3.7**	**-12.7**	**-12.1**	**0.0**	**0.0**	**0.0**	**-150.4**
	Residential	-1.3	-4.3	-4.1	0.0	0.0	0.0	-50.9
	Small C&I	-1.9	-6.6	-6.2	0.0	0.0	0.0	-77.6
	Large C&I	-0.5	-1.6	-1.5	0.0	0.0	0.0	-18.9
	Government	-0.1	-0.3	-0.2	0.0	0.0	0.0	-3.0
	Avoided Ratepayer Payments for Distribution Expansion	**-2.4**	**-31.5**	**-81.0**	**-77.0**	**-56.7**	**-3.2**	**-1756.3**
	Residential	-0.8	-10.7	-27.4	-26.1	-19.2	-1.1	-594.2
	Small C&I	-1.2	-16.4	-42.2	-40.2	-29.6	-1.7	-915.9
	Large C&I	-0.3	-3.8	-9.7	-9.3	-6.8	-0.4	-210.9
	Government	0.0	-0.6	-1.6	-1.5	-1.1	-0.1	-35.3

Table 45. Scenario Depressive Effects, Select Years and Cumulative through 2049

	Direct Effect	2013	2019	2025	2030	2040	2049	Cumulative
DEPRESSIVE	**Electric rate increases (solar subsidy)**	**45.7**	**396.4**	**716.4**	**555.9**	**312.7**	**27.5**	**13759.1**
	Residential	15.5	134.1	242.4	188.1	105.8	9.3	4655.1
	Small C&I	23.8	206.7	373.6	289.9	163.1	14.3	7175.2
	Large C&I	5.5	47.6	86.0	66.8	37.6	3.3	1652.6
	Government	0.9	8.0	14.4	11.2	6.3	0.6	276.2
	Future Generating Capacity divestment	**-92.0**	**-43.1**	**-173.8**	**12.5**	**0.0**	**0.0**	**-1281.8**
	Electric Utility O&M purchases	**-0.2**	**-21.9**	**-28.2**	**-19.7**	**-12.6**	**-21.0**	**-637.8**
	Electric Utility Fuel purchases	**-0.7**	**-81.5**	**-168.8**	**-139.0**	**-210.3**	**-316.4**	**-5996.6**
	Reduced NY Generator Profits (Price Suppression)	**-0.1**	**-12.3**	**-16.2**	**-0.1**	**0.0**	**0.0**	**-183.8**
	Reduced Distribution System Expansion	**-2.4**	**-31.5**	**-81.0**	**-77.0**	**-56.7**	**-3.2**	**-1756.3**

6.7.3 Scenario Results

Table 46 presents aggregate total (the policy direct effects plus the multiplier responses) macroeconomic impacts (as differences, and as percent change from the New York reference case).

Table 46. Aggregate Impacts of the Base PV Scenario

Differences from Baseline Level								
Variable	**Units**	**2013**	**2019**	**2025**	**2030**	**2040**	**2049**	**NPV**
Total Employment	(Jobs)	1549	1821	-188	-3441	-1396	-43	N/A
Gross State Product	Billions of 2011$	0.156	0.178	-0.164	-0.716	-0.481	-0.186	-2.931
Output	Billions of 2011$	0.204	0.198	-0.374	-1.144	-0.756	-0.293	-5.399
PCE-Price Index	2005=100 (Nation)	0.004	0.013	0.031	0.050	0.033	0.013	N/A
Real Disposable Personal Income	Billions of 2011$	0.033	0.008	-0.240	-0.562	-0.354	-0.133	-3.125
Population	People	227	1309	-428	-3898	-4752	-2223	N/A
Percent Change from Baseline Level								
Variable	Units	**2013**	**2019**	**2025**	**2030**	**2040**	**2049**	
Total Employment	%	0.013	0.015	-0.001	-0.025	-0.010	0.000	N/A
Gross State Product	%	0.011	0.010	-0.008	-0.031	-0.017	-0.006	N/A
Output	%	0.009	0.006	-0.011	-0.030	-0.016	-0.006	N/A
PCE-Price Index	%	0.004	0.009	0.019	0.027	0.013	0.004	N/A
Real Disposable Personal Income	%	0.004	0.001	-0.020	-0.042	-0.021	-0.007	N/A
Population	%	0.001	0.006	-0.002	-0.017	-0.019	-0.008	N/A

Annual macroeconomic impacts for the Base PV Scenario are initially positive for jobs and dollars of gross state product (GSP) as beneficial ratepayer changes (through price suppression, savings related to avoided RPS payments and avoided distribution system investments) and demand for PV systems and their installation stimulate the New York economy. After 2025, the MW targets have been met and the investment demand stimulus ends. Other policy elements are responsible for exerting a more pronounced net negative effect through 2049. Those elements include negative ratepayer effects, from the net cost of the solar policy, reduced investment in generating capacity for New York, and reduced purchases of biomass fuel and other variable operating expenses when existing generators operate at lower levels). In addition, the IPM analysis of price suppression benefits for ratepayers described in Chapter 5 ceases by 2039. As a result New York would have approximately 3,400 fewer jobs in 2030 and $0.7 billion less in GSP than it would have in the reference case. These annual changes are small and represent 0.02% and 0.03% of their reference case values respectively. The average annual net job impact is a loss of approximately 750 jobs, and the NPV of cumulative GSP impacts (at a real discount rate of 5.1%) is a decrease of $3 billion.

The impacts on employment and gross state product (GSP) are decomposed by scenario effect (Table 47) to provide a better understanding of how the mix of stimulative and depressive elements alters employment and GSP. Among the positive elements of the Base PV Scenario, the first 13 year of PV investment activity support the largest job impacts, followed by the effect from price suppression on ratepayers. The first six years of PV investment activity will also contribute the most to positive GSP impacts, until price suppression benefits ramp up and effect businesses as ratepayers unleashing their ability to create more value-added (GSP). After 2025 when the PV investment phase is completed the PV O&M spending and the ratepayer benefit provided through both avoided RPS payments and distribution system upgrades and expansion provide the largest stimulus to the economy for both jobs and dollars of GSP. Once the price suppression effects expire in 2039, the loss of the largest ratepayer benefit cuts into energy consumers' budgets and forfeits jobs. Similarly, for the expiration of avoided RPS compliance costs after 2025 jobs will be forfeited starting around 2027. Both avoided distribution system investment costs (the remaining ratepayer benefit) and persistent (yet modest level of) PV O&M spending will exert continual positive annual impacts on jobs and dollars of GSP.

Among the depressive elements associated with the Base PV Scenario case (as will be seen with the other cases), the cost of the policy (i.e. the net solar subsidy cost) on ratepayers is the most pronounced of all depressive effects extending well through the 37 year interval. The lost investment demand for new generating capacity also causes the NY economy to shed jobs and dollars of GSP. That lost demand is through 2030 as identified in the IPM model results. After 2030, it is the persistent reduction in biomass fuel purchases that forfeits NY jobs and dollars of GSP. Other direct sources for job loss post-2030 include construction labor not needed due to deferred distribution system upgrades, along with the replacement equipment (85 percent of the annual investment, with 10 percent provided by NY manufacturers per the REMI model regional purchase coefficient), and lost economic activity through reduced profit income to NY shareholders (6.4 percent of the shareholders assumed based on NY population share) of NY generating plants as a result of price suppression.

Table 47. Decomposed Employment & GSP Impacts of the Base PV Scenario

Total Employment (Annual Job Impacts)	**2013**	**2019**	**2025**	**2030**	**2040**	**2049**	**Avg. Annual Impact**
Investment PV (installation & soft costs)	1897	2674	2611	-228	117	112	880
Investment NY Manufactured content	106	135	119	-18	-2	-3	39
Electricity Price Suppression all ratepayers	16	2058	2613	194	-154	-135	733
Avoided RPS payments (ratepayers)	25	107	96	-5	-11	-9	29
Avoided Ratepayer Payments for Distribution Expansion	17	231	588	556	317	-45	311
Increased Demand from PV O&M spending	22	217	524	445	318	27	293
Reduced Purchase of Other variable O&M	-1	-103	-116	-69	-40	-59	-64
Increased Electric rates due to solar subsidy	-302	-2945	-5225	-3948	-1517	363	-2408
Decreased GEN Capacity Investments	-223	-122	-857	97	-16	-14	-154
Reduced Fuel Feedstock Purchase (Biomass, Coal, Oil/Gas)	-2	-280	-268	-234	-267	-277	-252
Reduced Distribution System Expansion	-8	-104	-228	-246	-144	-1	-139
Reduced Profits NY Generators (Price suppression)	0	-47	-47	15	0	-4	-15
Total	**1500**	**1800**	**-190**	**-3400**	**-1400**	**-43**	**-750**

GSP (billion 2011$)	**2013**	**2019**	**2025**	**2030**	**2040**	**2049**	**NPV**
Investment PV (installation & soft costs)	0.188	0.274	0.266	-0.064	0.003	0.009	2.133
Investment NY Manufactured content	0.015	0.025	0.025	-0.002	0.000	0.000	0.199
Electricity Price Suppression all ratepayers	0.002	0.348	0.551	0.205	0.074	0.031	3.884
Avoided RPS payments (ratepayers)	0.003	0.020	0.022	0.006	0.002	0.001	0.182
Avoided Ratepayer Payments for Distribution Expansion	0.002	0.037	0.113	0.133	0.115	0.033	1.179
Increased Demand from PV O&M spending	0.002	0.019	0.046	0.038	0.026	-0.005	0.382
Reduced Purchase of Other variable O&M	0.000	-0.020	-0.025	-0.015	-0.010	-0.020	-0.243
Increased Electric rates due to solar subsidy	-0.036	-0.492	-1.053	-1.021	-0.679	-0.226	-10.067
Decreased GEN Capacity Investments	-0.019	-0.010	-0.079	0.021	0.001	-0.001	-0.293
Reduced Fuel Feedstock Purchase (Biomass, Coal, Oil/Gas)	0.000	-0.009	-0.007	-0.004	-0.007	-0.013	-0.113
Reduced Distribution System Expansion	0.000	-0.008	-0.018	-0.016	-0.007	0.006	-0.147
Reduced Profits NY Generators (Price suppression)	0.000	-0.005	-0.004	0.004	0.001	-0.001	-0.026
Total	**0.16**	**0.18**	**-0.16**	**-0.72**	**-0.48**	**-0.19**	**-2.900**

The above decomposed impacts are depicted in Figure 40 and Figure 41 for employment and GSP respectively.

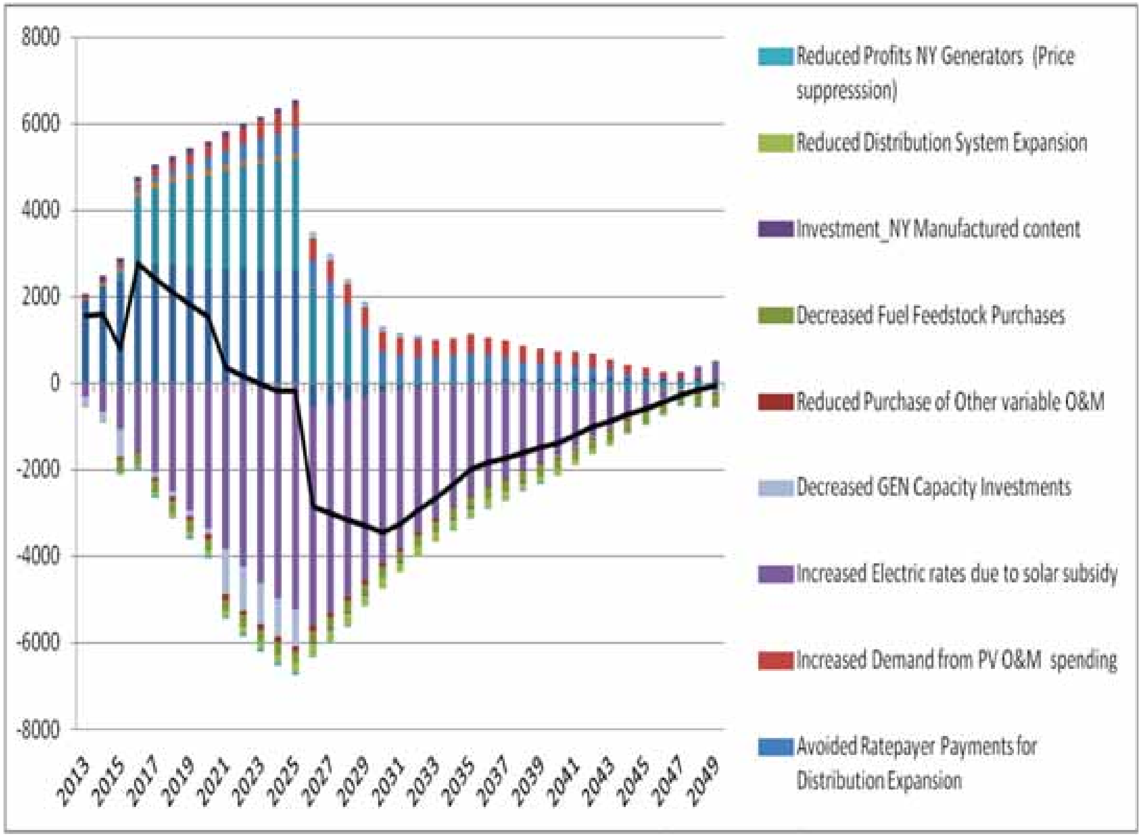

Figure 40. Employment Impacts of Base PV Scenario

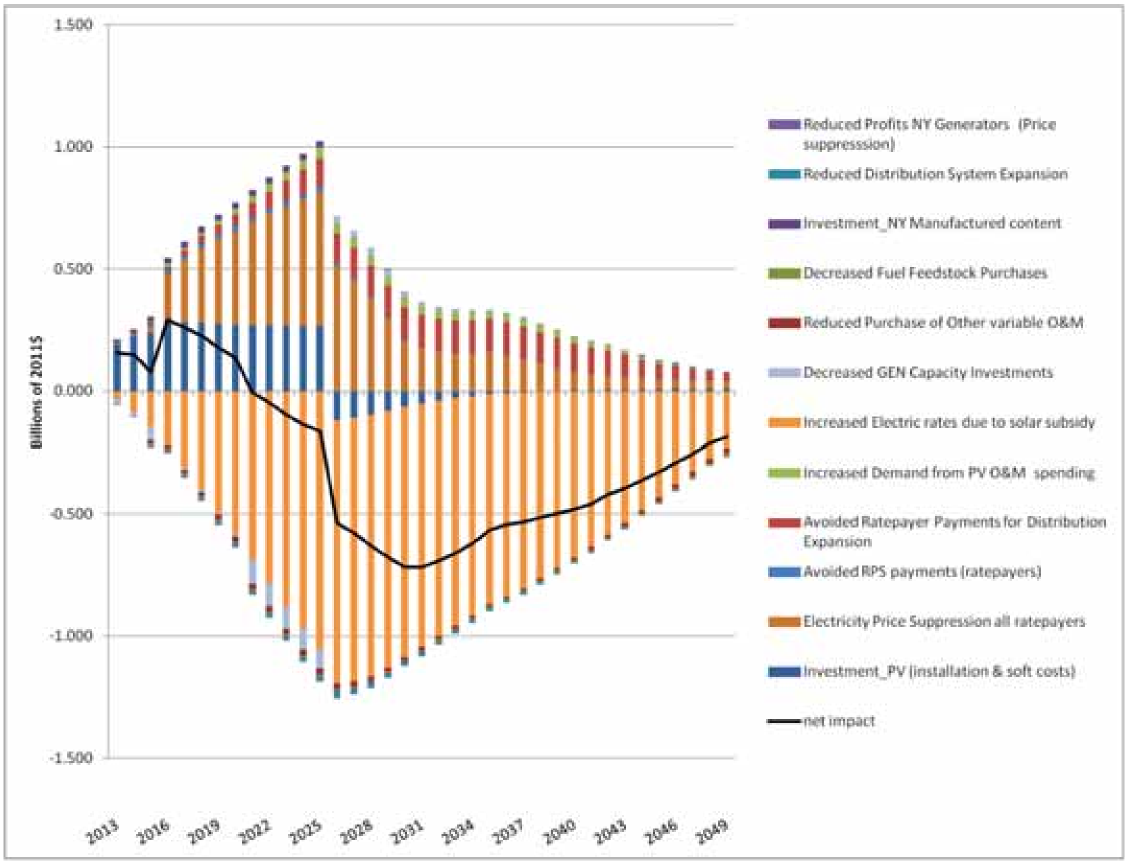

Figure 41. GPS Impacts of Base PV Scenario

6.8. Low PV Cost Scenario – Inputs & Results

6.8.1 Scenario Characteristics

This sensitivity case varies from the Base PV Scenario by the PV costs. It utilizes the installed costs, O&M costs and the LCOEs from the Low PV Cost Future case described in Chapter 3.

6.8.2 Scenario Inputs

The information shown in Table 48 and Table 49 was derived in the course of the solar premium modeling analysis described in Chapter 5, and incorporates IPM model results described therein.

Table 48. Low PV Cost Scenario Positive Effects, Select Years and Cumulative through 2049 (M 2011$)

	Direct Effect (mil 2011$)	2013	2019	2025	2030	2040	2049	Cumulative
STIMULATIVE	New Investment **Demand** PV	**505.8**	**710.9**	**726.4**	**0.0**	**0.0**	**0.0**	**8723.2**
	New O&M spending	**2.7**	**43.7**	**139.2**	**159.1**	**182.5**	**31.3**	**2358.8**
	Electric Price Suppression for ratepayers	**-2.1**	**-261.5**	**-343.7**	**-3.1**	**0.0**	**0.0**	**-3911.3**
	Residential	-0.7	-88.5	-116.3	-1.0	0.0	0.0	-1323.3
	Small C&I	-1.1	-135.0	-177.5	-1.6	0.0	0.0	-2018.0
	Large C&I	-0.3	-32.7	-43.0	-0.4	0.0	0.0	-491.5
	Government	0.0	-5.2	-6.9	-0.1	0.0	0.0	-78.5
	Avoided RPS Payments to ratepayers	**-3.7**	**-12.7**	**-12.1**	**0.0**	**0.0**	**0.0**	**-150.4**
	Residential	-1.3	-4.3	-4.1	0.0	0.0	0.0	-50.9
	Small C&I	-1.9	-6.6	-6.2	0.0	0.0	0.0	-77.6
	Large C&I	-0.5	-1.6	-1.5	0.0	0.0	0.0	-18.9
	Government	-0.1	-0.3	-0.2	0.0	0.0	0.0	-3.0
	Avoided Ratepayer Payments for Distribution Expansion	**-2.4**	**-31.5**	**-81.0**	**-77.0**	**-56.7**	**-3.2**	**-1756.3**
	Residential	-0.8	-10.7	-27.4	-26.1	-19.2	-1.1	-594.2
	Small C&I	-1.2	-16.4	-42.2	-40.2	-29.6	-1.7	-915.9
	Large C&I	-0.3	-3.8	-9.7	-9.3	-6.8	-0.4	-210.9
	Government	0.0	-0.6	-1.6	-1.5	-1.1	-0.1	-35.3

Table 49. Low PV Cost Scenario Depressive Effects, Select Years and Cumulative through 2049 (M 2011$)

	Direct Effect	2013	2019	2025	2030	2040	2049	Cumulative
DEPRESSIVE	**Electric rate change (solar subsidy)**	**33.7**	**231.2**	**246.1**	**157.6**	**49.2**	**1.0**	**4493.6**
	Residential	11.4	78.2	83.3	53.3	16.6	0.3	1520.3
	Small C&I	17.6	120.5	128.3	82.2	25.7	0.5	2343.4
	Large C&I	4.0	27.8	29.6	18.9	5.9	0.1	539.7
	Government	0.7	4.6	4.9	3.2	1.0	0.0	90.2
	Future Generating Capacity divestment	**-92.0**	**-43.1**	**-173.8**	**12.5**	**0.0**	**0.0**	**-1281.8**
	Electric Utility O&M purchases	**-3.7**	**-105.0**	**-211.3**	**-181.4**	**-240.8**	**-349.9**	**-637.8**
	Electric Utility Fuel purchases	**-0.7**	**-81.5**	**-168.8**	**-139.0**	**-210.3**	**-316.4**	**-5996.6**
	Reduced NY Generator Profits (Price Suppression)	**-0.1**	**-12.3**	**-16.2**	**-0.1**	**0.0**	**0.0**	**-183.8**
	Reduced Distribution System Expansion	**-2.4**	**-31.5**	**-81.0**	**-77.0**	**-56.7**	**-3.2**	**-1756.3**

6.8.3 Scenario Results

Table 50 presents aggregate total macroeconomic impacts (as differences and as percent change from the New York reference case)

Table 50. Aggregate Impacts of the Low PV Cost Scenario

Differences from Baseline Level								
Variable	**Units**	**2013**	**2019**	**2025**	**2030**	**2040**	**2049**	**NPV**
Total Employment	(Jobs)	1440	2462	2840	-566	-35	-239	N/A
Gross State Product	Billions of 2011$	0.147	0.302	0.422	-0.017	0.047	-0.003	2.717
Output	Billions of 2011$	0.079	0.282	0.444	0.042	0.071	-0.015	2.784
PCE-Price Index	2005=100 (Nation)	0.043	0.059	0.064	0.013	0.019	0.026	N/A
Real Disposable Personal Income	Billions of 2011$	0.248	1.478	2.263	0.915	0.300	0.087	17.075
Population	People	0	760	1523	1090	617	484	N/A
Percent Change from Baseline Level								
Variable	Units	**2013**	**2019**	**2025**	**2030**	**2040**	**2049**	
Total Employment	%	0.013	0.020	0.022	-0.004	0.000	-0.002	N/A
Gross State Product	%	0.010	0.017	0.020	-0.001	0.002	0.000	N/A
Output	%	0.008	0.013	0.016	-0.001	0.002	0.000	N/A
PCE-Price Index	%	0.003	-0.002	-0.008	0.006	0.002	0.003	N/A
Real Disposable Personal Income	%	0.004	0.015	0.021	-0.007	-0.001	-0.002	N/A
Population	%	0.001	0.009	0.015	0.008	0.004	0.002	N/A

Annual macroeconomic impacts for the Low PV Cost case are positive for jobs and dollars of gross state product (GSP) through 2025. This is the result of a dramatically smaller burden from the net solar subsidy cost to ratepayers (compared to the Base PV Scenario) despite solar investment demand that is 70% of the Base PV Scenario investment (see Decomposed Employment & GSP Impacts of the Low PV Cost Scenario). Apart from these two differences, the results are driven by the same policy effects from the Base PV Scenario. After 2025, the MW targets have been met and the investment demand stimulus ends along with the savings on RPS compliance costs. Other policy elements are responsible for exerting a more pronounced net negative effect through 2049. Those elements include negative ratepayer effects, from the net cost of the PV policy, reduced investment in generating capacity for New York, reduced upgrade and expansion of the distribution system, reduced purchases for biomass fuel and other variable operating expenses when existing generators operate at lower levels. Also, by 2039 the price suppression benefit for ratepayers expires. Over the entire analysis interval, the average annual job impact is a gain of approximately, 700 jobs, and the NPV of the cumulative GSP impacts (at a discount rate of 5.1 percent) is an increase of approximately $3 billion. The GSP impacts range from minus one-thousandth of one percent to a gain of two hundredths of 1 percent – very small in the scale of the NY economy.

The impacts on employment and gross state product (GSP) are decomposed by scenario direct effect (Table 51) to provide a better understanding of how the mix of stimulative and depressive elements alters employment and GSP. The pattern of resulting impacts for the stimulative elements of the Low PV Cost case is identical to the Base PV Scenario but for the amount of PV investment (all other direct elements are the same). Up through 2021 the PV investment activity will be responsible for the largest of the total job impacts, after which, the price suppression benefits to ratepayers will do so. While the price suppression benefit continues through 2039, it tapers dramatically starting in 2029, and the loss of the largest ratepayer benefit cuts into energy consumers' budgets and there begin to be total job losses. Similarly, for the expiration of avoided RPS compliance costs after 2025 jobs will be forfeited starting around 2027. Both avoided distribution system investment costs (the remaining ratepayer benefit) and persistent PV O&M spending will exert modest but continual positive annual impacts on jobs and dollars of GSP.

Among the negative elements associated with the Low PV Cost Case (and all cases), the cost of the policy (i.e. the net solar subsidy cost) on ratepayers is the most pronounced of all depressive effects extending well through the 37 year interval. It however will exert the smallest burden across all the PV cases and is the reason this single case produces positive (i) average annual job changes over the entire interval, and (ii) cumulative and NPV GSP impacts. All other depressive influences working on the NY economy are the same as under the Base PV Scenario.

Table 51. Decomposed Employment & GSP Impacts of the Low PV Cost Scenario

Total Employment (Annual Job Impacts)	2013	2019	2025	2030	2040	2049	Avg. Annual Impact
Investment PV (installation & soft costs)	1715	2180	2336	-197	92	87	735
Investment NY Manufactured content	101	97	82	-16	-8	-11	25
Electricity Price Suppression all ratepayers	16	2058	2613	194	-154	-135	733
Avoided RPS payments (ratepayers)	25	107	96	-5	-11	-9	29
Avoided Ratepayer Payments for Distribution Expansion	17	231	588	556	317	-45	311
Increased Demand from PV O&M spending	22	217	524	445	318	27	293
Reduced Purchase of Other variable O&M	-1	-103	-116	-69	-40	-59	-64
Increased Electric rates due to solar subsidy	-222	-1772	-1884	-1105	-124	200	-809
Decreased GEN Capacity Investments	-223	-122	-857	97	-16	-14	-154
Decreased Fuel Feedstock Purchases	-2	-280	-268	-234	-267	-277	-252
Reduced Distribution System Expansion	-8	-104	-228	-246	-144	-1	-139
Reduced Profits NY Generators (Price suppression)	0	-47	-47	15	0	-4	-15
Total	**1440**	**2462**	**2840**	**-566**	**-35**	**-239**	**692**
GSP (billion 2011$)	**2013**	**2019**	**2025**	**2030**	**2040**	**2049**	**NPV**
Investment PV (installation & soft costs)	0.171	0.215	0.222	-0.056	0.002	0.006	1.709
Investment NY Manufactured content	0.014	0.018	0.017	-0.002	0.000	-0.001	0.148
Electricity Price Suppression all ratepayers	0.002	0.348	0.551	0.205	0.074	0.031	3.884
Avoided RPS payments (ratepayers)	0.003	0.020	0.022	0.006	0.002	0.001	0.182
Avoided Ratepayer Payments for Distribution Expansion	0.002	0.037	0.113	0.133	0.115	0.033	1.179
Increased Demand from PV O&M spending	0.002	0.019	0.046	0.038	0.026	-0.005	0.382
Reduced Purchase of Other variable O&M	0.000	-0.020	-0.025	-0.015	-0.010	-0.020	-0.243
Increased Electric rates due to solar subsidy	-0.026	-0.302	-0.415	-0.331	-0.148	-0.040	-3.944
Decreased GEN Capacity Investments	-0.019	-0.010	-0.079	0.021	0.001	-0.001	-0.293
Decreased Fuel Feedstock Purchases	0.000	-0.009	-0.007	-0.004	-0.007	-0.013	-0.113
Reduced Distribution System Expansion	0.000	-0.008	-0.018	-0.016	-0.007	0.006	-0.147
Reduced Profits NY Generators (Price suppression)	0.000	-0.005	-0.004	0.004	0.001	-0.001	-0.026
Total	0.147	0.302	0.422	-0.017	0.047	-0.003	2.717

6.9. *High PV Cost Deployment Scenario – Inputs & Results*

6.9.1 Scenario Characteristics

This sensitivity case varies from the Base PV Scenario by the PV costs, it utilizes the installed costs, O&M costs and the LCOEs from the High PV Cost Future case described in Chapter 3.

6.9.2 Scenario Inputs

The information shown in Table 52 and Table 53 was derived in the course of the solar premium modeling analysis described in Chapter 5, and incorporates IPM model results described therein.

Table 52. High PV Cost Scenario Positive Effects, Select Years and Cumulative through 2049 (M 2011$)

	Direct Effect	2013	2019	2025	2030	2040	2049	Cumulative
STIMULATIVE	New Investment **Demand** PV	**621.4**	**1301.4**	**1481.2**	**0.0**	**0.0**	**0.0**	**15680.9**
	New O&M spending	**2.7**	**43.7**	**139.2**	**159.1**	**182.5**	**31.3**	**2358.8**
	Electric Price Suppression for ratepayers	**-2.1**	**-261.5**	**-343.7**	**-3.1**	**0.0**	**0.0**	**-3911.3**
	Residential	-0.7	-88.5	-116.3	-1.0	0.0	0.0	-1323.3
	Small C&I	-1.1	-135.0	-177.5	-1.6	0.0	0.0	-2018.0
	Large C&I	-0.3	-32.7	-43.0	-0.4	0.0	0.0	-491.5
	Government	0.0	-5.2	-6.9	-0.1	0.0	0.0	-78.5
	Avoided RPS Payments to ratepayers	**-3.7**	**-12.7**	**-12.1**	**0.0**	**0.0**	**0.0**	**-150.4**
	Residential	-1.3	-4.3	-4.1	0.0	0.0	0.0	-50.9
	Small C&I	-1.9	-6.6	-6.2	0.0	0.0	0.0	-77.6
	Large C&I	-0.5	-1.6	-1.5	0.0	0.0	0.0	-18.9
	Government	-0.1	-0.3	-0.2	0.0	0.0	0.0	-3.0
	Avoided Ratepayer Payments for Distribution Expansion	**-2.4**	**-31.5**	**-81.0**	**-77.0**	**-56.7**	**-3.2**	**-1756.3**
	Residential	-0.8	-10.7	-27.4	-26.1	-19.2	-1.1	-594.2
	Small C&I	-1.2	-16.4	-42.2	-40.2	-29.6	-1.7	-915.9
	Large C&I	-0.3	-3.8	-9.7	-9.3	-6.8	-0.4	-210.9
	Government	0.0	-0.6	-1.6	-1.5	-1.1	-0.1	-35.3

Table 53. High PV Cost Scenario Depressive Effects, Select Years and Cumulative through 2049 (M 2011$)

	Direct Effect	2013	2019	2025	2030	2040	2049	Cumulative
DEPRESSIVE	**Electric rate change (solar subsidy)**	**56.7**	**648.7**	**1302.6**	**1052.3**	**645.3**	**57.8**	**25422.2**
	Residential	19.2	219.5	440.7	356.0	218.3	19.5	8601.1
	Small C&I	29.6	338.3	679.3	548.8	336.5	30.1	13257.3
	Large C&I	6.8	77.9	156.5	126.4	77.5	6.9	3053.5
	Government	1.1	13.0	26.1	21.1	13.0	1.2	510.3
	Future Generating Capacity divestment	**-92.0**	**-43.1**	**-173.8**	**12.5**	**0.0**	**0.0**	**-1281.8**
	Electric Utility O&M purchases	**-3.7**	**-105.0**	**-211.3**	**-181.4**	**-240.8**	**-349.9**	**-637.8**
	Electric Utility Fuel purchases	**-0.7**	**-81.5**	**-168.8**	**-139.0**	**-210.3**	**-316.4**	**-5996.6**
	Reduced NY Generator Profits (Price Suppression)	**-0.1**	**-12.3**	**-16.2**	**-0.1**	**0.0**	**0.0**	**-183.8**
	Reduced Distribution System Expansion	**-2.4**	**-31.5**	**-81.0**	**-77.0**	**-56.7**	**-3.2**	**-1756.3**

6.9.3 Scenario Results

Table 54 presents aggregate total macroeconomic impacts (as differences and as percent change from the New York reference case)

Table 54. Aggregate Impacts of the High PV Cost Scenario

Differences from Baseline Level								
Variable	Units	2013	2019	2025	2030	2040	2049	NPV
Total Employment	(Jobs)	1697	917	-3415	-7034	-3146	168	N/A
Gross State Product	Billions of 2011$	0.171	-0.007	-0.862	-1.591	-1.142	-0.406	-10.025
Output	Billions of 2011$	0.223	-0.117	-1.507	-2.533	-1.793	-0.634	-16.782
PCE-Price Index	2005=100 (Nation)	0.006	0.037	0.088	0.099	0.072	0.023	N/A
Real Disposable Personal Income	Billions of 2011$	0.030	-0.218	-0.843	-1.165	-0.814	-0.289	-8.751
Population	People	232	232	-5279	-11457	-12234	-6174	N/A
Percent Change from Baseline Level								
Variable	Units	2013	2019	2025	2030	2040	2049	
Total Employment	%	0.000	0.007	-0.026	-0.051	-0.021	0.001	N/A
Gross State Product	%	0.012	0.000	-0.041	-0.069	-0.040	-0.012	N/A
Output	%	0.009	-0.004	-0.043	-0.066	-0.039	-0.012	N/A
PCE-Price Index	%	0.005	0.027	0.054	0.053	0.029	0.007	N/A
Real Disposable Personal Income	%	0.003	-0.020	-0.069	-0.086	-0.048	-0.014	N/A
Population	%	0.001	0.001	-0.023	-0.049	-0.048	-0.023	N/A

Annual macroeconomic impacts for the High PV cost deployment are positive for jobs through 2020 and for GSP through 2019. Of all the case presented thus far, this is the shortest interval of positive impacts on the NY economy. This is due to the magnitude and timing of the net PV subsidy cost being absorbed by ratepayers. So despite the fact that the High PV price case presents PV investment demand that is 28 percent larger than under the Base PV Scenario, the net PV subsidy is 85 percent larger as well (see Table 38 and Table 39). Apart from these two differences, the results are driven by the same policy effects from the Base PV Scenario. After 2025, the MW targets have been met and the investment demand stimulus ends along with the savings on RPS compliance costs. Other policy elements are responsible for exerting a more pronounced net negative effect through 2049. Those elements include negative ratepayer effects from the net cost of the PV policy, reduced investment in generating capacity for New York, and reduced purchases for biomass fuel and other variable operating expenses when existing generators operate at lower levels. Also, by 2039 the price suppression benefit for ratepayers expires. In the context of the entire analysis interval, the NY economy will see an average annual loss of approximately 2,500 jobs, and a GSP decrease (at a real discount rate of 5.1 percent) of approximately $10 billion.

The impacts on employment and GSP are decomposed by scenario effect (Table 55) to provide a better understanding of how the mix of stimulative and depressive elements alter employment and GSP. Similar to discussion of Low PV price, the High PV price case results will only differ from the PV Scenario case in (a) the amount of PV investment, and (b) the net cost of the PV subsidy to ratepayers. Among the positive elements for this case the solar investment sustains the largest source of positive job impacts through 2025 (when MW targets are satisfied). After that, price suppression benefits to ratepayers provide the largest stimulus to the economy in terms of jobs. The price suppression benefits will, however, starting in 2021, create the largest of the positive GSP impacts due to the composition of the ratepayer pool (many Commercial and Industrial activities within NY gain a competitive footing with lower rates). Though the price suppression benefit extends through 2039, the direct benefit tapers dramatically starting in 2029. This combined with the expiration of avoided RPS compliance costs after 2025 jobs will lead to job losses as the depressive elements of the PV case persist.

Among the negative elements associated with the High PV Cost case (as will be with all cases), the cost of the policy (i.e. the net PV subsidy cost) on ratepayers is the most pronounced of all negative effects extending well through the 37 year interval. The lost investment demand for new generating capacity (through 2030 as identified by the IPM model), and deferred upgrades and expansion of the distribution system also causes the NY economy to shed jobs and dollars of GSP.

Table 55. Decomposed Employment & GSP Impacts of the High PV Cost Scenario

Total Employment (Annual Job Impacts)	2013	2019	2025	2030	2040	2049	Avg. Annual Impact
Investment PV (installation & soft costs)	2105	3478	3479	-320	125	115	1102
Investment NY Manufactured content	121	183	171	-22	-3	-3	52
Electricity Price Suppression all ratepayers	16	2058	2613	194	-154	-135	733
Avoided RPS payments (ratepayers)	25	107	96	-5	-11	-9	29
Avoided Ratepayer Payments for Distribution Expansion	17	231	588	556	317	-45	311
Increased Demand from PV O&M spending	22	217	524	445	318	27	293
Reduced Purchase of Other variable O&M	-1	-103	-116	-69	-40	-59	-64
Increased Electric rates due to solar subsidy	-376	-4701	-9370	-7443	-3273	571	-4414
Decreased GEN Capacity Investments	-223	-122	-857	97	-16	-14	-154
Reduced Fuel Feedstock Purchase (Biomass, Coal, Oil/Gas)	-2	-280	-268	-234	-267	-277	-252
Reduced Distribution System Expansion	-8	-104	-228	-246	-144	-1	-139
Reduced Profits NY Generators (Price suppression)	0	-47	-47	15	0	-4	-15
Total	**1697**	**917**	**-3415**	**-7034**	**-3146**	**168**	**-2519**
GSP (billion 2011$)	**2013**	**2019**	**2025**	**2030**	**2040**	**2049**	**NPV**
Investment PV (installation & soft costs)	0.209	0.360	0.358	-0.086	0.001	0.008	2.679
Investment NY Manufactured content	0.018	0.034	0.036	-0.003	0.000	0.000	0.264
Electricity Price Suppression all ratepayers	0.002	0.348	0.551	0.205	0.074	0.031	3.884
Avoided RPS payments (ratepayers)	0.003	0.020	0.022	0.006	0.002	0.001	0.182
Avoided Ratepayer Payments for Distribution Expansion	0.002	0.037	0.113	0.133	0.115	0.033	1.179
Increased Demand from PV O&M spending	0.002	0.019	0.046	0.038	0.026	-0.005	0.382
Reduced Purchase of Other variable O&M	0.000	-0.020	-0.025	-0.015	-0.010	-0.020	-0.243
Increased Electric rates due to solar subsidy	-0.045	-0.771	-1.854	-1.872	-1.338	-0.446	-17.771
Decreased GEN Capacity Investments	-0.019	-0.010	-0.079	0.021	0.001	-0.001	-0.293
Reduced Fuel Feedstock Purchase (Biomass, Coal, Oil/Gas)	0.000	-0.009	-0.007	-0.004	-0.007	-0.013	-0.113
Reduced Distribution System Expansion	0.000	-0.008	-0.018	-0.016	-0.007	0.006	-0.147
Reduced Profits NY Generators (Price suppression)	0.000	-0.005	-0.004	0.004	0.001	-0.001	-0.026
Total	0.171	-0.007	-0.862	-1.591	-1.142	-0.406	-10.025

Figure 42 (total net job impact) and Figure 43 (total GSP impact) show how the three PV cost cases compare in affecting jobs and GSP for New York.

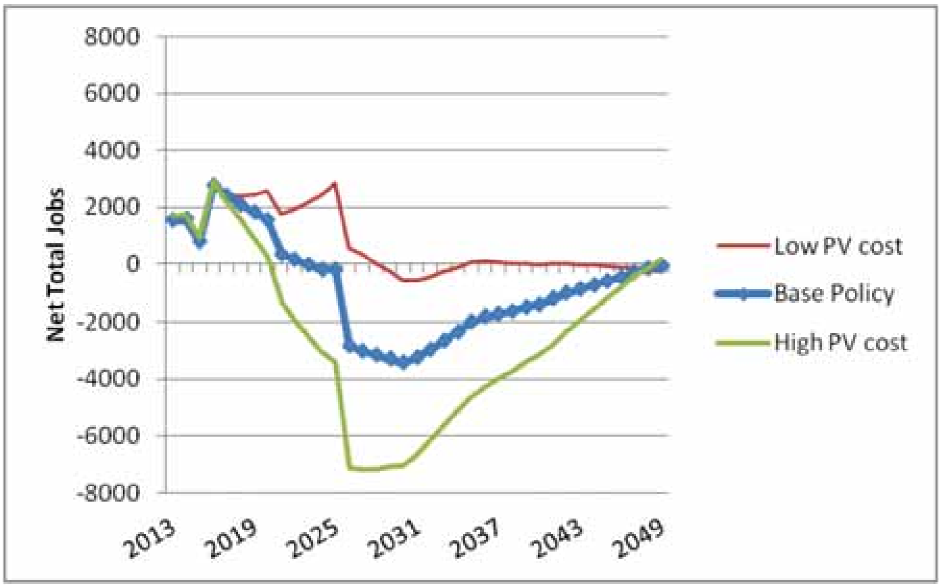

Figure 42. Net Total Job Impacts across PV Cost Cases

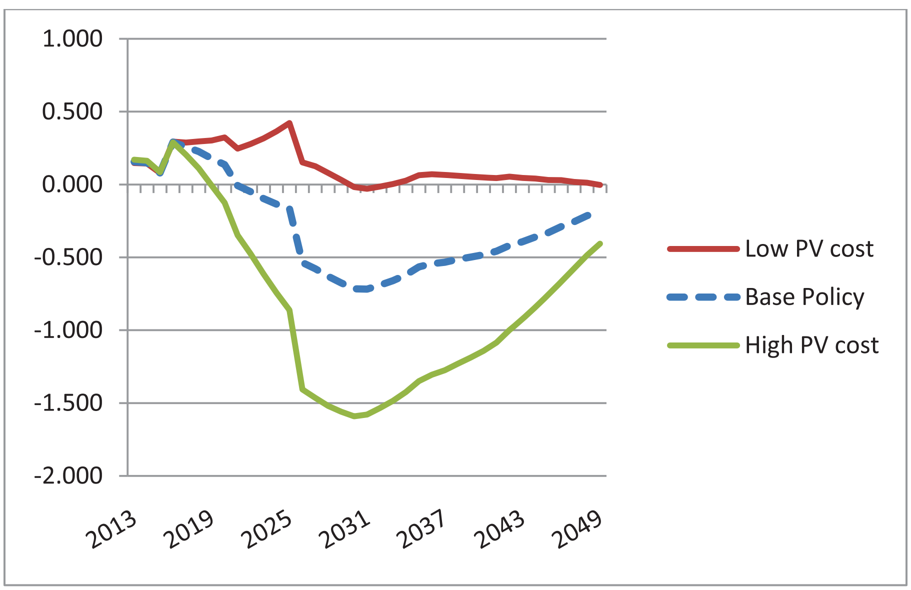

Figure 43. Total GSP Impacts across PV Cost Cases (Bil 2011$)

6.10. Summary of Results

Focusing on the average annual impact for the 37 year interval for net total job impacts (in Table 56) the policy under low PV price environment will add approximately 700 jobs per year, the base policy will reduce jobs by 750 per year, and the high PV price case will reduce jobs by 2,500 per year. In terms of dollars of GSP impact (in Table 57), the cumulative NPV is an increase of almost $3 billion under low PV price, a reduction of almost $3 billion for the Base PV Scenario , and for the high PV price, a reduction of nearly $10 billion. Employment and GSP impacts segmented for different yearly intervals can be found in Appendix 7.

Table 56. PV Annual net Total Job Impacts

Scenario	2013	2019	2025	2030	2040	2049	Job-years	Avg. Annual
Base PV Scenario	1549	1821	-188	-3441	-1396	-43	-27653	-747
Low PV Cost Future	1440	2462	2840	-566	-35	-239	25615	692
High PV Cost Future	1697	917	-3415	-7034	-3146	168	-93197	-2519
New York reference case Employment (thous.)	11496	12453	13145	13683	14689	14943		
as % of reference case Employment								
Base PV Scenario	0.01%	0.01%	0.00%	-0.03%	-0.01%	0.00%		
Low PV Cost Future	0.01%	0.02%	0.02%	0.00%	0.00%	0.00%		
High PV Cost Future	0.01%	0.01%	-0.03%	-0.05%	-0.02%	0.00%		

Table 57. PV Annual $ of GSP Impacts (Bil 2011$)

Scenario	2013	2019	2025	2030	2040	2049	Cumulative	NPV
Base PV Scenario	0.16	0.18	-0.16	-0.72	-0.48	-0.19	-10.84	-2.93
Low PV Cost Future	0.15	0.30	0.42	-0.02	0.05	0.00	4.49	2.72
High PV Cost Future	0.17	-0.01	-0.86	-1.59	-1.14	-0.41	-29.94	-10.02
New York reference case GSP (Bil 2011$)	1424	1826	2084	2312	2840	3288		
as % of reference case GSP								
Base PV Scenario	0.01%	0.01%	-0.01%	-0.03%	-0.02%	-0.01%		
Low PV Cost Future	0.01%	0.02%	0.02%	0.00%	0.00%	0.00%		
High PV Cost Future	0.01%	0.00%	-0.04%	-0.07%	-0.04%	-0.01%		

7. RETAIL RATE IMPACTS

7.1. Introduction

This chapter presents calculations of the total impact of PV deployment on New York State ratepayers and electricity bills under both the Base PV Deployment and under a range of different alternative scenarios.

Key findings of this Chapter include:

- The Base PV Scenario's rate impact is expected to lead to less than a 1% increase in rates above the reference case over the entire study period, without taking into account electricity price suppression savings. Base PV Scenario results in approximately $3.4 billion in ratepayer impact over the entire study period (2013-2049)
- The net impact of the PV deployment on electricity bills takes into account the above- market costs of PV, the costs of net metering, and the savings generated by the suppression of wholesale electricity prices
- As with the cost benefit analysis, the cost of PV has the greatest impact causing rate impacts to range from close to zero for low PV cost assumptions to 2.4% over the entire study period for the high PV case
- The net impact of these factors on retail electricity rates is $3 billion over the study period, or approximately 0.9% of total electricity bills
- Analyses of low and high PV cost scenarios were also conducted. The net impact of the low PV cost scenario is approximately $300 million in additional ratepayer impacts or 0.1% of total bills, whereas the net impact under the high cost scenario would be $9 billion or 2.4% of total bills
- An analysis was also conducted to determine the effect of higher natural gas prices on PV impacts. Higher natural gas prices would reduce the above market cost of PV and lower the retail rate impact to 0.6% of total electricity bills instead of 0.9%
- Since retail rates are higher in downstate areas such as New York City and lower in upstate New York, PV is closest to grid parity downstate. Concentrating smaller-scale PV installations downstate would result in lower overall retail rate impacts (0.7% of total bills) whereas installing a greater amount of larger-scale PV systems upstate would increase overall retail rate impacts (1.4% of bills)
- The continued operation of Indian Point does not materially impact the PV policy ratepayer impact.

This chapter is organized as follows:

- Section 7.2 presents the direct rate impact calculated under the Base PV Scenario.

- Section 7.3 describes and calculates the impact of the cross subsidy from net metering.
- Section 7.4 presents the net rate impacts, taking into account both the net metering cross subsidy and the electricity price suppression impact.
- Sections 7.5 to 7.7 present the results of sensitivity analyses of the Base PV Scenario. Section 7.5 focuses on the cost of PV, Section 7.6 examines the impact of different geographic deployment scenarios, and Section7.7 analyzes the impact of high energy prices.
- Section 7.8 contains a summary of key results.
- Appendix 8 provides details on cost premium and rate impact calculation methodology, additional detail on rate impact results, as well as the sensitivity analysis of continued operation of Indian Point.

This chapter derives the cost premiums projected to be paid by ratepayers for a Base PV Scenario and the sensitivity analyses discussed in Chapter 5. The cost premium considers the 'above market' cost of PV incentives borne by ratepayers. It estimates the direct above-market cost to ratepayers of the PV policy by calculating the difference between the LCOE and the wholesale value of electricity generated by grid-connected solar projects and calculating the difference between the LCOE and the retail value of electricity generated by behind-the-meter solar projects. Based on these calculations, direct annual rate impacts are projected for the Base PV Scenario (policy option rate impacts are discussed in Chapter 10). This chapter also calculated net annual rate impacts by further including the wholesale price suppression impacts of solar and the net-metering cross-subsidy relating to a PV owner's avoided transmission and distribution components of retail rates associated with behind-the-meter generation.

7.2. Direct Rate Impact

Direct rate impacts are the "over market" incentive costs borne by ratepayers through the applicable collection mechanism (e.g. SBC charges, SREC charges passed on by electricity suppliers, etc.), including administrative costs.[91] Retail rate impact (as a percentage of bill) is calculated as the total policy costs divided by total annual expenditures in New York State. Thus, it is assumed for these purposes that the total costs of the policy options, regardless of different geographic deployment of solar resources, will be borne by all ratepayers in proportion to their total bill. Two statewide forecasts of total electricity expenditures were developed as the denominator for use in calculating the annual average retail rate impact percentage of the base policy and the different sensitivities—a separate forecast of revenues was applied to

91 Depending on the incentive mechanisms, administrative costs might be paid by ratepayers through the same collection mechanism as incentive costs (e.g. in central procurement, passed along together as part of a system benefit charge mechanism), or separately (e.g. under an SREC market mechanism where the policy incentive cost is embedded in retail generation service supply costs, while administrative costs may be collected through other means).

the high natural gas sensitivity—as a percentage of total bills. For the reference case, EIA's AEO 2011 reference forecast for the three New York regions — NYC/Westchester, Long Island, and Upstate — was used to calculate a weighted average total retail revenue (delivery and supply charges) for each year in the study period. For years after 2035 (the last year in the EIA forecast), the historical (2013-2035) compound average annual growth rate of 2.6% was applied in each year. For the high gas case, the IPM model results discussed earlier were used to adjust the reference forecast. Figure 44 below shows these two forecasts of total retail electricity expenditures in nominal dollars.

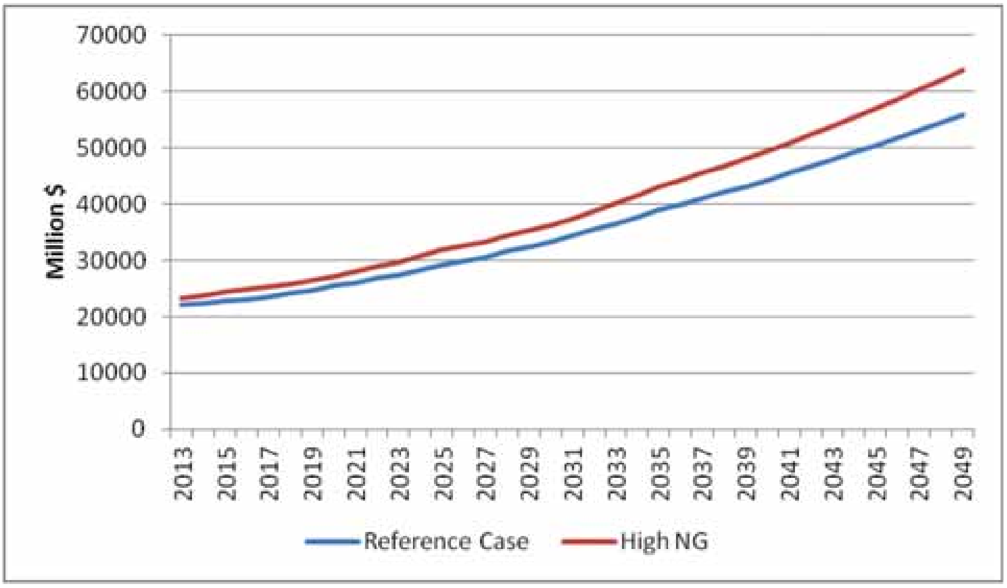

Figure 44. Total Electricity Expenditures, New York, 2013-2049 under Reference and High Gas Assumptions

The annual rate impact as a percentage of total bills is shown for the base policy in Figure 45. Percentage of bills are shown in nominal dollars and peak in 2025 in the last year of the deployment and decline thereafter as the deployment (in terms of energy production) becomes increasingly dominated by lower-priced solar facilities and total state revenues begin to accelerate.

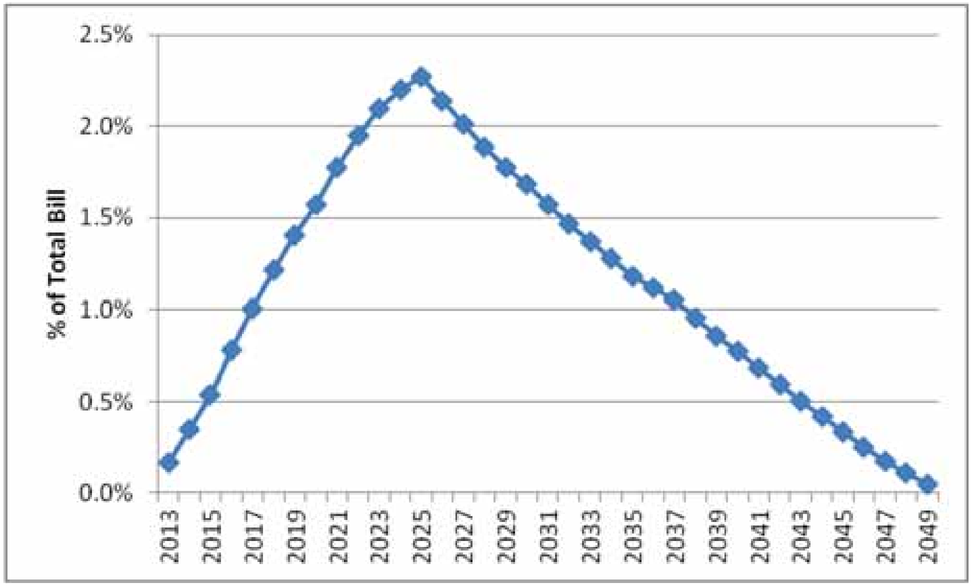

Figure 45. Percentage of Total Bill, Base PV Scenario, 2013-2049

7.3. Rate Impact of Net Metering

For PV production used behind the retail meter, either directly or financially under net metering or virtual net metering regulations, the retail premiums shown above account for avoided delivery charges. The avoidable portion of the distribution cost (excluding fixed billing determinants) that was formerly borne by the behind-the-meter PV system host must now be borne by other ratepayers, assuming revenue neutrality for the electric distribution companies. This cross-subsidy results from the ability of behind-the-meter PV generation, through policies such as net metering or virtual net metering, to displace a portion of transmission and distribution rates, the costs of which are ultimately expected to be allocated to other (non-participating) customers.

Figure 46 shows this transfer on an annual basis. The total amount of transfer peaks in 2038, which is the peak year for energy production and tapers off as projects begin to reach the end of their useful lives.

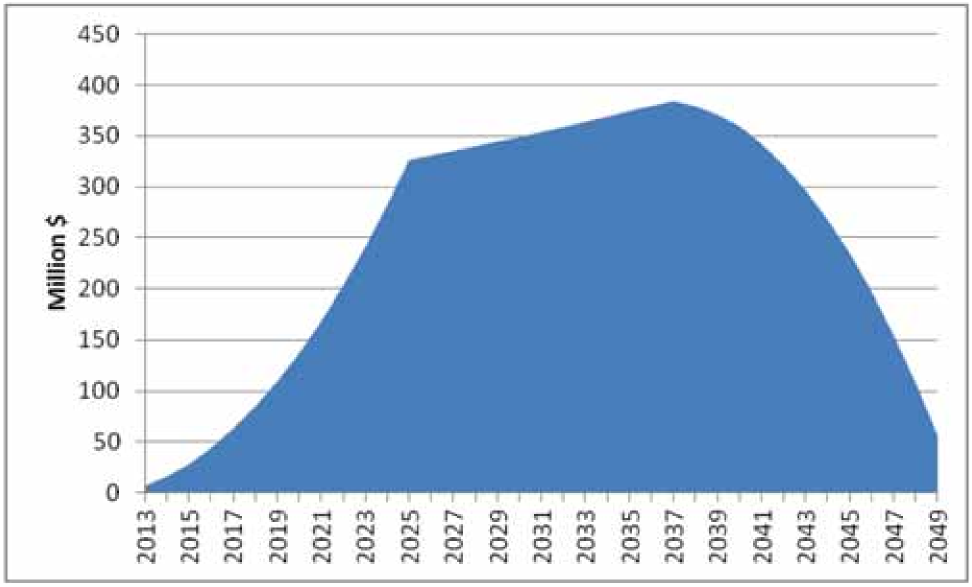

Figure 46. Net Metering Rate Impact, 2013-2049

7.4. Net Rate Impacts

The remainder of the results discussion in the chapter is in terms of "net" rate impacts. Net rate impacts are calculated by adjusting the direct rate impacts discussed previously. Specifically, net rate impacts = direct rate impacts + net metering rate impacts + wholesale price suppression impacts. This last term was discussed in Chapter 5 (see Figure 31). This net rate impact concept can be considered as an estimate of the ultimate cost responsibility that all New York ratepayers will eventually pay. Figure 47 shows the two components of the direct rate impact (wholesale and retail premium) and the two additional components used to calculate the net rate impact.[92] An examination of the wholesale and retail premiums shows the 2025 peak discussed above. Net rate impact, however, peaks in 2029 due to strong wholesale price suppression impacts in the years prior to 2029.

[92] The underlying data of this figure can be found in the appendix for this chapter.

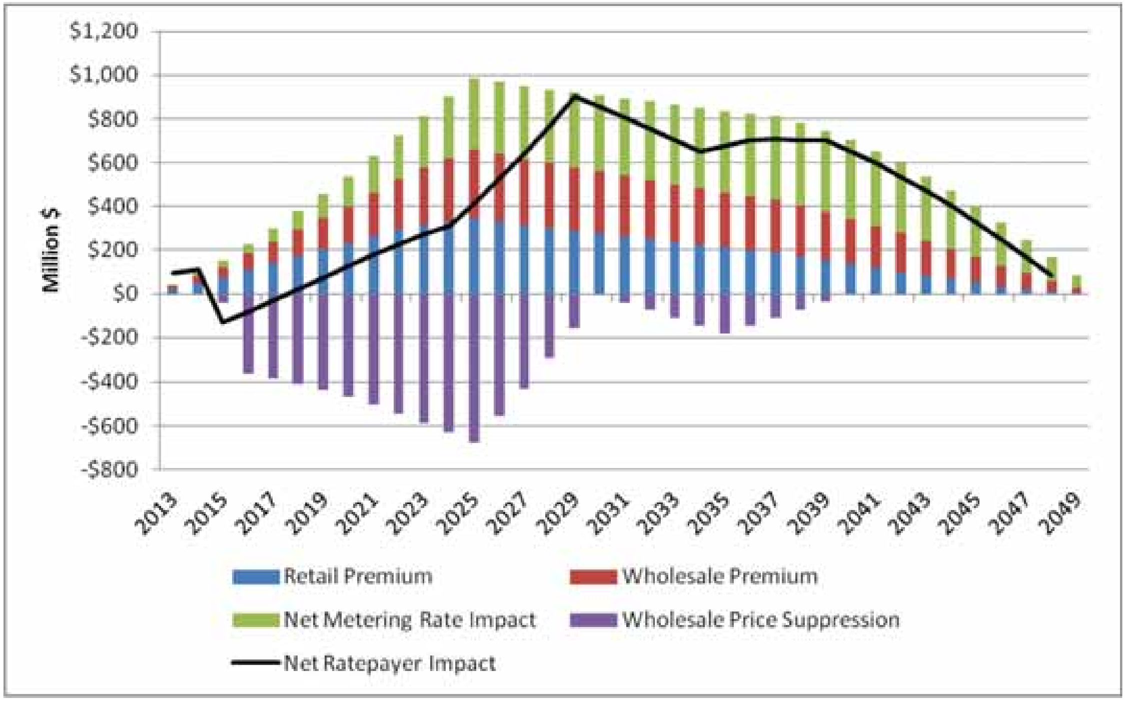

Figure 47. Net Rate Impact Components, Base PV Policy, 2013-2049 (nominal $)

Table 58 summarizes the net rate impacts of the base PV policy along with the various sensitivity cases, which are discussed in greater detail in the next section. As with the cost-benefit analysis, net rate impacts are most sensitive to the cost of PV with some sensitivity to the deployment (more urban results in lower rate impacts) and higher natural gas prices, which reduces the rate impacts as higher market revenues generated by higher natural gas prices reduce the need for ratepayer subsidy.

Table 58. NPV of Net Rate Impact, Base PV Policy Compared to Sensitivity Cases, 2011$

Case	Net Rate Impact (NPV Million 2011$)
Base PV Scenario	$3,382
Low PV Cost Sensitivity	$340
High PV Cost Sensitivity	$8,655
Alt-A Deployment Sensitivity	$2,433
Alt-B Deployment Sensitivity	$5,017
High NG Sensitivity	$2,379
Indian Point Sensitivity	$3,364

7.5. Sensitivity Analyses: Cost of PV

Figure 48 shows the net rate impact of the base policy under base, low, and high PV capital costs. Not surprisingly, the overall results are most sensitive to the cost trajectory of solar installations. IPM modeling results are assumed to be identical for all three cost cases. Direct rate impacts peak in 2025 and decline thereafter as the solar mix becomes increasingly dominated by lower-cost solar installs as earlier installs degrade and reach the end of their useful lives.

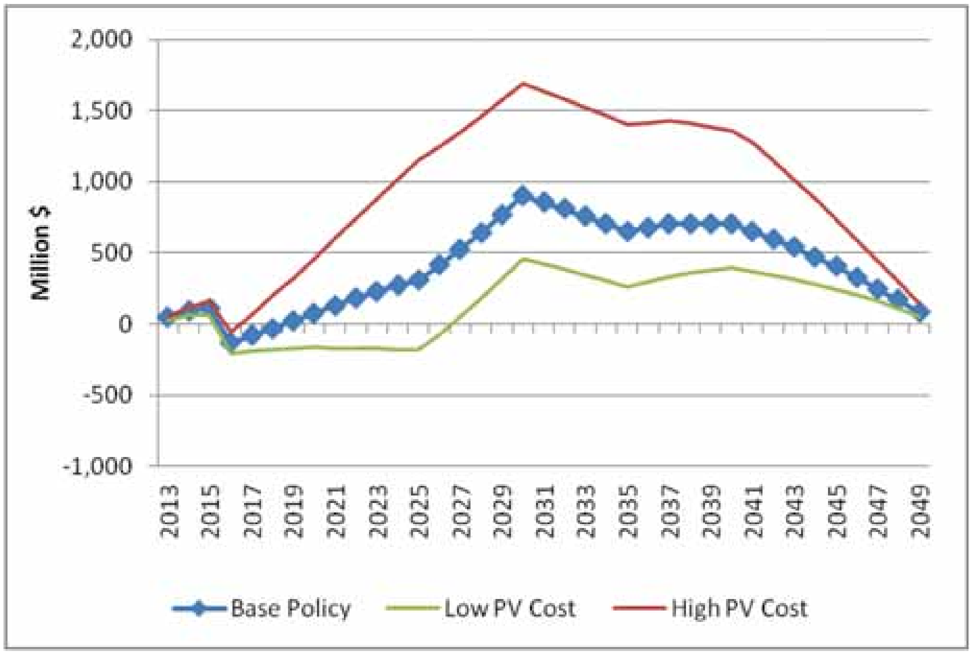

Figure 48. Net Rate Impact, Base, Low and High PV Cost, 2013-2049

7.6. Sensitivity Analyses: Alternative Deployment Scenarios

Figure 49 shows the sensitivity of the net rate impact results to alternative deployment scenarios. The figure shows that rate impacts are highest for the Alt-B deployment. As discussed in Chapter 4, the Alt-B deployment features more rural, larger scale deployments. Rate impacts are highest for this deployment due to lower retail avoided costs in rural than in urban areas, which have the highest retail electricity rates in the state. This impact of less displacement of higher retail rates offsets the lower capital costs in rural areas and for larger-scale installations that were assumed and discussed in Chapter 3.

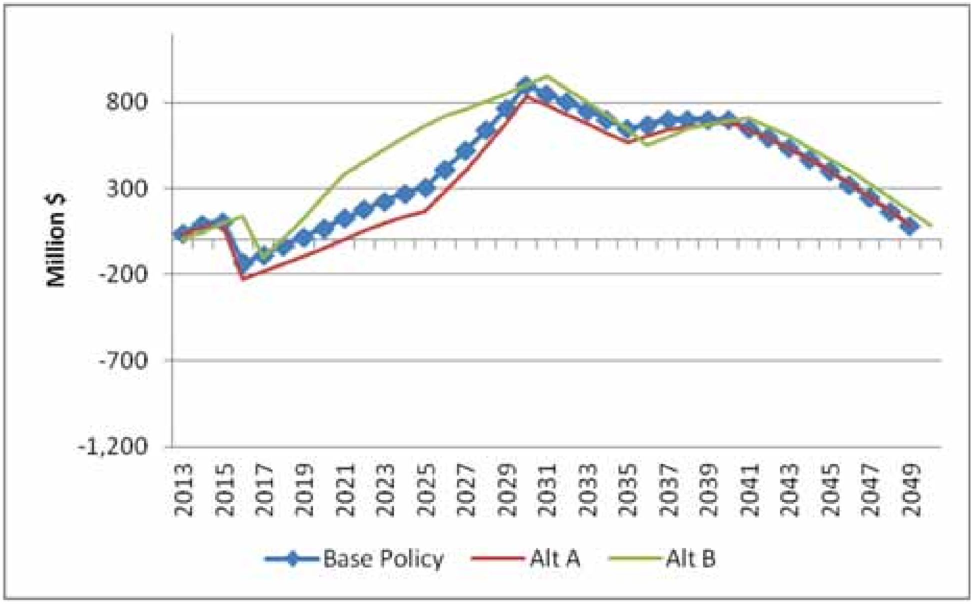

Figure 49. Net Rate Impact, Base, Alt-A, Alt-B, 2013-2049

7.7. Sensitivity Analysis: High Energy Prices

Figure 50 shows the sensitivity analysis under high natural gas prices. Higher energy prices should, holding other things constant, increase potential market revenues to solar projects. The figure does show that as solar increases its deployment through 2025, the impact of higher natural gas price impacts serves to increase market revenues and hence reduces the retail rate impact. This impact remains relatively constant through the 2038 year, which is the last year of the useful life of the first solar deployment (in 2013). As solar facilities "retire" the impact of higher natural gas prices is mitigated and eventually come close to disappearing in the final year of the study period.

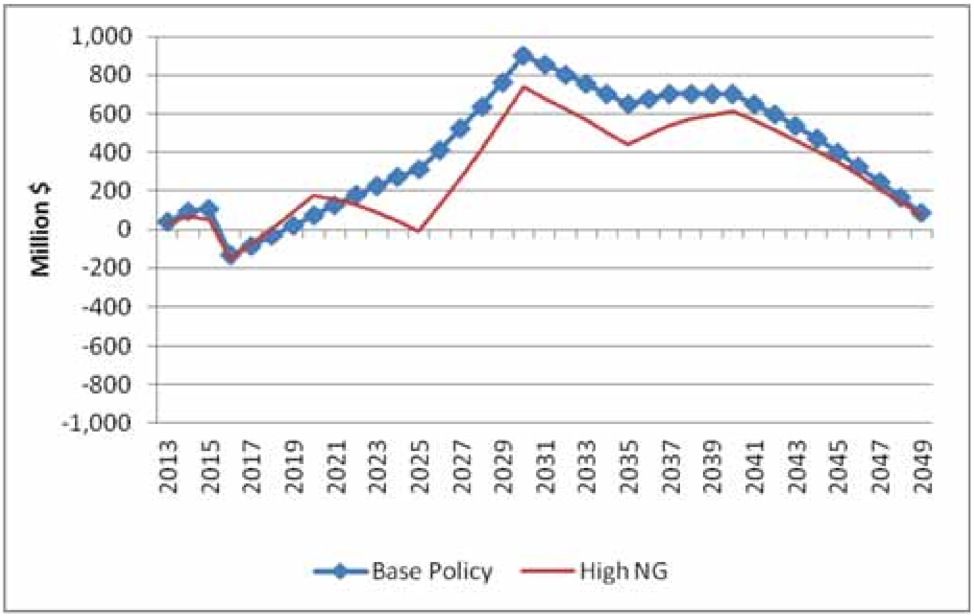

Figure 50. Net Rate Impact, Base, High NG, 2013-2049

7.8. Summary of Key Results

In terms of net ratepayer impact, Table 59[93] shows that the base policy results in approximately $3.4 billion in ratepayer impact over the entire study period with most of that rate impact occurring in years 11 through 20. Rate impacts are relatively small towards the end of the study period as earlier installed, more expensive solar installations are retired and avoided costs continue to rise (while PV costs fall). Not surprisingly, net rate impact sensitivities follow a similar pattern to the cost-benefit sensitivities with strong sensitivity to the costs of PV, some sensitivity to deployment and gas prices, and almost no sensitivity to the continued operation of Indian Point.[94]

93 Additional results for different discount rates for both tables in this section can be found in this chapter's appendix.

94 Results of the sensitivity analysis on Indian Point continued operation are found in Appendix 8.

Table 59. Net Rate Impact, Base Policy and Sensitivities 2013-2049

Case	Net Rate Impact (NPV)		Maximum Annual Net Rate Impact
	(Million 2011$)	(% of Total Bill)	(% of Total Bill)
Base PV Scenario	$3,400	1%	3%
Low PV Cost Sensitivity	$340	0.1%	1.%
High PV Cost Sensitivity	$8,700	2%	5.%
Alt-A Deployment Sensitivity	$2,400	0.7%	3%
Alt-B Deployment Sensitivity	$5,000	1.4%	3%
High NG Sensitivity	$2,400	0.6%	2%
Indian Point Sensitivity	$3,400	0.9%	3%

Table 59 also shows that over the entire period, the Base PV Scenario's rate impact is expected to lead to less than a 1% increase in rates above the reference case over the entire study period. This impact can be further reduced by deploying a strategy that targets more congested, urban areas as shown in the Alt-A results. As with the cost benefit analysis, the cost of PV has the greatest impact causing rate impacts to range from close to zero for low PV cost assumptions to 2.4% over the entire study period for the high PV case. The corresponding results tables in Appendix 8 show, the rate impacts are concentrated in the beginning of the second half of the study period, mostly due to the disappearance of wholesale price suppression impacts after 2030.

8. ENVIRONMENTAL IMPACTS

8.1. Introduction

This chapter explores the environmental impacts of PV deployment in greater detail. Whereas Chapter 5 included carbon dioxide reductions in the consideration of costs and benefits, this chapter takes the value of additional air pollutants such as sulfur dioxide, nitrogen oxides, and mercury into account. The Chapter also explores the potential land use impacts of PV.

Key findings of this Chapter include:

- Over the study period (2011 – 2049) PV will reduce fossil fuel by 1,100 trillion Btus (TBtus). This includes a 7% reduction in the use of natural gas, a 4% reduction in the use of coal, and a 40% reduction in the use of oil in the electricity sector in 2025.
- This reduction will lower CO_2 emissions by 47 million tons, equivalent to taking an average of approximately 250,000 cars off of the road for each year of the study period. The CO_2 emissions reductions are valued at between $450 million and $3.2 billion.
- A high valuation for CO_2 emission reductions has a significant enough impact to make the Base PV Scenario net-beneficial to NY.
- The amount of CO_2 reductions remains small compared to the total reductions that were identified for the power generation sector in the New York Climate Action Plan Interim Report. In 2025, PV will reduce emissions by 1.7 million metric tons, or 5% of the emissions from the electric generation sector in that year .
- The reduction in fossil fuel use will lower NO_x by 33,000 tons, SO_2 by 67,000 tons and mercury by 120 pounds. The net present value of these combined reductions is approximately $130 million over the study period. This valuation is based on health benefits only, and does not attempt to monetize ecosystem benefits (such as reductions in acidification of lakes, streams and forests, and eutrophication of estuaries and coastal waters). In 2025, PV will reduce total NO_x emissions by 4%, total SO_2 emissions by 17% and total mercury emissions by 6%.
- PV could also require land to site systems. It estimated that 5,000 MW of PV would require 23,000 acres of land if the entire amount was ground-mounted. Nevertheless, there is a significant amount of roof space available, as well as areas such as brownfield sites, existing power plant sites, and parking lots, where PV could be deployed without using land that could have other productive uses. In total, it is estimated that PV would require from 2,600 – 6,000 acres of green field space total, which is less than 0.02% of total state land area.

This chapter is organized as follows:

- Section 8.2 provides an overview of environmental impacts of energy generation.

- Section 8.3 presents the methodology utilized for analyzing air pollution impacts.
- Section 8.4 describes the amount of fossil fuel consumption reduced as a result of PV deployment.
- Section 8.5 analyzes the total amount and value of the carbon dioxide emissions reductions that result from PV deployment.
- Section 8.6 analyzes the total amount and value of the sulfur dioxide, nitrogen oxide, and mercury emissions that result from PV deployment.
- Section 8.7 analyzes the change in emission reductions associated with deploying PV in more urban and more rural areas.
- Section 8.8 describes the land use impacts associated with deploying PV, including a comparison of deployment in more urban and more rural areas.

8.2. Environmental Impacts

The installation of 5,000 MW of PV in New York will positively impact the environment by reducing use of fossil fuels for electricity generation. Fossil fuels create environmental burdens at every stage of their fuel cycle, from ecosystem and human health impacts associated with the extraction process, to air and water pollution from plant operation, to disposal issues associated with toxic waste products. By reducing the need for fossil fuel power plants, PV will reduce these negative impacts. PV also impacts another important environmental consideration of PV is the land area used to install systems.

Today nearly all PV installations in the Northeast are installed on roof tops or other structures. It is likely that the number of ground-mounted systems will increase, however, as New York scales up its PV market and looks to build systems that are too large for roof tops. The use of green field sites by PV installations is a potentially negative impact on the environment

8.3. Methodology for Analyzing Air Pollution Impacts

The electricity generation sector is a major source of emissions of several air pollutants that impact the environment and public health .These include carbon dioxide (CO_2), which contributes to global climate change, sulfur dioxide (SO_2) which contributes to acid rain and fine particle concentrations in the atmosphere (causing asthma and other health problems), nitrogen oxides (NO_x) which contribute to both of these pollution problems and to ground-level ozone (a lung irritant that also damages trees and crops), and mercury, which is a toxic substance linked to neurological and other health problems. This report focuses on the value of the reduced air pollutants achieved by this reduction in fossil fuel use, as attempting to quantify the full range of environmental benefits is beyond the scope of this project.

The IPM model was used to project the total amount of air emissions reductions in New York that result from the deployment of PV resources across the state. The emissions analyzed include NO_x, SO_2, mercury and CO_2. Utilizing the IPM model allows the effects on emissions to be evaluated on a marginal basis. This is the ideal method as it identifies the specific marginal resources that are affected by the deployment of PV across New York and calculates the impact to their emissions. In IPM, the RGGI program is modeled as a hard emission cap with allowance trading. IPM solves for the allowance price needed to meet the cap, but with a floor price equal to the floor price specified for the RGGI auction. The allowance price flows through the market solution to outputs such as energy prices and investment decisions.

The impact on emissions is calculated by comparing the total emissions from New York resources in the relevant reference case to total emissions from New York resources in each of the deployment scenarios modeled.

The net present value of the reductions in the amount of each air pollutant was calculated for the entire study period. The $/ton reduction values for NO_x, SO_2 and mercury were drawn from previous research efforts:

- Monetary Benefits of a reduction on NO_x and SO_2 were calculated using the method developed in "Efficient Emission Fees in the US Electricity Sector" by Resources for the Future **(Banzhaf, Burtraw, & Palmer, 2002)**. In this paper, $/ton values (1999$) are developed for SO_2 and NO_X ($3,500/ton, and $1,100/ton respectively) based on the changes in health status expected to occur due to changes in pollutant concentrations. Health status changes include the number of chronic disease cases, the number of days of acute morbidity effects, and the number of statistical lives lost. Monetary values, including a statistical life value of 2.25 million 1999$, are applied to these health effects to generate the final $/ton values
- Monetary Benefits of a reduction in mercury (Hg) were calculated using the method developed in "Economic Valuation of Human Health Benefits of Controlling Mercury Emissions from U.S. Coal-Fired Power Plants" by members of Northeast States for Coordinated Air Use Management **(Rice, Hammitt, & Amar, 2005)**. In this paper, a value of $194.5 million/ton of mercury reduced (2000$) is developed based on the change in health effects from human exposure to methylmercury through fish consumption, the primary pathway of human exposure, due to decreased mercury concentrations in fish. A cost-of-illness approach is used to value both cardiovascular illness, and decreased cognitive abilities, with values of $16,500 (2000$) per IQ point lost, and $6 million (2000$) per premature fatality used to generate the final $/ton value.

For all three pollutants, these monetary values are based on health benefits only, and do not attempt to monetize ecosystem benefits (such as reductions in acidification of lakes, streams and forests, and eutrophication of estuaries and coastal waters) or aesthetic impacts (such as visibility improvements in natural parks and wildlife viewing areas).

The $/ton reduction value from CO_2 is uncertain and so two separate values were utilized to represent the potential range. CO_2, was valued at $15/ton in the cost and benefit analysis in Chapter 5. This is the current value used by NY DPS as part of electricity generation sector benefit-cost tests. For the higher boundary, a value of $107/ton was used for the analysis in this chapter. The higher value uses an assumption of $107/ton which was developed for the UK government as part of the Stern Review on the Economics of Climate Change and reflects the net cost to society from climate change (a damage function approach) such as lost ecosystem services (Stern Review, 2006).

8.4. Fossil Fuel Consumption Reductions

The total amount of fossil fuel consumed during the study period for electricity generation was calculated and used to estimate the amount of fossil fuel consumption avoided with 5,000 MW of PV. In total, the base PV scenario would reduce fossil fuel consumption in power plants by 1,100 trillion Btus (TBtus). Table 60 below lists the total amount of coal, natural gas, and oil that is projected by the IPM model to be consumed in 2025 and as well as the projected reduction in consumption resulting from PV installations. A more detailed summary of changes in fuel consumption over time is included in Appendix 11.

Table 60. Projected Reductions in Fossil Fuel Consumption from PV Generation in 2025

Fuel type	Amount consumed in 2025 (TBtus)	Fuel displaced by PV in 2025 (TBtus)	% reduction in fuel consumption in 2025
Coal	110	8	7%
Natural gas	460	20	4%
Oil	2	0.80	38%

8.5. Carbon Dioxide Emissions Reductions

Over the course of the study period, it is projected that PV would displace a total of 47 million tons of carbon dioxide. Applying both the lower bounds and upper bounds assumptions for the value of carbon dioxide reductions, the net present value of these reductions would be between $450 million and $3.2 billion. The difference between these two values is significant. The lower value was already used in the benefit-cost analysis in Chapter 5. Using the higher value instead would markedly improve the benefit-cost analysis in favor of PV deployment; the impact of PV deployment would change from a loss of $2.2 billion in the base case to a gain of $590 million. Year-by-year calculations of the value of carbon dioxide reductions for both the low and high value cases is included in Appendix 11.

Based on the electricity system modeling conducted as part of this study, the total CO_2 emissions from the New York electric generation sector will be approximately 34 million metric tons in 2025. The deployment modeled in this study will achieve 1.7 million metric tons of reductions in that year, or roughly 5% of the total projected emissions. The installation of 5,000 MW of PV will therefore contribute to the state's overall goals to reduce carbon dioxide emissions in the electric power sector, but a broader portfolio of climate action strategies will be required if the state seeks to achieve an 80 by 50 greenhouse gas emission reduction goal, as had been identified in the New York State Climate Action Plan Interim Report [95].

8.6. Sulfur Dioxide, Nitrogen Oxides, and Mercury Emissions Reductions

The total amount of sulfur dioxide, nitrogen oxides and mercury emissions that PV would displace over the course of the study period is contained in Table 61 below. The table also contains the total value of each of the emissions reductions using the values for SO_2, NO_X, and mercury described in Section 8.3 above.

Table 61. Total SO_2, NO_X, and Mercury Emissions Reductions and NPV (2013-2049)

Air Pollutant	Total amount	Net present value of emissions reductions (Million $2011)
SO_2 (tons)	67,000	$24
NO_x (tons)	33,000	$97
Mercury (pounds)	120	$13

The total value of these avoided emissions over the study period is approximately $130 million. Incorporating this value into the calculation of PV deployment's cost to society would reduce the total losses from $2.2 billion in the base PV scenario to approximately $2.1 billion. A comparison of the magnitude of value of the avoided emissions, including the lower value assumption for CO_2 is included in Figure 50a. The high value for CO_2 is not included since it is 1-2 orders of magnitude larger than the other values.

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95 Executive Order 24 in August 2009 formally established a State goal of reducing GHG emissions 80 percent below 1990 levels by 2050 (or 80 by 50), See the New York State Climate Action Plan Interim Report - November 9, 2010. http://nyclimatechange.us/

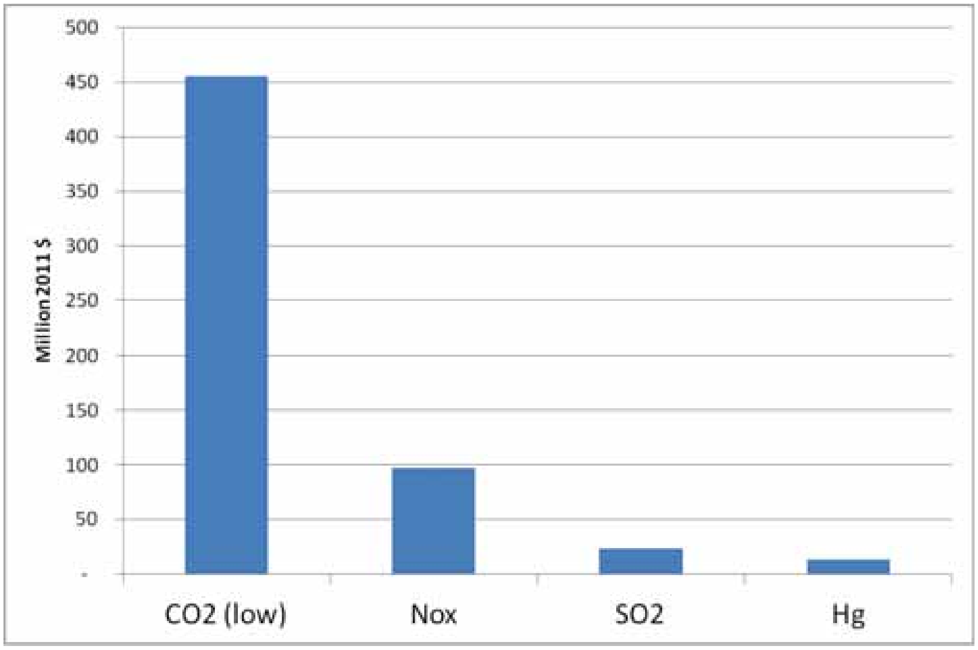

Figure 50a. NPV of SO_2, NO_X, Mercury, and CO_2 Emissions Reduced (2013-2049)

Table 62 below lists the total amount of NO_X, SO_2, and mercury emission projected for 2025 and the corresponding avoided emissions associated with PV deployment. PV deployment will have the greatest impact on the total amount of SO_2 emissions. A more detailed summary of changes in air emissions over time is included in Appendix 11.

Table 62. Projected SO_2, NO_X, and Mercury Emissions Reduced by PV Generation, 2025

Fuel type	Emissions in 2025 (tons)	Emissions reduced by PV in 2025 (tons)	% reduction in fuel emissions in 2025
NO_X	24	0.9	4%
SO_2	15	2.5	16%
Mercury	0.04	0.002	6%

8.7. Emissions Reductions for Alt-A and Alt-B Deployments

Avoided emissions projected under the Base PV Scenario were also compared to projections that assumed that PV was concentrated more in urban areas (Alt-A) or rural areas (Alt-B). Table 63 shows that although avoided GHG and NO_x impacts are similar across the three geographic scenarios, there are notable differences in SO_2 and mercury emissions, which are higher under Alt-B. These differences presumably reflect the specific emission characteristics of the existing plants that are displaced by the solar deployment for each deployment case.

Table 63. Environmental Impacts, Energy Costs under Alternative Deployment Scenarios

		Base PV Scenario	Alt-A Deployment	Alt-B Deployment
Criteria	**Metric (units)**	**2013-2049**	**2013-2049**	**2013-2049**
GHG Reduction	M Tons of CO_2	(46.8)	(42.5)	(48.1)
GHG Cost	(NPV M 2011$)	(507)	(492)	(519)
Criteria Pollution Reduction	Tons of SO_2	(67,361)	(42,016)	(77,468)
	Tons of NO_x	(33,452)	(28,637)	(32,864)
	Pounds of Mercury	(116)	(66)	(142)

8.8. Land Use Impacts

Nearly all PV installations in the northeast are installed on roof tops or structures that do not consume incremental land. As costs have come down and policies have been enacted to support MW-scale systems, there has been an increasing prevalence of ground-mounted systems. Such systems are often developed on land with little or no high-value alternative use ("brown field sites"), such as capped landfills and contaminated sites. Other types of sites that may be attractive that have little or no competing value include highway medians and inside-the-fence buffer zones (e.g. at substations, airports, power plants, transmission rights of way). Installations at sites with alternative uses ("green field sites") are increasingly being proposed, and would be necessary in increasing quantities over time to meet a 5000 MW New York target. Consumption of green field sites by PV installations is a potentially negative impact of interest. This section attempts to estimate the green field land use impact of the Act's PV targets.

Green field land consumption impact only differs between the three alternative deployments described in Chapter 4:

- **Base:** A *base* PV scenario deployment reflective of load distribution patterns in the state
- **Alt-A:** A more urban- and distributed generation-focused deployment with moderately greater proportions of small-scale and urban installations than the base PV scenario
- **Alt-B:** A more rural, larger-scale-focused deployment than the base PV scenario.

To estimate the impact, three dimensions were estimated: the fraction of systems that are ground-mounted, the development density (e.g. land areas per MW), and the proportion of systems that are green field versus brown field sites. For purposes of this estimate, it is assumed that 100% of MW-scale systems in the Alt-B and Base deployments, and no other installations, are ground mounted.[96] In the Alt-A deployment, a

[96] For large C&I installations, some sites (e.g. substation-scale sites and some buffer areas) might be ground-mounted. For MW-scale installations, some proportion of systems may be all or partly roof-mounted, particularly at the smaller end of the range and in dense urban locations. Such installations are ignored for purposes of this estimate.

smaller percentage of systems are assumed to be ground mounted (5%) because the MW-scale systems in Alt-A are more likely to be relatively small (1-2 MW) and roof mounted in an urban environment. Ground-mounted development density was assumed to be five acres per MW[97] for a single-axis tracking system in New York.[98] If the entire 5,000 MW of PV were ground-mounted, it would require 23,000 acres, or approximately 0.08% of New York's 30 million total acres of land area.

Finally, the proportion of ground-mounted sites that are green field was estimated to linearly increase over time. Installations scenarios range from 25% in 2013 to 90% by 2025 in the Base and Alt B deployment and increasing from 20% in 2013 to 80% in 2025 in the Alt A deployment. The changes reflect the likelihood that brown field sites are less costly and therefore are developed first. Alt-A has a lower green field percentage because of the focus on urban installations. The resulting projections are summarized in Table 64 below. As expected, Alt-B has the highest land use impact, and Alt-A the lowest in this category. Policy decisions could be made that would minimize or potentially eliminate green field development.

Table 64. Land Use Impacts under Alternative Deployment Scenarios

Criteria	Metric (units)	2013-2049	Thru 2017	Thru 2022	Thru 2032
Base PV Scenario Deployment	Acres of green field land used	3004	387	1645	3004
Alt-A Deployment	Acres of green field land used	2632	326	1427	2632
Alt-B Deployment	Acres of green field land used	6008	773	3290	6008

The total amount of land that each of these deployments would require would be small compared to New York State's 30 million acres of total land area. As can be seen in Table 65 below, the % of state land used in all three scenarios is under 0.02%.

Table 65. Land Use Impacts

Deployment	Acres of green field land used	% of state total land
Base PV Scenario Deployment	3,000	0.01%
Alt-A Deployment	2,600	0.009%
Alt-B Deployment	6,000	0.02%

97 Several developers of MW-scale fixed-mount PV installations where consulted, with all reporting densities between 4 and 5 acres per MW.

98 Although the increasing technological conversion efficiency trend (W/m^2) would increase density is likely for various solar technologies, a shift over time to lower-efficiency thin films from crystalline silicon technologies would reduce density. This study has not attempted to assess these offsetting trends, so for simplicity density was held constant.

9. PV POLICIES

9.1. Introduction

This chapter presents a qualitative framework for analyzing different solar policies and applies the framework to several key policy types. The chapter discusses the tradeoffs inherent in each of the core policy options and identifies their strengths and limitations.

Key findings of this Chapter include:

- A comprehensive approach to PV deployment will likely include cash incentives as well as low-cost or no-cost complementary regulations such as streamlined permitting, interconnection standards, and building construction mandates that can reduce the installed cost of PV and drive demand
- There is a range of policy incentive mechanisms, such as upfront payments, standard offer performance-based incentives, and quantity obligations. Although each of these mechanisms has different characteristics, the salient differences between policy types can be reduced through policy design. Even so, there are fundamental differences in terms of overall policy cost, investor security, and implementation
- Renewable Energy Credits (RECs) are a policy tool that can be combined with most policy mechanisms. RECs that are traded on spot markets and are not supported by long-term contracts or price floors, however, are challenging to finance and increase the investor risk, and therefore cost, of quantity obligations
- Cash incentives will be required to achieve the deployment envisioned in this study since there are limitations to the amount of available in-state tax equity and because cash incentives are more cost-effective than tax incentives of comparable size
- Over time, it is expected that cash incentives will sunset as PV becomes more competitive and that PV markets will instead be sustained by regulations
- Incentive rates can be set administratively or through competitive processes. Competitive processes are consistent with New York’s competitive electricity market, although they may create barriers to entry for smaller and less sophisticated market participants. Competitive processes can be used for larger projects, whereas administratively determined incentives can be used to target smaller projects
- The longer the term for a PV incentive, the lower the $/kWh payment needs to be. Longer-term payments therefore create the opportunity for PV to reach parity faster
- Performance-based incentives are most effective at incentivizing production and ensuring that systems are maintained over time

- Policy mechanisms that provide PV projects with their required return in exchange for the transfer of all commodities (e.g. RECs, electricity, and capacity) reduce investor risk of having to sell multiple commodities into multiple markets. Such mechanisms therefore reduce the cost of capital and potential ratepayer impact. Ensuring that all commodities transfer to the incentive provider reduces the ability of PV projects capturing excess profits by selling RECs into different markets after they have received the necessary incentives
- Policy mechanisms that provide fixed, rather than variable, revenue streams reduce investor risk, lower the cost of capital, and reduce ratepayer impacts
- The timing of when revenue and market access are certain for a project is important. Incentives that are known in advance and available on a standard offer basis reduce development risk compared to incentives where developers must submit a bid before fully knowing their costs. The timing of revenue and access certainty can have a material impact on cost of capital and inclusion of risk premiums in bids
- Standard offer PBIs lower investor risk and the costs of financing and enable smaller projects to participate. It can be challenging to set the "right" payment rate for PV generators and standard offer PBIs do not encourage project-on-project competition
- Standard offer upfront payments have similar strengths and limitations as standard offer PBIs. Key differences include that upfront payments do not necessarily create incentives for performance, but they may be more cost-effective for ratepayers than PBIs because they provide PV projects with their required return in a shorter period of time
- Quantity obligations encourage competition between PV projects and favor least cost projects. Quantity obligations that rely on short-term REC trading create revenue uncertainty and are difficult and expensive to finance. Quantity obligations with competitive bidding for long-term contracts can eliminate revenue uncertainty. The costs of competition, however, may be a barrier for smaller-scale projects.

There is a wide range of different policies that can be used to support solar power.[99] Rather than developing an exhaustive catalogue of different policy mechanism, this chapter first lays out a framework to classify solar energy policy mechanisms, and another framework to characterize the pertinent details, and then uses these frameworks to examine and describe several of the major policy mechanisms around the world.

This chapter is organized as follows:

- Section 9.2 introduces a classification framework is introduced to describe the different types of solar policy mechanisms and their uses.

[99] For a detailed discussion of different types of policy options, for example, see recent studies that have sought to describe them in detail (Byrne et al., 2009; DSIRESOLAR, 2011a; Hoff, 2006; Weiss et al., 2006; Wenger and Herig, 1997).

- Section 9.3 presents a framework for characterizing and structuring solar policy mechanisms.
- Section 9.4 applies the policy framework developed in 9.3 to three core policy mechanisms: standard offer upfront payments, standard offer performance-based incentives, and solar quantity obligations.
- Sections 9.5 and 9.6, respectively, summarize solar policy best practices and experience with cost control mechanisms from both the US and abroad, while Section 9.7 presents detailed case studies of PV experience in Germany, Spain, and New Jersey.
- Appendix 2 defines and describes a number of complementary policies, and explores the issues presented in Sections 9.3 to 9.7 in greater detail.

The following discussion of policy incentive types draws distinctions that are true for the prototypical mechanisms, but it is important to note that design aspects of each policy mechanism can be used to reduce their most pronounced limitations. In other words, many of the salient differences that are associated with certain policy labels can be minimized through design. Upfront payments can be linked to performance in a way that reduces key differences with PBIs; standard offer PBIs can include program caps and other mechanisms to contain market growth similar to way that quantity obligations cap total market volume; and policies with spot trading of RECs can include price floors or other long-term contracting mechanisms which can provide revenue stability similar to that of other policy mechanism. Nevertheless, there remain important differences between mechanisms with regard to their overall costs (including transaction and administrative costs), the level of investor security they create (impacting cost of financing), and their implementation challenges. For example, competitive procurements can be tiered to target different project sizes, similar to the manner in standard offer performance-based incentives can be. Both policy mechanisms might ultimately support a diversity of project sizes, but the administrative cost and complexity and the transaction costs under the competitive procurement would likely be higher than those faced under the standard offer PBI. These and other distinctions are discussed in detail in the sections below.

It is also important to note that the broad policy mechanisms described in this section are intended to serve as illustrative examples and benchmarks and should not be considered recommendations as they do not represent the full universe of possible policies that New York could implement. Moreover, each of the policy mechanisms (and their variations) can be combined and implemented as hybrid mechanisms. Mechanisms currently in use in New York, for example, combine strengths of different aspects of these three types to avoid some of the limitations presented by specific policy mechanisms. For example, the New York regional competitive bidding PV incentive program offers a combination of partial up-front payments and performance based incentives awarded through a competitive bidding process. This approach avoids certain limitations discussed later this chapter.

9.2. A PV Policy Classification Framework

There is a number of policy mechanisms available to encourage PVs. PV policies can be grouped into two broad classifications: ***incentives*** and ***regulations***. Incentives include policies that address economic and financial barriers to solar power, such as tax credits, cash payments, and low-interest loan programs, as well as policies to attract and support solar businesses and manufacturing. Regulations are policies that address non-economic barriers to solar power, such as interconnection standards, streamlined permitting, solar access laws, and requirements that public buildings incorporate solar in new construction and renovations.[100]

For purposes of this study, policies can further be classified into ***core*** and ***complementary*** policies. Core policies for the purposes of this study are those cash payment-based incentives that are capable by themselves of driving demand for PV sufficient to meet the targets specified in the Act. Complementary incentives and regulations may be, and often are, established alone or in combination to reduce or eliminate economic and non-economic barriers. Most jurisdictions also combine incentives and regulations to support different market segments.

Furthermore, different types of policies may be appropriate at different stages of market maturity. While incentives may be required to jumpstart market development and achieve the scale required for cost reductions, there is an expectation that incentives will decrease and eventually sunset as solar power becomes increasingly competitive (Osborn, Aitken, & Maycock, 2005).

In later stages of solar market maturity, regulations in the absence of incentives may be sufficient to sustain the market. The use of building codes that require PV to be installed in all new construction or major renovations,[101] for example, may be a tool to support PV market growth without incentives. Such codes have been piloted in New York by the Hugh L. Carey Battery Park City Authority, which started requiring the installation of onsite renewable energy on new construction in the Battery Park City section of Manhattan starting in 2002 (Altman, Blue, Carey, Finnegan, Gelb, & Jaffee, 2002). Several jurisdictions in the US and abroad currently have requirements for public and private development that mandate solar on new buildings, or that buildings at least be built "PV Ready".[102] Such policies could increasingly become

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[100] The most recent *Freeing the Grid* report grades both New York's net metering and interconnection rules with a "B" (Wiedman, Culley, Chapman, Jackson, Varnado, & Rose, 2011). Both grades have improved since 2007, when the net metering policies received a "D" and the interconnection rules received a "C" (Network for New Energy Choices, 2007).

[101] These policies are also known as solar ordinances or energy standards

[102] California and Oregon currently require solar on new public buildings, and several states and cities either require PV or solar thermal on new homes or require the home builders offer it as an option (DSIRE Solar, 2011e). Internationally, Germany, Israel, Portugal and Spain currently require solar thermal on new construction or major renovations, as do municipalities in Ireland and Italy (Dubuisson, 2007; ESTIF, 2007). A related policy is to require that buildings be designed "solar ready" to accommodate solar energy installations in the future. The City of Boston, for example, requires new affordable housing to be designed to solar ready standard, and NREL recently published a guide on solar ready design (Burke, Nelson, & Rickerson, 2008; Lisell, Tetreault, & Watson, 2009).

an option for policymakers in the future. Table 66 below contains an illustrative list of the different types of policies that were considered as part of this study.

Table 66. Examples of PV Policies

PV INCENTIVES	PV REGULATIONS
Performance-based incentives	Streamlined Permitting
Rebates / grants	PV Building Requirements
State Tax Credits	Improved or Uniform Interconnection Standards
State Tax Exemptions	Net Metering[103]
Industry Recruitment and Support	PV Access and PV Rights Laws
State PV Loan Programs	Community PV Regulations
PACE Financing	
On-Bill Financing	
Loan Guarantees	

Many of the complementary solar incentives and regulations are defined and described in Appendix 2. The remainder of this chapter focuses on describing the features of core policy incentives. It is critical to note, however, that many of the complementary policies described in the Appendix could be implemented as part of a comprehensive approach to PV in New York State. Complementary policies could help accelerate adoption and also significantly lower policy costs. Streamlined permitting and best practice interconnection standards, for example, can lower PV development costs, whereas industry support and workforce training programs could lower the cost of installations and of in-state components. Successfully advancing the PACE program at either the residential or commercial levels could lower financing costs and further lower project costs. The implementation of policies such as these are consistent with lower cost deployment trajectories, which assume that project “soft costs” at the same time that hardware prices decline.

9.3. Characterizing PV Policy Incentives

This section focuses primarily on the core statewide incentives that could potentially be the main drivers of PV adoption at the scale envisioned in this study.

Table 67 summarizes major cash and tax incentive mechanisms, organized by their payment structure and the mechanisms set to stimulate the sought after response (i.e. either price or targets).

103 Depending on how defined, net metering can have elements of both incentives and regulations.

Table 67. Alternative Core Incentive Approaches

PAYMENT STRUCTURE	SET A PRICE	SET AN ENERGY GENERATION TARGET
Performance Based Incentive (PBI)	Standard Offer PBI (e.g. German Feed-in Tariff)	Renewable Energy Quantity Obligation (e.g. NYS Main Tier Solicitations - RPS Program)
Capacity-based incentives	Up-front Payment Standard Offer (e.g. NYS Customer-Sited Tier Rebate)	-
Expenditure-based incentives	Up-front Payment Standard Offer (e.g. Federal Investment Tax Credit)	-

Renewable energy incentive definitions are frequently characterized with broad terminology (i.e., feed-in-tariffs, RPS, or RECs) that is often misunderstood or applied with insufficient specificity, meaning different things to different people. From a policy perspective, it is useful to distinguish the "moving parts" behind the broad labels in order to more coherently make comparisons. This section reviews options for structuring solar incentives and the policy trade-offs associated with each option. This approach provides a framework with which to discuss broader policies. The following section provides an overview of major types of incentive policies, draws distinctions between them by referencing the incentive framework, and broadly characterizes their strengths and limitations from the perspectives of ratepayers and investors.

It is important to note that this report refers primarily to ratepayer impact since it is assumed that most policy costs would ultimately be recovered from New York ratepayers embedded in generation service supply charges, through a surcharge on electricity bills, or via other cost recovery mechanisms. It is also possible that funds for PV policies could be collected from taxpayers as part of the state budget. Shifting policy cost recovery to taxpayers instead of ratepayers may shift the burden within New York State since large electricity consumers are not necessarily large taxpayers and vice versa. This could raise issues of equity such as the appropriate way to allocate costs and whether the largest users of energy should bear a proportional burden of mitigating energy-related challenges. From a societal perspective, however, the citizens of New York ultimately bear the full policy cost whether it is recovered from ratepayers or taxpayers.

As a preamble to discussion of specific solar policies and their structural elements, two overarching issues necessary to understand the policy option landscape are first addressed: risk allocation and the role of renewable energy credits (RECs).

9.3.1 PV Incentives and Risk Allocation

A central tenet of finance and contracting is that risk should be allocated to the party best able to manage or absorb the risk (Summit Blue & RMI, 2007). PV policy design elements are influenced by, and address in different ways, four broad areas of risk: performance, market, political and development risks.[104]

- **Performance risks** prevent the system from operating as expected, and can encompass issues ranging from equipment or installation quality, to shading, soiling, tracking malfunctions, and variation in insolation
- **Market risk** (also referred to as revenue risk or merchant risk) relates to the degree to which the value of the electricity or other commodities (e.g. renewable energy credits) produced by a solar system are exposed to fluctuating market forces
- **Political risk** (consisting of regulatory and legislative risk) can be viewed as a special form of market risk. The introduction of PV support policies inherently creates political risk. To the extent that PV installations require certain policies to be economical, investors are vulnerable to the risk that those policies will be eliminated or changed. This could include unforeseen changes in policy targets, technology eligibility or other rules. Such changes have the potential to dramatically and rapidly alter the value of the policy to solar generators and investors in ways that are difficult to predict or hedge. Long-term contracting mechanisms (discussed further below) are designed in large part to address such risk (in addition to market risk).[105]
- **Development risks** occur prior to operation, and encompass three sub-categories of risks that are highly influenced by policy choices (Corfee, Rickerson, Karcher, Grace, Burgers, & Faasen, 2010). These include:
    - ***Development Timing Risk*** is the risk that a project will be delayed or not be completed at all. This risk involves the possibility that a project encounters either (i) a fatal flaw (such as failing to secure required permits, determining that the resource is insufficient, or encountering untenable costs) and is unable to proceed to financing and construction, or (ii) unexpected project delays and increases in funding requirements to complete the permitting process (for instance, due to permit appeals). Project delays become relevant to the extent there is a contractually set milestone schedule or commercial operations date. Projects under the New York RPS central procurement, for example, face this risk since the awarded contracts include development milestones. The potential for missed contractual milestones

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104 Summit Blue and RMI (2007) discuss each of these using a slightly different categorization.

105 Buyers under long-term purchase agreements for renewable energy (e.g. utilities) often seek to incorporate “regulatory change” or “legislative change” language in contracts. Such language would terminate the purchase obligations of the contract if the motivating policy requirement were to go away. Incorporating such ‘outs’ in a contract shifts an unmanageable risk to system owners which undermines a policy’s effectiveness.

increase the cost of development capital and impose a risk of achieving permanent financing, expose the project to contractual penalties, or impose contract termination risk. Policymakers can mitigate these risks by establishing clearly defined processes for siting, permitting and interconnection as well as by establishing within policy-driven contracting approaches a degree of flexibility in commercial operation date

- ***Development Contracting Risk*** involves the risk that investments made in development activities, proposal development, and/or contract negotiations will fail to ultimately yield an off-take agreement with the buyer of electricity, RECs or other commodities. This can occur even when long-term fixed price off-take contracts are made available, but when access to a contract is not assured; when the ultimate level of revenue available is unknown, due to the need to compete for a contract; or when there is a cap on the amount of available incentives. Access is not assured, for example, under the New York RPS central procurement and under the customer-sited tier regional program since projects must compete for incentives. Policymakers can mitigate this risk by providing assured access to off-take contracts

- ***Contract Price Risk*** occurs in a procurement process when a developer has to offer a firm price for selling its output before development contingencies have been fully resolved and project costs are fully known. This risk is exacerbated when procurements happen infrequently or with unknown frequency (hence projects may bid before they are ready, not knowing if or when they will have another chance), or when a material amount of time passes between offering a bid and securing a contact (during which time unhedgeable costs may shift, altering the viability of the offer). Policymakers can influence this risk in the details of policy-driven procurement processes as well as contractual provisions.

9.3.2 Renewable Energy Credits

The use of renewable energy credits or certificates (RECs) as a solar energy policy instrument is widespread, but frequently misunderstood.[106] RECs are not a policy unto themselves, but a policy tool. Not all solar policies use or require RECs, but RECs can be used in the context of policy mechanisms such as renewable energy quantity obligations, standard offer performance-based incentives, and standard offer upfront payments. RECs are tradable certificates, typically in electronic form that perform several functions: they represent the production of 1-MWh of electricity generation from a solar electric generator, carry descriptive characteristics associated with their generator (location, emissions, etc.), and indicate the

[106] RECs that are used specifically for solar, such as in solar-specific renewable energy targets, are often referred to solar renewable energy credits and abbreviated as SRECs. For the purposes of this paper, the term “RECs” is used to refer to both solar and non-solar credits.

timing of the production of that MWh.[107] The holder of an REC has a unique claim to the solar energy production. RECs serve several potentially beneficial purposes but also create some additional risks. RECs create benefits including:

- ***Allow unbundling***: solar energy attributes can be sold separately from the underlying electric energy and capacity, which enables transactional and policy flexibility. Such unbundling is not required, however, and RECs can be bundled together with these other products (Wiser & Barbose, 2008).
- ***Verification*:** RECs serve a means to easily track and verify financial title to, claim to, or sourcing from solar energy and can be used for quantity obligation compliance, environmental disclosure or voluntary green power purchase purposes (Bird & Sumner, Green power marketing in the United States: A status report (2009 data) (NREL/TP-6A20-49403), 2010).
- ***Facilitate commoditization*:** RECs represent a tradable commodity, and this serves a number of useful market purposes, such as trading, standardization, liquidity, and price visibility and discovery.[108]

Use of RECs can also create additional risks. As a creation of policy, RECs are highly exposed to political risk. REC prices can be extremely volatile in the absence of price floors and caps, in many respects behaving like capacity markets, with prices plunging to near zero at times of surplus, and rocketing towards applicable caps under shortage conditions (Ford, Vogstad, & Flynn, 2007). As discussed further, reliance on spot market REC revenue presents challenges for project finance of such capital-intensive investments as PV installations (Baratoff, Black, Burgess, Felt, Garratt, & Guenther, 2007; DB Climate Change Advisors, 2009; Bird, Heeter, & Kreycik, 2011).

While NYSERDA has studied the potential design and implementation of a REC registry and tracking system, New York is one of the only states that currently does not utilize such a system. The Department of Public Service operates an Environmental Disclosure (ED) program which relies on tracking energy transactions (N.Y. PSC, 2011). In its Main Tier RPS program, in the absence of a REC tracking system, NYSERDA obtains RPS Attributes, as described in Chapter 2.

107 RECs have common features but do not always encompass the same set of descriptive characteristics of the generator, or indirect impacts or benefits created by solar energy production. For instance, jurisdictions may differ on whether certain information is described on an REC (e.g. in Massachusetts, a REC includes the use of union labor), or whether tradable emission rights created by the project must be included with or retired in concert with conveyance of the REC (Grace & Rawls, 2007; Holt & Wiser, 2007).

108 Price visibility supports development of a market that can send market price signals of shortage or surplus to market participants.

9.3.3 Options for Structuring PV Incentives

9.3.3.1. Incentive Type (tax credit or cash payment)

The two major types of incentives available to renewable energy generators are cash payments and tax credits. Cash payments are a direct transfer of cash from a central entity, e.g. the government, utility, or competitive electric service provider (ESP) to the owner of a PV system, whereas tax credits enable PV owners to reduce their tax liabilities by a specific amount, reducing the magnitude of market risk exposure. Cash payments and tax credits can be structured to be the same magnitude (e.g. the federal 30% ITC tax credit and 30% cash grant), but the choice of one over the other can have important policy implications. For instance:

- Tax credits depend on project investors having a sufficient "tax appetite" (i.e. tax liability resulting from taxable earnings) to take advantage of them. [109] The recent financial crisis diminished corporate earnings and therefore investor tax appetite available to take advantage of tax credits, creating challenges for financing renewable energy projects reliant on tax incentives (Schwabe, Cory, & Newcomb, 2009). As a result, cash incentives allow for a much broader range of investors, resulting in greater competition and lower equity return requirements (Corfee, Rickerson, Karcher, Grace, Burgers, & Faasen, 2010).
- Tax liability at the state level may also be a limiter on the use of tax credits to achieve the scale of growth envisioned in this study. The Federal tax credit has supported significant renewable energy market growth over the past several decades, but the amount of tax liability at the state level is more constrained. Even in a strong economy, it could be challenging to locate enough state tax liability to effectively monetize state tax credits if such credits were used as the primary driver of state PV programs.[110] The lack of available state tax liability, for example, was recently raised as a concern in the Vermont SPEED proceedings (Rickerson & Karcher, 2009).
- Tax credits require a greater share of equity to be invested in a project in order to assure required debt service coverage ratios are maintained, whereas cash payments are more readily financed with a larger share of debt. Since equity is more expensive than debt, policies based on cash incentives may result in a lower required cost of energy than tax credit incentives policies of equivalent value (Kahn, 1996; Zindler & Tringas, 2010).

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[109] Some tax credits apply to certain types of earnings. For instance, Federal solar tax credits can be utilized by a typical homeowner, whereas renewable energy Section 45 production tax credits can only be taken against passive income (Bolinger, 2010).

[110] States have lower budgets and lower tax rates than the federal government, and also face limits on borrowing.

- Cash payments require that a source of the cash be found[111], whereas tax credits are often adopted with limited attention to the budgetary impact on the unit of government offering the incentive. However, when a tax incentive is of sufficient magnitude to motivate material response, its budget impact can be problematic.

9.3.3.2. Basis for Incentives (performance, capacity, or expenditure)

Incentives can be offered on the basis of project performance, capacity or project expenditure (i.e. cost), each with their own advantages and limitations.

- ***Performance-based incentives (PBIs)*** pay projects based on the amount of kilowatt-hours that they generate (or that they are projected to generate). PBIs reward generators for maximizing their output, which places a premium on efficient project design and ongoing maintenance to keep systems functioning. PBIs are effective at avoiding the installation of systems that fail to produce, perform poorly, or whose performance wanes due to poor maintenance practices. Nevertheless, PBIs can impose higher costs on generators and administrators. First, PBIs usually require monitoring and verification systems which may be cost prohibitive to smaller PV installations. Larger systems can typically afford monitoring because the additional costs represent a smaller percentage of total system cost. Second, PBIs have a higher administrative cost than either capacity-based or expenditure-based approaches because program administrators must maintain an ongoing relationship with generators and may require new metering arrangements, instead of making a one-time payment. Acknowledging the advantages of PBIs, the New York State regional competitive bidding PV incentive program uses PBIs for a portion of its incentive
- ***Capacity-based incentives*** pay generators according to the amount of capacity they install (for example $2/watt). Still, they do not necessarily create an incentive for power production, without the addition of other performance requirements (Barbose, Wiser, & Bolinger, 2006). The New York State PV upfront incentive program and the LIPA Solar Pioneer program provide capacity-based incentives, while a portion of the regional competitive bidding PV incentive program is also paid as a capacity-based incentive
- ***Expenditure-based incentives*** are based on the amount of money that a developer spends on a project (e.g. 30% of total project costs). The Federal ITC as well as state tax credits (such as that available to New York residential customers) fall into this category. If not carefully designed, or capped, these

[111] It should also be noted that there are different ways to source funding cash incentives. The primary policy decision is whether to utilize ratepayer funds or funds collected from the state budget. Budget funds are thought to be less politically secure since they are subject to annual appropriations (Morgan, 2008). For ratepayer funded incentives, a key distinction is whether the annual program budget is known in advance and collected upfront and held in reserve (e.g. a fixed annual system benefits charge that capitalizes a Public Benefits Fund) or whether the charges are passed directly through to ratepayers. Direct pass-throughs are less easy for governments to “raid” for other purposes and do not have an annual cap (Houck & Rickerson, 2009). On the other hand, direct pass-throughs provide policy makers with less control over cost or program overruns.

policies can create perverse incentives for generators to "gold plate" projects by maximizing the project cost rather than focusing on capacity installed or output.

9.3.3.3. Payment Duration (short-term or long-term)

Incentives can be paid near the beginning of the project (e.g. upfront, to buy down the cost of a system) or can be paid out over time.

- **Upfront payments** (i.e. the payment with the shortest possible duration) reduces generator risk, and thus can provide generators with their required rate of return at a lower cost of energy to ratepayers than longer-term incentives. In other words, the shorter the term of the payment, the lower the cost to ratepayers.[112] Still, shorter payment terms enable generators to potentially "walk away" from projects before the end of project system life, and decrease the incentive to maximize either production or cost-effectiveness of energy production. Up-front payments are typically capacity-based or expenditure-based, but performance-based incentives can also be paid up-front. Examples include *performance-based buydowns*, under which a single upfront payment is made based on expected long-term performance, with true-ups based on actual performance, and *expected performance-based buydowns* which required no true-up.[113] The New York regional competitive bidding PV incentive program offers a performance-based buydown type of program, where 30% of the incentive is paid upfront based on expected performance. The remaining incentive is paid based on performance in the first three years and a true-up is performed based on actual performance
- **The tax treatment** of upfront payments also impacts the cost of energy to ratepayers. This occurs through the interaction with other (particularly federal) tax incentives. An upfront payment which is not taxable as income to the project will reduce the depreciable cost basis as well as the value of the ITC. Taxable upfront payments have no impact on the depreciable cost basis or value of the ITC. For projects eligible to receive the Production Tax Credit (PTC), the interaction is different. When any form of government grant, tax-exempt or subsidized financing, or other Federal tax credit is taken, the quantity of PTCs available to the project over time is reduced in proportion to the grant – with the maximum reduction capped at 50% (Bolinger M. , 2006). Therefore, taxable upfront payments deliver greater LCOE benefits at a lesser initial cost to ratepayers by maximizing project owners' ability to utilize federal investment and depreciation incentives

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112 A recent study from Deutsche Bank, for example, calculated that an $18 million upfront payment would provide the same return to a developer as a $29-$37 million performance-based incentive (depending on assumed discount rate) (DB Climate Change Advisors, 2011).

113 California pays an expected performance-based buydown rate to systems under 30 kW in size. The buydown is based on: "per Watt based on your system's expected future performance (factors include CEC-AC system rating, location, orientation and shading) (California Public Utilites Commission, 2011)."

- **Longer-duration incentives** create the potential to capture several benefits. The first is that longer-term incentives can enable PV to reach parity more quickly. This is because longer term contract or payment durations allow the capital costs of PV projects to be spread over a greater number of years (Grace, Rickerson, Porter, DeCesaro, Corfee, & Wingate, 2008). Spreading out the costs over more years lowers the level that the required incentive (e.g. on a $/kWh basis)[114] and therefore lowers the "above market" cost of PV. The second benefit is that long-term incentives can provide a hedge benefit to ratepayers.[115] For ratepayers, there is value in purchasing long-term, fixed price electricity from PV – even at a slight premium – since it protects against future market price volatility. The longer the contract, the lower the premium above market prices and therefore the greater probability that fixed price PV purchases can effectively serve as a hedge. Finally, long-term incentives can reduce PV owner revenue uncertainty in the period following the incentive or contract, reducing investor risk and therefore project costs.

9.3.3.4. Commodities Transferred or Purchased

Incentives (e.g. grants, tax incentives) can be provided to generators without any transaction or obligation, or they can involve the purchase or transfer of commodities. Some incentives, for example, are provided as part of the sale of electricity, while others are provided in exchange for renewable energy credits (RECs) (e.g. rebate programs in Nevada) or renewable energy attributes (e.g. New York Main Tier), and/or other environmental attributes (e.g. air pollution or greenhouse gas emissions attributes). Procurement policies may be for bundled commodities (energy, capacity, RECs) or just for unbundled RECs or energy. The relationship between incentive payments and commodity transactions has implications for project risk: the greater the uncertainty of revenue from different commodities, the higher the risk. Increased risk can impact the costs of capital to finance PV projects and therefore increase the cost to ratepayers of supporting the projects.

- Incentives designed to provide generators with a target return typically transfer all commodities to the purchaser.[116] This also ensures that generators will not then sell their electricity, RECs or other commodities for additional (and excessive) profits

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114 In other words, a 20-year payment would require a lower $/kWh rate than a 10-year payment to deliver the same return to a project.

115 A hedge in the context of energy is typically the purchase of a fixed, long-term contract for energy supply. A hedge is meant to stabilize revenues or costs against short-term electricity price volatility and long term trends. Hedge contracts are purchased at a premium above market prices, but they provide price certainty to the buyer. If volatile energy prices rise above the level of the fixed price contract, the buyer of the long-term hedge contract saves money.

116 Two notable exceptions to this are the California Solar Initiative's performance based incentives for systems 30 kW and over (California Public Utilites Commission, 2011) and the Washington State renewable energy production incentives. Under both of these programs, generators net meter their electricity and retain rights to their RECs in addition to receiving the performance-based incentive.

- If incentives are not designed to provide generators with a target return, then generators must bear the risk of contracting with multiple offtakers for the different commodities (e.g. electricity, RECs, carbon credits, etc.) in order to ensure profitability

  Unbundling also impacts the degree of revenue certainty because of uncertainties in the prices levels, timing, and contract lengths of different revenue streams. If RECs alone are purchased at fixed price, for example, system owners are exposed to electricity market price risk. A net metered PV system might receive a fixed price contract for RECs, but the value of electricity under net metering would remain uncertain because of retail electricity price fluctuations

9.3.3.5. Degree of Revenue Certainty (fixed or variable revenue)

Revenue certainty, central to the ability to finance PV installations, can be established in many ways and varying degrees. At one end of the market risk spectrum, a policy that establishes reliance on a spot REC market provides a means for a system owner to earn a premium, but the incentive is highly variable. On the other end of the spectrum, a long-term contract can provide full revenue certainty.[117] There are many examples of incentives that provide partial revenue certainty, such as fixed payments for electricity or RECs, performance-based incentives covering only a fraction of a project's economic life, or up-front incentives. This revenue certainty can make projects easier and cheaper to finance than those exposed to market revenue fluctuation (Corfee, Rickerson, Karcher, Grace, Burgers, & Faasen, 2010; DB Climate Change Advisors, 2009).

- The benefit of variable incentives is that they can be designed to flexibly react and adapt to changing market conditions. Nevertheless, they decrease revenue certainty because they are exposed to fluctuations in market price and therefore increase investor risk, policy cost, and ratepayer impact
- A price floor, coupled with a variable incentive, can provide some minimum level of certainty to variable incentives, which may be effective if set at a level sufficiently high to attract investment

  As discussed in 9.3.3.3, a long-term fixed payment level is decoupled from market forces and can therefore serve as a hedge against electricity (or fuel) price volatility for ratepayers, in addition to providing significant revenue certainty to investors.

9.3.3.6. Timing of Revenue and Access Certainty

An issue related to revenue certainty is the timing of when this certainty is established. Under some policies, generators know what their revenue will be prior to development, or early in the development

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[117] Pricing RECs on a variable basis under which the price varies inversely with the cost of electricity, referred to as a market gap approach or a contract-for-difference, can mimic the effect of a bundled fixed price contract for electricity and RECs, stabilizing market revenues. This option was explored within the Main Tier of the RPS program in New York State, but was ultimately not pursued.

process; under others, revenue certainty becomes available much later, well into the development process, often after competing for the incentive.

- Incentives can be known and published in advance as a standard offer to eligible projects. When incentive levels or contract revenues are known in advance, this decreases the development risks to generators and investors
- Renewable energy projects will often not fully be able to ascertain and lock in their final cost structure until very late in the development process. If access to the market is only available periodically or on a limited basis – for instance, under periodic auctions or solicitations - projects may have an incentive to enter a program or solicitation to access the market before their costs are well-understood. This may increase the chances that projects that bid successfully will not be developed. If the incentive program contains significant security deposits to discourage speculative bidding, on the other hand, projects may add a risk premium to their bid, thus raising bid prices. Because of the impact on the different categories of development risk, the timing of revenue and access certainty can have a material impact on cost of capital and inclusion of risk premiums in bids
- The timing of revenue and access certainty can also enable or constrain the development of more efficient strategies by market participants. Sophisticated financing structures can reduce the cost of capital for renewable energy projects, but cost hundreds of thousands of dollars in legal cost and financing fees to accomplish. Individual PV projects are typically far too small to absorb these costs necessary to access the benefits of lower costs of capital and must be aggregated into portfolios of projects with a standardized terms in order to do so (Balchandani, Cavaliere, Van't Hof, Buchanan, & Martin, 2011; Friedman, 2011). Such aggregation also takes time and money. These investments make sense, however, if developers know that they will be able to access the market over a protracted timeline.

9.3.3.7. Approach to Setting the Incentive Level (competitive or administrative)

Closely related to the issues of revenue certainty (both degree of certainty and timing) is the issue of how incentives are set. Administrative approaches typically utilize a regulatory process to determine the rates or incentive levels.[118] Competitive approaches rely on some form of direct price competition between generators to establish the level of payment or incentive. Competitive processes, such as the New York RPS main tier procurement, are more consistent with New York's competitive electricity market environment than administrative approaches:

[118] This is similar to traditional cost of service ratemaking that has been employed for conventional generation in a regulated monopoly context (Mintz, 1992). Typically, administrative approaches to renewable incentives set the rates for an entire class of technology rather than for a single plant.

- Competitive approaches to setting incentive levels, such as auctions, competitive tenders, and trading RECs in a market, can use price competition to drive incentive levels downward. The procurement structure will dictate the degree of price differentiation, and auction design details can influence the effectiveness at yielding least-cost results.[119] Competitive processes, however, may introduce transaction costs and barriers to market entry that prevent less capitalized (or less sophisticated) players from taking advantage of the incentive. This is one of the reasons why the current New York State program has pursued both a competitive bidding process for larger systems (above 50 kW) and a capacity-based upfront incentive for smaller systems, allowing a diversity of solar businesses and consumers to participate in the program.
- Administrative rate setting processes may create the conditions for a broader range of capital providers and developers to enter the market. Moreover, they shift competition away from price competition among generators and instead create competition between manufacturers to supply equipment at lower prices in order to maximize profits under the set rate (Menanteau, Finon, & Lamy, 2003).
- There remains considerable debate as to whether administrative or competitive approaches deliver the lowest price.

9.4. Core PV Incentive Policies

This section attempts to broadly and qualitatively characterize the strengths and limitations of three core policy incentive mechanisms by referencing, drawing on the analytical framework described in the preceding section. The core policies include:

- standard offer PBIs;
- standard offer fixed up-front payments (e.g. grants or rebates); and
- renewable energy quantity obligations, including several alternative policy regimes with varying degrees of revenue certainty.

A full discussion of each of the core incentives can be found in Appendix 2 including: a characterization of each mechanism according to each of the policy design options introduced in Section 9.3, a summary of key design variations that are in use internationally, and a detailed description of the strengths and limitations from the perspectives of ratepayers, investors, and policy makers. The sections below contain an abbreviated discussion of the status of each mechanism in the US, as well as a table summarizing the strengths and limitations. Appendix 2 also contains case studies of PV policies in Germany, Spain and New

[119] There are different types of competitive processes (e.g. clearing price versus pay-as-bid or single bid versus descending clock auction), each with its own strengths and limitations, economic efficiencies, potential to deliver lower cost to ratepayers, etc. (Maurer & Barroso, 2011).

Jersey, from which lessons learned about different policy mechanisms have been drawn, and summaries of best practices from different policies.

It is important to note that the report does not recommend one policy type over another. Instead, the emphasis of the policy review is to identify lessons learned that can be built upon as New York contemplates policies appropriate to its own state context.

9.4.1 Standard Offer PBIs

9.4.1.1. Policy Mechanism Overview

Standard offer performance-based incentives[120] are currently the most common renewable energy policy mechanisms in the world and are currently in place in over 50 countries (REN21, 2011). In the US, many states and cities have introduced PBIs for PV, some of which are available on a standard offer basis and some of which are not. At the state level, California, Hawaii, Oregon, Rhode Island, and Vermont have established standard offer PBIs, whereas Gainesville, FL, Palo Alto, CA, San Antonio, TX, Sacramento, CA, and the Tennessee Valley Authority have also established standard offer PBIs or policies similar to them (Bird, Heeter, & Kreycik, 2011). Although the number of states that have adopted standard offer PBI has been comparatively limited to date, standard offer PBIs have driven the majority of global PV capacity and by 2010 had supported 87% of the world's 43 GW of PVs (Tringas, 2011).

Standard offer PBIs create demand and establish a reliable revenue source. As the name implies, the common thread among this class of incentives is a standard offer, available to eligible generators on a first –served basis, for a multi-year term at a known, administratively determined price. Internationally, standard offer PBIs are implemented in many cases in parallel with a variety of other features, regulations and incentives, such as interconnection, purchase and dispatch requirements, as well as contracting guidelines (Rickerson, Hanley, Flynn, & Karcher, 2011).[121] The sections below describe standard offer PBIs utilizing

[120] Which include policies such as feed-in tariffs or CLEAN ('Clean Local Energy Accessible Now') contracts, *see* www.clean-coalition.org

[121] Feed-in tariffs are the primary form of standard offer PBI in Europe. The impact of European FITs has derived from the combination of different policies. The term "feed-in" tariff derives from the 1991 German law that first guaranteed independent power producers the right to connect to and feed their electricity into the grid. Many FITs include requirements that utilities interconnect renewable generation, that renewable energy advance ahead of conventional generation in the interconnection queue, and/or that the cost of interconnection or grid upgrades be passed through to ratepayers (Rickerson, Hanley, Flynn, & Karcher, 2011). FIT policies may also require that utilities not only purchase all of a generator's output (similar to a "must take" contract), but then also prioritize its transmission (i.e. dispatch) ahead of non-renewable generation. If renewable generation must be shut down for technical reasons, some feed-in tariff policies further guarantee that generators will receive payment for the electricity they were unable to sell (similar to a "take or pay" contract). FITs may include provisions that require utilities to offer standard and simplified contracts to generators, rather than requiring generators to negotiate contracts on a case-by-case basis. In the US, federal law and regulation currently prevent elements such as priority interconnection and guaranteed dispatch for large-scale generators (Fink, Porter, & Rogers, 2010). As a result, much of the conversation in the US has focused on the pricing element of standard offer PBIs, although some organizations have recently focused on the non-price elements (see e.g., Regulatory Assistance Project, 2010).

the framework presented above, and discuss the key design options that may significantly impact policy performance.

9.4.1.2. Strengths and Limitations

Standard offer PBIs can lower investor risk and the costs of financing by providing PV projects with a known payment stream. Standard offer PBIs can also encourage smaller projects to participate since there are few barriers to participate in the incentive program. While PBIs have their advantages, it can be challenging to set the "right" payment rate for PV generators. Standard offer PBIs also do not encourage project-on-project competition. Moreover, the ability of standard offer PBIs to lower investment risk and attract a broad range of participants means that the market can grow rapidly. Rapid market growth can be a challenge if not anticipated and managed correctly. Table 68 summarizes the strengths and limitations of standard offer PBIs from the perspective of ratepayer, investors, and policymakers.

Table 68. Strengths and Limitations of Standard Offer BPI

Ratepayer perspective	Investor perspective	Policymaker perspective
<u>STRENGTHS</u> • Low investor risk = low costs of capital and decreased policy costs • Payment based on performance • Long-term, fixed price contract can serve as a hedge against rising energy prices <u>LIMITATIONS</u> • Rates can be set "too high" • No automatic adjustment for changes in market prices	<u>STRENGTHS</u> • Revenue certainty and security • Standard offer lowers transaction cost and development risk • Allows smaller projects to participate <u>LIMITATIONS</u> • A large market response can limit policy durability if not adequately managed	<u>STRENGTHS</u> • Lower policy costs • Easily targeted for specific project types <u>LIMITATIONS</u> • Challenging to get the rate "right" • Purchase requirement on distribution utilities is new for NY • No project-on-project competition

9.4.2 Upfront Payments

9.4.2.1. Policy Overview

While upfront payments do not guarantee a particular revenue stream, they buy down the cost of a PV installation to reduce the project investor's exposure to market risk. Such incentives, usually in the form of grant or rebate programs, have been used to support PV markets in the US for the past decade. As can be seen in the picture below, 17 states including New York, Washington, DC, Puerto Rico and the US Virgin Islands provide upfront payments for PV systems (Figure 51). The structure of upfront payments varies –

some upfront payments are designed to provide project developers with their required return, whereas other upfront payments are partial incentives that are not designed to provide a commercial return. In the near-term, partial incentives may be sufficient to attract innovators or early adopters who are interested in capturing value from the system beyond simple economics (e.g. environmental or prestige value) (Rogers E. , 2003). As PV continues to diffuse into the market, however, it is likely that incentives will need to meet commercial returns in order to attract later-stage adopters. Approximately $2.942 billion have been spent through state rebate or grant programs, supporting a total of 1307.9 MW of PV capacity (Barbose, Darghouth, Wiser, & Seel, 2011). This represents a significant increase over the 40 MW of PV that had been supported by state upfront payment programs by 2003 (Bolinger & Wiser, 2003). In New York, both NYSERDA and LIPA have utilized $189 million in upfront payments to support 51.9 MW of PV.

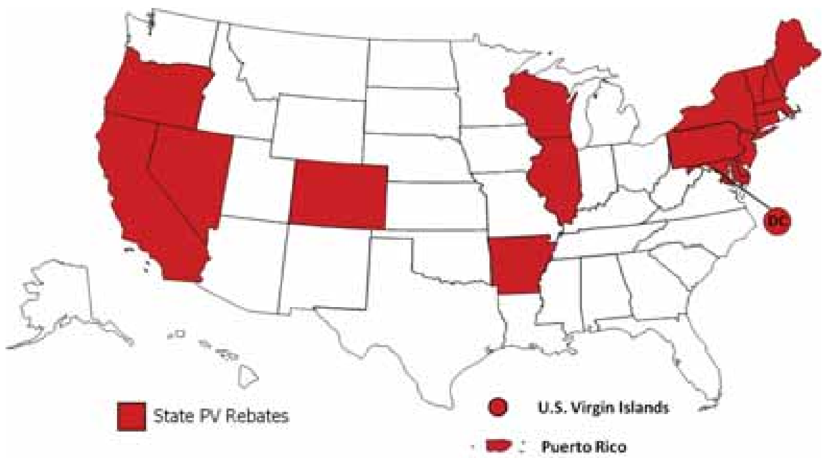

Figure 51. State Upfront PV Incentives (DSIRESOLAR, 2011)

9.4.2.2. Strengths and Limitations

The strengths and limitations of upfront payments are similar to those of PBIs:

- They lower investor risk by providing a known amount of revenue and enable smaller projects to participate if offered on a first come, first-served basis
- It can be challenging to set upfront payments levels at the “right” level.

A key difference is that upfront payments do not necessarily create incentives for performance, although they can be linked to the expected or initial performance of the system. It is also important to note that rebates may be more cost-effective for ratepayers than PBIs because they provide PV projects with their required return in a shorter period of time. Still, the rate impact of having the incentive payments “frontloaded” instead of spread out over time may be challenging for ratepayers. The strengths and limitations of upfront payments are summarized in Table 69.

Table 69. Strengths and Limitations of Standard Offer Upfront Payments

Ratepayer perspective	Investor perspective	Policymaker perspective
STRENGTHS • Upfront payments can provide PV projects with the return they require more cost-effectively than PBIs. LIMITATIONS • The "rate shock" of initial payment for a large volume of installations can be high. • Rates can be set "too high"	STRENGTHS • Revenue certainty and security • Standard offer lowers transaction cost and development risk • Allows smaller projects to participate LIMITATIONS • A large market response can limit policy durability if not adequately managed	STRENGTHS • Can be useful for early adoption in order to persuade innovators to enter market LIMITATIONS • Challenging to get the rate "right" • Typically requires source of funding (e.g. SBC) and a fund, which can be subject to political risk • Not performance based

9.4.3 Renewable Energy Quantity Obligations

9.4.3.1. Policy Overview

Renewable energy quantity obligations[122] create market demand for renewable energy by setting mandatory targets. Quantity obligation policies typically constitute a requirement placed on retail electric suppliers (load serving entities) to supply a minimum percentage or amount of their retail load with eligible sources of renewable energy.[123] Quantity obligation policies in the US are typically backed with penalties of some form, often accompanied by a tradable renewable energy credit program to facilitate compliance, and have never been designed the same by any given state (Wiser & Barbose, 2008). Quantity obligation policies are in place at the national level in ten countries around the world (REN21, 2011).

In the US, quantity obligations are in place in 29 states including New York and Washington D.C. (Figure 52) as well as several territories.[124] In regulated markets, procurement is dominated by long-term bundled contracting for electricity and RECs, via utility solicitations or bilateral negotiations, with regulatory oversight. In contrast, restructured markets with retail choice more often rely on short-term trade in RECs without regulatory oversight, and RECs are often sold unbundled from electricity (Wiser & Barbose, 2008).

122 Renewable energy quantity obligations include policies such as renewable electricity standards, renewable obligations, and renewable resource standards, among others. These policies are generally referred to as renewables portfolio standards (RPS)in the US (see e.g. Wiser and Barbose, 2008). For the purposes of this report, however, the term "RPS" is reserved exclusively to refer to the Renewable Portfolio Standard in New York State (described in Section 1-3). The term RPS does not include voluntary targets such as the renewable energy targets in Indiana, Oklahoma, the Dakotas Utah, Virginia, and West Virginia.

123 Two states – New York and Illinois- employ a central procurement approach, in which a government-authorized entity procures RPS supply on behalf of some or all load-serving entities.

124 Northern Mariana Islands, Puerto Rico, and US Virgin Islands. Guam has established a non-mandatory goal.

In restructured markets, quantity obligation policies establish inelastic demand, tempered only by flexibility mechanisms (such as banking or borrowing). As a result, spot REC prices tend to be extremely volatile: approaching applicable price caps during times of shortage, and approaching zero during periods of surplus. This volatility makes financing based on anticipated revenues extremely challenging (Ford, Vogstad, & Flynn, 2007; Ford, Vogstad, & Flynn, 2007). For this reason, quantity obligation policies in restructured markets are increasingly established with co-policies such as long-term contracts[125] or REC price floors to support revenue stability, as well as to help accomplish policy objectives ranging from capturing in-state economic benefits to supporting emerging technologies (Grace, Donovan, & Melnick, 2011; Wiser, Barbose, & Holt, 2010).

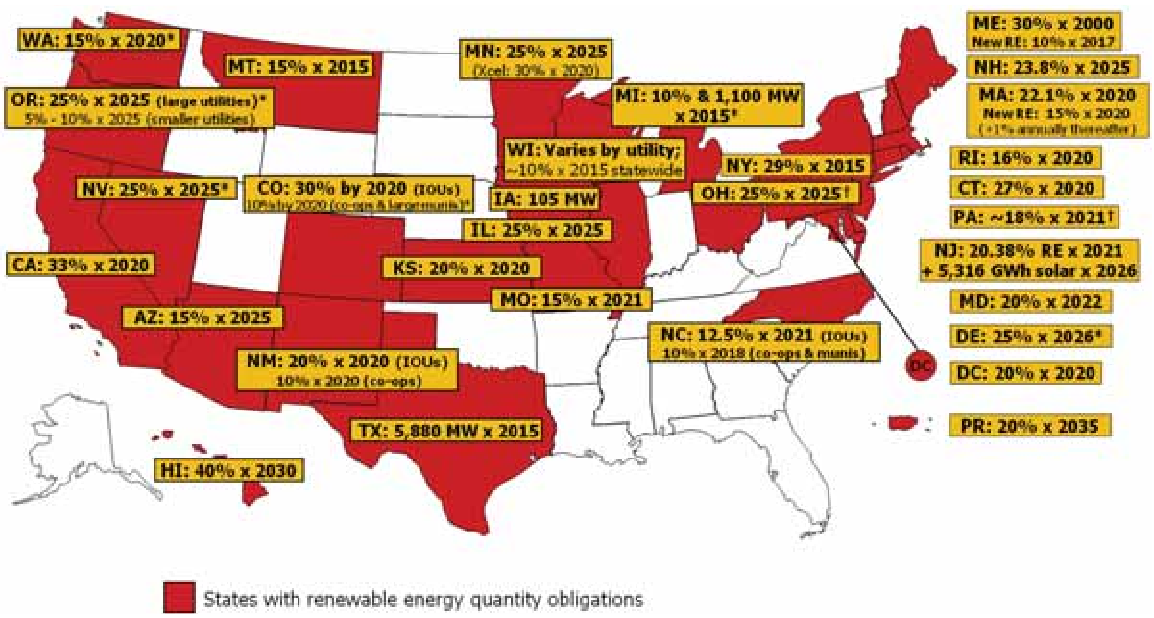

Figure 52. States with Renewable Energy Quantity Obligations[126]

Source: based on DSIRE (2011)

Quantity obligation policies have many variations, as discussed further below and in Appendix 2. While a standard offer PBI or upfront payments are sometimes used to acquire renewable energy towards meeting quantity obligation targets, conventional options fall under one of the following broad categories of varying revenue certainty (Wiser, Barbose, & Holt, 2010):

- Compliance via RECs without any means for creating REC revenue certainty. In this structure, exemplified by the Pennsylvania REC market, there are no long-term contracting policies, and RECs are generally traded via a short-term spot market

125 Examples include the Massachusetts Green Communities Act 15-year renewable energy contract program, New Jersey's utility SREC long-term contract auctions, and New York's 10-year Main Tier RPS contacts.

126 1% of New York's renewable energy goal is assumed to be met by the voluntary market.

- Compliance relying on spot REC markets coupled with policy features or co-policies to establish a price floor or other means to establish a minimum level of revenue available to system owners. New Jersey and Massachusetts solar policies contain these types of features
- Long-term contracts offered via an auction mechanism, exemplified by California's Reverse Auction Mechanism (RAM). Auctions typically are characterized by a time-limited price competition among bidders offering a similar product in one or more bidding rounds[127]
- Long-term contracts offered via competitive solicitations, with winners selected based on a combination of price and non-price factors. There are numerous structural variations within this category, including:
    - Whether the solicitation mechanism is integrated into the quantity obligation (which is common in states without retail competition), or whether the solicitation is a co-policy in states with retail competition that provides for long-term contract procurement by regulated utilities, either in their role as distribution utilities or generation service providers; [128] In New York State, the RPS Main Tier procurement is a competitive solicitation for long-term contracts that is integrated directly into a quantity obligation
    - Whether RECs are procured alone, or bundled with electric energy and/or capacity
    - Whether load serving entities conduct the solicitations on their own or whether the solicitation is conducted by a central authority (e.g. NYSERDA Main Tier RPS) on behalf of the LSEs.

127 Experience implementing auctions for long-term contracts from pre-operational generators is limited, because development risks are difficult to equalize without the use of substantial non-performance security.

128 A number of markets use combinations of policies, for example, providing long-term contracts for a portion of the load served by regulated entities (generation service providers of last resort) in competitive retail markets (e.g. Massachusetts, Connecticut, Rhode Island, Maine, Delaware).

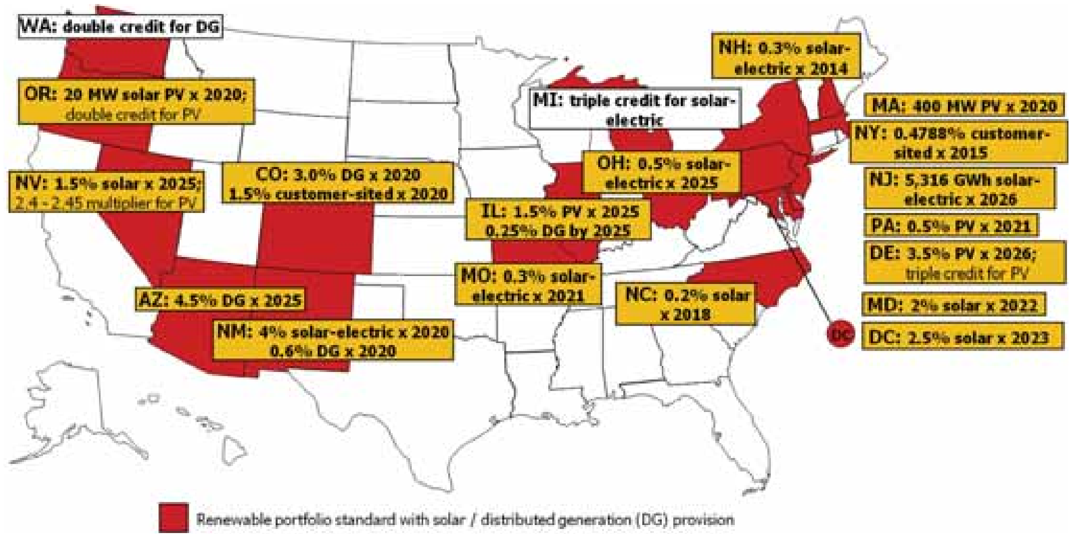

Figure 53. Quantity Obligations Explicitly Supporting PV *(DSIRE 2011)*

Sixteen states, plus Washington D.C, have established RPS policy provisions to support solar and/or distributed generation, see Figure 53. PV installations have been supported through solar tiers of a larger quantity obligations for new renewables,[129] REC multipliers giving extra credit for solar or distributed generation, or contracting policies for solar that allow payments in excess of non-solar price caps.[130] Most solar obligations explicitly utilize solar renewable energy credits (SRECs), whose value differs from the RECs created by other new renewables.

9.4.3.2. Strengths and Limitations

The strengths of quantity obligations are that they encourage competition between PV projects and favor least cost projects. The limitations of quantity obligations differ depending on whether the policy relies exclusively on short-term REC trading or whether long-term contracts are available. Short-term REC trading can lead to uncertain revenues PV projects and can make them difficult and expensive to finance. Competitive bidding can eliminate the problem of uncertain payment streams by awarding PV projects long-term contracts. However, not all PV projects have enough money and sophistication to effectively compete for long-term contracts. As a result, competitive bidding can serve as barrier to smaller-scale projects. The strengths and limitations of quantity obligations are summarized in Table 70.

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[129] DC, DE, IL, MA, MD, MO, NC, NH, NJ, NM, NV, OH, OR, PA (Wiser, Barbose, & Holt, 2010).

[130] Connecticut's recently adopted Public Act 11-80 established a zero-emission renewable energy credit (ZREC) long-term contracting requirement mandates a defined budget to be spent by the state's investor-owned utilities to competitively procure long-term contracts for the purchase of RECs usable towards compliance with the state's Class I RPS (price cap = $55 per MWh) from eligible generation subject to a $350 per MWh price cap.

Table 70. Strengths and Limitations of Quantity Obligations

Ratepayer perspective	Investor perspective	Policymaker perspective
STRENGTHS • Favors least cost projects • Competition encourages lower costs LIMITATIONS • Prices can be inflated by investor risk premiums (if no long-term contracts) • Market prices can spike during REC shortage	STRENGTHS • Creates demand and a market • Supports financing (if long-term contracts, price floors, etc.) LIMITATIONS • Price volatility hampers financing (if no long-term contracts) • Policy changes can impact market prices and project revenue	STRENGTHS • Low administrative burden for spot market trading • Fits restructured markets • Quantity of supply known in advance • Competitively neutral LIMITATIONS • Unknown cost • Can create barriers for emerging technologies or smaller projects

9.5. Best Practices

PV policies can be evaluated from a number of perspectives, and best practices that may satisfy the needs of some market actors may not be considered best practices from perspectives. Generally, PV investors and project developers prefer policies that are stable, transparent and lead to long-term certainty. Policies of this nature can lower capital costs and limit investor risk exposure. From a ratepayer perspective, best practices may include policies that ensure cost effectiveness and provide market oversight and consumer protection. Ratepayers also have an interest in supporting incentives that are structured to ensure well-sited and properly functioning PV systems. Finally, best practices from a policy maker perspective limit both administrative costs and burdens, and can be implemented within existing regulatory frameworks.

Table 71 describes several policy best practices. A more detailed discussion of best practices can be found in Appendix 2.

Table 71. Investor, Ratepayer and Policymaker Best Practices

Perspective	Best Practice Goal	Best Practice
Investor	• Stability • Transparency • Certainty	• New Jersey utility contracting program • Massachusetts SREC price floor
Ratepayer	• Well-sited systems • Consumer protection • Strategic equity goals	• Performance based incentives • Market oversight activities • Incentive adders to support strategic goals
Policymaker	• Low administrative burden	• Leverage existing program infrastructure and monitoring platforms

9.6. Cost Control Mechanisms

A key design feature of all PV policy mechanisms is the approach to controlling the overall cost of the incentives. Generally, there are two inter-related strategies for controlling policy cost: controlling market volume (i.e. the amount of PV that is installed) and controlling market price (i.e. the amount that PV generators get paid). Both volume and price approaches are currently used for each of the policy mechanisms considered in this Chapter. Standard offer PBIs and upfront payments typically utilize the same suite of cost control mechanisms, whereas the cost control approaches used for quantity obligations depends on whether the primary procurement mechanism is spot SREC trading or long-term contracts. Table 72 below summarizes the cost control approaches associated with each mechanism and Appendix 2 describes these mechanisms in greater detail.

Table 72. Cost Control Approaches for PV Policy Mechanisms

Standard Offer PBIs & Upfront Payments	Quantity Obligations: Spot Trading	Quantity Obligations: Competitive Procurement under LT Contracts
• Set conservative rates • Automatic adjustments • Overall and/or annual caps • Fixed budget • Periodic review	• Broad eligibility to participate • Alternative compliance / price caps • Quantity targets • Rate impact caps	• Procurement design • Benchmark prices • Tier differentiation • Fixed budget • Caps • Frequency and size

9.7. PV Policy Case Studies

Germany

Over the past few years, Germany has consistently been the largest PV market in the world, installing more than 7 GW annually in both 2010 and 2011. This market has been supported by a long-standing PV feed-in tariff that offers fixed price 20-year contract. The German incentive program currently include a series of differentiated rates for multiple system sizes, as well as a transparent, automatic mechanism to lower tariff rates based on market performance. Stable market growth has led to significant installed cost declines in Germany, and many analysts are predicting that tariff rates will be at or below retail electricity prices in 2012.

The stability of the German incentive program has led to local job growth throughout the PV supply chain. Some of the leading global PV and inverter manufacturers are located in Germany in addition to its robust installer base. Table 73 outlines several strengths and weaknesses of the German incentive program. A fully case study of the German feed-in tariff can be found in Appendix 2.

Table 73. German PV Policy Strengths and Weakneseses

Policy Strengths
Driving rapid market expansion
Supporting world's largest PV market
Policy structure minimizes risks for developers and investors
Differentiated rates and standard offers support growth among all system sizes
Majority of new capacity is from smaller-scale systems
Program participation not tied to building loads
Policy Weaknesses
Lack of cap and large market response mean high ratepayer bill impacts
Annual automatic adjustment mechanism has not kept pace with market

Spain

Like Germany, Spain uses a PV-specific feed-in tariff to meet its solar goals. Nevertheless, while the German policy has been notable for its stability, the Spanish PV feed-in tariff has undergone a number of significant changes in the latter part of the last decade that have led to a boom-bust market cycle followed by more tempered market growth in recent years. In 2008, a poorly implemented tariff rate degression led to a rapid scale up of the Spanish PV market that significantly outstripped the goals of the program. The Spanish rate changes did not anticipate the ability of the PV market to rapidly scale when a rate degression was announced too far in advance. Developers flooded the market in an effort to secure a higher tariff payment before the administratively set deadline. Nearly 3,000MW of PV was developed in 2008, increasing the country's installed capacity fivefold.

The Spanish feed-in tariff demonstrates the potential for poorly planned standard offer policies to over stimulate a market leading to unexpected policy costs. Table 74 highlights some of the strengths and weakness of the Spanish PV feed-in tariff. A further discussion of the Spanish solar market and PV policy can be found in Appendix 2.

Table 74. Spanish PV Policy Strengths and Weakneseses

POLICY STRENGTHS
Created the Spanish PV industry
Long-term feed-in tariff contract provided financing and investment opportunities during the years prior to 2008
Created a large market for and experience with ground-mounted PV systems
POLICY WEAKNESSES
Boom and bust cycle due to feed-in tariff rate fluctuations
Overrun on policy and program caps
Tariff rate adjustment triggers did not effectively follow PV price reduction trends
Design flaws that focused on wind power projects did not translate to PV projects
Retroactive payment and contract adjustments

New Jersey

For the past several years, New Jersey has been the largest East Coast PV market. In 2010 the state transitioned from a hybrid incentive program, with both upfront payments and a solar requirement in its RPS to an entirely RPS-based program. During 2010 and 2011, market prices for the state's SREC program had been near the administratively established alternative compliance payment. Recently, the New Jersey market has become over-supplied, with enough generation capacity already installed to meet the compliance requirements for several years in the future. This has led to a collapse in SREC prices and has reportedly slowed the growth of the New Jersey solar market.

New Jersey's utility regulations require the state's investor owned utilities to support the state's SREC market through mandated long-term contracting or dedicated solar financing programs. While these utility-operated initiatives have created investor security for projects that are able to take advantage of them, they do have limited availability. New Jersey also permits its investor owned utilities to develop and own PV generation. This has supported the development of a megawatt scale PV installation market in New Jersey.

Table 75 below list several strengths and weaknesses of the New Jersey incentive program. A case study of New Jersey solar policies is available in Appendix 2.

Table 75. New Jersey PV Policy Strengths and Weaknesses

POLICY STRENGTHS
Market-based solution that adjusts to declining PV installation prices
SREC price support through long-term contracting under utility programs
Long time horizon for market solar requirements
Adequate SACP to support solar projects
Direct ownership by utilities has spurred market of large-scale installations
POLICY WEAKNESSES
SREC price support through utility financing and contracting programs is limited
Near-term oversupply has led to swings in SREC prices and uncertainty in the market

10. ANALYSIS OF PV POLICY MECHANISMS

10.1. Introduction

Based on current experience in national and international PV markets, it is clear that a wide range of potential policies are available for driving PV markets in New York State. Building on the background provided in previous chapters, this chapter explains the decision process by which a broad range of potential policies was narrowed to four policies selected for analysis in this Study. This chapter also explains the key modeling considerations implicated by the four chosen policies, and the resultant cost premiums and rate impacts.

Key findings of this Chapter include:

- The difference among the three least expensive policy mechanisms is less than 17%, which is potentially smaller than the impact of specific design choices including targeting deployment to specific installation types and locations.
- An up-front payment incentives for smaller customers (and central procurement for larger customers) similar to the policy approach used in New York for the RPS is the least expensive mechanism analyzed as part of this Study.
- A quantity obligation with price floor (similar to the policies in MA and NJ) is projected to cost 50% more than the least cost policy mechanism
- Many complementary policies could be implemented at low or no overall cost in parallel with the analyzed incentive polices, on either a local or state-wide basis, potentially reducing the cost of and removing barriers to reaching the targets, and should therefore be considered as New York refines its solar policies
- Costs to compete for and potentially negotiate a contract could be prohibitive for smaller-scale generators
- Policies which shift risk away from PV investors tend to increase investor security, decrease the cost of capital, and thereby decrease the cost of PV
- Choices of policy mechanism that reduce investor risk, administrative and transaction costs will have lower peak and average direct and net impacts on ratepayers.

This chapter is organized as follows

- Section 10.2 surveys complementary state and federal incentives and regulations to determine how and if they could be implemented in parallel with the three broad policy types to drive PV market scale-up in New York State
- Section 10.3 presents the four policies selected for quantitative analysis. The Section reviews the risk allocation transaction cost implications and who pays for each policy approach
- Section 10.4 presents the key features and parameters that serve as the inputs to modeling simulations.
- Section 10.5 presents a comparison of the rate impacts of the different selected policy mechanisms.

10.2. Candidate Policies

10.2.1 The Role of Complementary Policies

Although the cost of PV has declined significantly during the past several years, this study demonstrates that the PV market will continue to require incentives in the near-term. Based on the international benchmarking exercise and framework analysis conducted in Chapter 9, this study focuses on the core incentive policies and structures: standard offer upfront payments and PBIs, quantity obligations, and their variations. This section discusses the potential roles of complementary state incentives and regulations, as well as Federal incentives. With a few exceptions discussed below in Section 10.2.1.2, this report did not explicitly consider or analyze most of the regulations described in Table 66 (Chapter 9) and Appendix 2, such as streamlined permitting and solar access laws. It is likely, however, that many of these policies could be implemented at low or no overall cost in parallel with incentive polices, on either a local or state-wide basis and should therefore be considered as New York refines its solar policies.

10.2.1.1. State Financial Incentives

Financial incentives in addition to the policies drawn from Section 9.3.3.7 were also considered during the course of this research effort. Section 9.2 describes the role that complementary incentive policies could play in supporting the rapid scale-up of PV in parallel with the core policies. Each incentive is considered within the context of how it could be structured to scale-up the PV market: for example, whether existing policies could be expanded to deal with a broader range of customer classes (if applicable) or whether new policies could be structured to support large volumes of projects with different systems types and sizes. The pros, cons, and constraints of each scale-up strategy are also discussed. Based on the analysis below, this study assumes that none of the complementary policies will be included in significant market scale-up scenarios.[131]

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131 If any of these complementary policies were to be included in the quantitative modeling, then it would be assumed that the base incentives would be adjusted to take these additional incentives into account. In other words, if a state tax credit were to be assumed in conjunction with a standard PBI, the required standard PBI level would be calculated at a lower level in order to account for the additional incentive.

Table 76. Complementary PV Incentives

POLICY	POTENTIAL APPROACH FOR SCALING UP MARKET	PROS AND CONS	CONSTRAINTS TO SCALE
State tax credit	An expansion of the existing personal state tax credit currently available to owners of residential systems, to support commercial systems as well as residential systems	Pros • Creates additional revenue certainty Cons • Redundant with direct payments to solar generators • Requires sufficient state tax liability to monetize and incurs additional costs of capital from greater share of equity required	There may not be sufficient investor in-state tax liability to support the target market growth assumed in this study. State budget impact may make tax credits at this scale infeasible. To the degree that lease programs or other third-party ownership models are seen as key to widespread adoption, such third-party owners would not be eligible to claim the state income tax credit.
Property tax exemption	A return to mandatory property tax exemptions for all PV projects (as existed in 1977-1991), rather than giving municipalities the opportunity to opt-out	Pros • Reduces operating costs at solar sites Cons • Reduces tax revenue to municipalities	Expanding the property tax exemption would remove a municipal revenue stream and may be politically difficult. To date, 37 municipalities and 126 school districts have opted out of the exemption (N.Y. Dept. of Taxation and Finance, 2011)
Sales tax exemption	An expansion of the existing sales tax exemption to include non-residential systems as well	Pros • Reduces costs of project development Cons • Reduces tax revenue to state government and municipalities (for those eligible to opt out)	Expanding the sales tax exemption would decrease state tax revenue.

POLICY	POTENTIAL APPROACH FOR SCALING UP MARKET	PROS AND CONS	CONSTRAINTS TO SCALE
PV loan programs	The introduction of a consumer or commercial loan program dedicated to PV and arranged with a financial institution. Typically there are special arrangements such as below-market interest rates, extended loan terms, and/or waivers of fees and closing costs.	Pros • Attractive financing helps overcome hurdle of PV's upfront cost. Cons • Success depends on credit-worthiness of borrower • Interest rates are already low and public money may be deployed more efficiently through other mechanisms	Funds needed for loan buy-down (if applicable) could compete with other policies (i.e. standard offer PBIs, quantity obligations, and upfront payments) The market appears to be supplanting the potential role for streamlined loan program models with 3rd party ownership models (Kann, 2011; NREL, 2009)
Property Assessed Clean Energy (PACE) financing	Broad implementation of existing municipal authority to allow solar installation to be financed by adding a tax liability to the property and paying back a loan back through the property tax bill.	Pros • Supports installations of solar in the case where the property owner is making the investment, lowers costs of financing, and ensures loan repayment Cons • Federal mortgage loan backers currently do not permit residential PACE financing (FHFA, 2010)	PACE for residential systems is currently not feasible given current opposition from federal entities. Still, future legislative action may revive PACE as a possibility. The NY Legislature has authorized municipal authority to offer sustainable energy loan programs.

10.2.1.2. State Regulatory Policies

Of the full range of potential regulatory policies, only two were selected for additional consideration in this report: net metering and utility ownership of PV. Table 77 below contains perspectives on the ability of both policies to support scale-up of the PV market . Of the two, only net metering is utilized in further modeling in this report.

Table 77. Complementary PV Regulations

POLICY	POTENTIAL APPROACH FOR SCALING UP MARKET	PROS AND CONS	CONSTRAINTS TO SCALE
Net metering	Remove the program cap for solar net metering in each utility service territory[132]	Pros • Enables customer generators to offset their retail load Cons • Net metering decreases revenue for distribution companies, which (if allowed by rate regulators) is shifted to non-participants)	To reach 5000 MW, the cumulative decrease in utility revenue from behind-the-meter generation could require significant cross subsidies
Utility ownership	Investor-owned utilities would be permitted to own PV generation similar to Massachusetts[133] and Connecticut[134]	Pros • Utilities have low-cost financing, access to capital, long-term investment horizons, knowledge of optimal interconnection sites, and ownership of sites such as substations or brownfields. Cons • Utility ownership model is not compatible with NY's preference for a market-based structure	Under current New York policy, investor-owned utilities are prohibited from owning electric generation. Utility ownership of electric generation does not fit the current electricity market structure and philosophy in New York State. Other restructured states do allow utilities to own limited amounts of PV, but not the magnitude of capacity contemplated in this report

10.2.1.3. Federal Incentives

The study assumes that generators will be able to access all federal incentives that are assumed to be available in the Base Cost Case described in Chapter 3. These include the federal ITC[135] and the standard 5-year MACRS accelerated depreciation schedule. It will be assumed that the value of these incentives is taken into account when incentive levels are determined (i.e. standard offer PBI levels would be lower than they otherwise would need to be because generators will claim the federal benefits). Federal grant programs which are available on a limited or temporary basis (e.g. the 1603 cash grant, the Department of Agriculture REAP grants) are not considered in the study.

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132 Several states do not currently have a program cap on their net metering programs. They include: AZ, AK, CO, CT, DC, FL, IA, ME, MN, MT, NM, NC, ND, OH, OK, PA, PR, WI, and WY (Wiedman et al., 2011)

133 Green Communities Act, 2008.

134 Public Act 11-80, 2011.

135 Which reverts back to 10% after 2016.

10.2.2 "Pure" Core Policy Mechanisms

In order to select the policy mechanisms for modeling, a series of six candidate policy mechanisms was developed, consisting of different variations of standard offer PBIs, quantity obligations, and upfront payments. These paths are referred to as pure policy mechanisms because they are based on a single policy type, which is assumed to apply to all installation sizes and locations. As can be seen in Figure 54 below, four of the policy mechanisms represent a variation of solar quantity obligations. Of these, two (1a and 1b) involve tradable RECs without contracts, whereas two (2a and 2b) involve competitive procurements for long-term contracts. The final two pure policy mechanisms (3 and 4) are standard offer PBIs and standard offer upfront payments. Each of these pure policy mechanisms is described in greater detail below. The high-level descriptions are then accompanied by tables that include overviews of additional defining characteristics, the risk allocation associated with each policy, and a qualitative summary of each policy's transaction costs.

The following discussion draws distinctions that apply to the prototypical mechanisms discussed herein. It is important to note that specific design aspects of each policy mechanism can be used to achieve similar deployment response, if desired, although with different costs, risks and challenges. As discussed further below, these policy mechanisms can be applied across all installation types and sizes, or different mechanisms can be applied in combination, targeted to those installation types for which they are best suited.

Figure 54. "Pure" Incentive Policy Mechanism Alternatives for Driving PV Demand

- **<u>Policy 1a - Traditional PV Quantity Obligation with Tradable SRECs (QO with Tradable SRECs)</u>.** This policy mechanism is similar to Pennsylvania's solar quantity obligation policy, a solar

RPS tier. Under this policy, there would be a solar-specific quantity obligation, supported by tradable solar renewable energy credits. In order to generate revenue, PV developers would sell their SRECs to LSEs in the open market. The key design considerations for this policy would be how to set the ceiling price (i.e. alternative compliance payment) level and identify other flexibility mechanisms to build into the policy, such as REC banking rules. This policy mechanism provides no revenue predictability and developers will therefore face difficulties with financing projects, a key implementation challenge

- **Policy 1b - PV Quantity Obligation with Tradable SRECs and Price Floor (QO with tradable SRECs + Price Floor)**. This policy mechanism is the same as policy 1a above, but with an additional feature to establish a minimum market price. Massachusetts, New Jersey and Belgium have each introduced different types of price floor mechanisms with the goal of providing developers and investors with greater revenue certainty. The key design considerations for this policy mechanism are the same as in path 1a, but with the additional complexity of designing and funding the floor price mechanism. LSEs would purchase the RECs, but the price floor could either be provided by the utilities or by the government
- **Policy 2a - Auction for Long-Term Contracts (Auction for LT Contracts).** There are few examples of PV auctions for long-term contracts in the US. The Reverse Auction Mechanism in California is the closest corollary, but it enables a broad range of technologies to compete rather than just PV. This policy includes a solar obligation supported by competitively offered long-term contracts. In principle, such an auction could be conducted by either the EDCs or by using a central procurement (CP) approach as discussed in Policy 2b. The key design considerations include: contract length, auction design (e.g. pay-as-bid or clearing price), contractual milestones, bid and contract security, and whether contracts would be for SRECs (e.g. if procurements is managed by a central procurement entity) or for SRECs bundled with electricity (e.g. if procurement is managed by a distribution company). A key implementation challenge would be how (or if) to create a level playing field among generators that may face different types and levels of development risk
- **Policy 2b - Central procurement RFP or Tender (Central Procurement)**.[136] This policy mechanism is similar to the current New York RPS Main Tier central procurement system. There would be a solar obligation supported by long-term contracts for SRECs only, obtained through a competitive procurement process. The key design considerations would be similar to those in Path 2a. The key implementation challenges include how to balance budget limitations with the need to mitigate project revenue risk and make the contracts financeable and how best to disencumber money from underperforming projects

[136] The New York regional competitive bidding PV incentive program has elements of this approach given the competitive central procurement process.

- **<u>Policy 3 – Standard offer PBIs , Administratively-determined price (Standard Offer PBI)</u>.** This policy mechanism would be similar to the Vermont Standard Offer for Qualifying SPEED[137] and Rhode Island's Distributed Generation Standard Contracts. Standard-offer performance-based incentives would be offered by LSEs to projects of all sizes on a first come, first served basis. The contracts would include long-term, fixed price payments. The key design considerations include setting contract duration and establishing queuing rules if caps are included. The key implementation challenges including setting the payment levels and controlling market response to the incentive over time
- **<u>Policy 4 - Fixed up-front payments (Standard Offer Rebate)</u>**.[138]This policy mechanism is similar to the approach currently utilized in the RPS Customer-Sited Tier and in many other state rebate programs. Upfront payments based on capacity ($/watt) would be provided by a central procurement entity on a standard offer basis to all project sizes. The key design considerations are how best to insert safeguards to ensure that systems performed as projected. The implementation challenges are similar to those with standard offer PBIs

10.2.2.1. Pure Incentive Policies: Additional Defining Characteristics

Additional defining characteristics of the pure incentive policy mechanisms are described in Table 78 below. The policy mechanisms are ordered from the perspective of risk to developers and investors, from highest risk (1A) to lowest risk (3 and 4).

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137 Sustainably Priced Energy Enterprise Development .

138 The New York regional competitive bidding PV incentive program has elements of this approach as the incentive is paid in-part up-front; however, the mechanism seeks to mitigate some of the limitations of this "pure" policy mechanism by linking payments to performance over the first three years of operation and by making awards on a competitive basis.

Table 78. Defining Characteristics of Pure Policy Mechanisms

MECHANISM ➔ PARAMETERS ↓	1A - SOLAR QO WITH TRADABLE SRECS	1B - SOLAR QO WITH TRADABLE SRECS + PRICE FLOOR	2A - AUCTION FOR LT CONTRACTS	2B - CENTRAL PROCURE-MENT	3 - STANDARD OFFER PBI	4 – STANDARD OFFER REBATE
Incentive type (cash v. tax)	Cash	Cash	Cash	Cash	Cash	Cash
Basis for incentives *P = performance* *C = capacity*	P	P	P	P	P	C[139]
Commodities transferred / purchased	SRECS only	SRECs only	SRECs only (CP) **OR** Bundled SRECs + electricity (LSE)	SRECs only	SRECs only **OR** Bundled SRECs + electricity	Either no commodities, or in some cases, SRECS (e.g. for 3 years like in NY RPS CST)
Duration (upfront v. over time; qualification life)	Long-term; qualification open-ended for life of policy	Long-term; qualification open-ended for life of policy	Long-term; (post – contract qualification unclear)	Long-term (post – contract qualification unclear)	Long-term (usually equal to policy qualification life)	Upfront
Degree of Revenue Certainty (fixed v. variable)	None; Variable for electricity sales	Minimum; Variable above floor	Fixed (typically 10-20 yrs) for purchases during contract term, variable post-contract	Fixed (typically 10-20 yrs)) for purchases during contract term	Fixed (typically 15-25 yrs) for purchases	Fixed (for incentive); variable for electricity sales
Timing of revenue and access certainty	None	Floor price may be known in advance; access to floor depends on details	Known only after competing	Known only after competing	Known in advance, reliable access	Known in advance, reliable access
How price is determined	Commodity market	Commodity market; Administratively set price floor	Competitive process	Competitive process	Administratively set	Administratively set

139 It is assumed that policies using capacity based and/or upfront payments include best practice performance guarantees such as warranty requirements, inspection requirements, and 30-day system test periods, as appropriate.

MECHANISM ➔ PARAMETERS ↓	1A - SOLAR QO WITH TRADABLE SRECS	1B - SOLAR QO WITH TRADABLE SRECS + PRICE FLOOR	2A - AUCTION FOR LT CONTRACTS	2B - CENTRAL PROCURE-MENT	3 - STANDARD OFFER PBI	4 – STANDARD OFFER REBATE
Participation open to Customer side vs. utility side of meter	Either (design choice)	Either (design choice)	Either (design choice)	Either (design choice)	Typically utility-side	Typically customer side

10.2.2.2. Pure Incentive Policy Risk Allocation

The manner in which each policy mechanism allocates risk to different parties such as the project owners, ratepayers, LSEs, or the state, emerged as a key evaluation criteria during the policy selection process. Table 79, which draws on the discussion of risk allocation from Section 9.3.1, also notes cases where certain risks are mitigated or eliminated (rather than allocated). Policies that shift risk away from PV investors tend to increase investor security, decrease the cost of capital, and thereby decrease the cost of PV.

Table 79. Risk Allocation for Pure Policies

	MECHANISM ➔ PARAMETERS↓	1A - SOLAR QO WITH TRADABLE SRECS	1B - SOLAR QO WITH TRADABLE SRECS + PRICE FLOOR	2A - AUCTION FOR LT CONTRACTS	2B - CENTRAL PROCURE-MENT	3 - STANDARD OFFER PBI	4 – STANDARD OFFER REBATE
RISK ALLOCATION	Performance	Project	Project	Project	Project	Project	Ratepayers and Project[140]
	Market	Project	Project, but lower than SREC-only model b/c of price floor	LSE or Ratepayers	Rate-payers	LSE, Ratepayers	State
	Political	Project	Project	Ratepayers	Rate-payers	Largely Eliminated	State
	Development	Project	Project	Project	Project	Largely Eliminated	Largely Eliminated

140 The degree to which project performance risk is allocated to the ratepayers (rather than to investors) will depend on the degree to which project performance requirements (e.g. warranties, etc.) are built into the program rules governing award of the upfront payment.

10.2.2.3. Pure Incentive Policy Transaction Costs

Transaction costs are the costs that developers incur to access the market and secure incentives. Standard offer PBIs and upfront payments can have low transaction costs, depending on how they are designed. Standard offer PBIs, for example, can eliminate many transaction costs and risks by providing generators with both revenue and access certainty before the project development process even begins. Tradable RECs and competitive procurement processes each introduce greater transaction costs.

The process to qualify a project to receive SRECs (i.e., certification) is not significantly more onerous than the process of submitting a rebate or standard offer PBI application. Unlike rebates and standard offer PBIs, however, the generator is responsible for marketing and selling SRECs either as 'minted' or under a term contract. The marketing and contracting process introduces additional transaction costs for developers (or their REC brokers)[141] and may create hurdles for smaller, unsophisticated market participants (e.g., residential customers).

The competitive procurement process can create significant transaction costs, depending on how the process is designed. These include the costs of ascertaining a viable bid price based on the developer's current understanding of its cost structure, preparing and submitting the bid, posting bid and contract security, and then potentially negotiating a contract if successful. The costs to compete for and potentially negotiate a contract could be prohibitive for smaller-scale generators (e.g., residential and commercial site hosts). Table 80 below summarizes qualitatively how the transaction costs of the different pure policy mechanisms compare.

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141 A useful data point for SREC trading transaction costs may be brokerage fees.

Table 80. Transaction Costs of Pure Incentive Policies

MECHANISM ➔ PARAMETERS↓	1A - SOLAR QO WITH TRADABLE SRECS	1B - SOLAR QO WITH TRADABLE SRECS + PRICE FLOOR	2A - AUCTION FOR LT CONTRACTS	2B - CENTRAL PROCURE-MENT	3 - STANDARD OFFER PBI	4 - STANDARD OFFER REBATE
Owner's Transaction Costs	Lower transaction costs than competitive bid But participants must regularly market and contract RECs	Lower transaction costs than competitive bid But participants must regularly market and contract RECs	Transaction cost and development risk may be a prohibitive barrier to smaller generators	Transaction cost and development risk may be a prohibitive barrier to smaller generators	Significantly reduced transaction costs and development risk compared to tenders	Reduced transaction costs and development risk compared to tenders

10.3. Selected Policy Options

Four policy mechanisms were selected for detailed analysis. Two of the policy mechanisms were selected from the pure policy mechanisms described in the prior section and applied to all installation types (uniform policy mechanisms), while two approaches were crafted by applying different pure policy mechanisms to different types of installations (hybrid policy mechanisms). These alternatives were selected to illustrate an expansive range of available policy mechanisms and test their relative cost as well as the implications of some of their distinguishing features. In line with the policy objectives and evaluation criteria disused in Section 1.3, these policy mechanisms were also selected based on a qualitative assessment of:

- Their potential to minimize ratepayer cost. Use of a pure SREC quantity obligation without mechanisms to provide revenue stability was ruled out because of the mechanism's expected higher cost, difficulty in supporting project financing, and market volatility
- The presence or absence of substantial transaction costs. As observed in Chapter 9 and Section 10.2.2.3, direct participation in competitive procurements is disproportionately onerous and costly for smaller systems particularly from a transaction cost perspective. As a result, hybrid approaches were considered in which smaller systems would be able to access incentives without facing the disproportionately high cost of competition

- Their use of market-based mechanisms that could provide market price signals, consistent with New York's deregulated market. A pure up-front incentive approach applied across all installation types was ruled out because it would not rely at all on competitive market mechanisms.

After selection, minor modifications to the policies described in sections 10.2.2 and 10.2.2.3 were made to further illustrate potentially distinguishing features of the policies.

10.3.1.1. Uniform Policy Mechanisms Analyzed

The first two policy mechanisms selected for analysis would apply to solar installations across the full range of project sizes. The third and fourth policy options described below represent hybrids that apply different approaches for smaller and larger solar installations, in light of the specific strengths and limitations of each policy approach described in Section 9.3.3.7. The policies selected include:

- ***Solar Quantity Obligation Using Tradable SRECs, with a Price Floor Mechanism*** (Policy 1b, referred to hereafter as "***Solar QO with Price Floor***"). This choice was selected because of its similarity to the approaches adopted in neighboring states with aggressive solar policies, New Jersey and Massachusetts.[142]
- ***An Auction for Long-Term Contracts by the electric distribution companies*** (EDCs) (a special case of Policy 2a, referred to hereafter as "***EDC Long-term Contract Auction***"). This choice was selected to explore the implications of using competitive mechanisms that support project financing through the use of long-term contracts. A competitive auction approach for renewable energy up to 20 MW (including PV) was recently adopted in California.[143]

10.3.1.2. Hybrid Policy Mechanisms Analyzed

In practice, many jurisdictions – including New York -- have utilized several different policies concurrently in order to achieve different objectives, address gaps in the market, support specific segments of the value chain, etc. Internationally, the only three countries that use only one renewable energy policy are Algeria, Serbia, and Sri Lanka (REN21, 2011). Mechanisms currently in use in New York combine strengths of different mechanisms and/or avoid some of the limitations presented by other policy mechanisms. For example, the New York regional competitive bidding PV incentive program offers a combination of partial up-front payments and performance based incentives awarded through a competitive bidding process. .

There are many different ways that policies can be combined. Some jurisdictions implement different policies in parallel, whereas others develop innovative methods of combining previously distinct policy mechanisms and blurring the lines between well-established policy labels. The New York Solar Jobs Act of

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[142] Both New Jersey and Massachusetts have adopted aspects of solar policy support which only apply to certain project sizes, while the policy examined here, for illustrative purposes, would apply across the board.

[143] The first auction closed on November 15th, 2011 and winners will be announced at the end of January 2012. *See http://www.cpuc.ca.gov/PUC/energy/Renewables/hot/Renewable+Auction+Mechanism.htm*

2011[144], for example, proposed developing a PV policy that would utilize several different types of mechanisms to procure solar RECs. Under the bill, distribution companies, LIPA, and NYPA would each be required to develop solar procurement plans to meet solar electricity targets of 1.5%, 2%, and 2%, respectively, by 2020. The bill specifies that minimum percentages of certain system types must be procured using different mechanisms. Small (< 50 kW), behind-the-meter systems must comprise 20% of the procured solar electricity and must be procured using standard offers for SRECs using administratively determined prices.

The bill specifies that SRECs from behind-the-meter systems over 50 kW must comprise 30% of total annual procurement, but that two different procurement mechanism must be utilized depending on the system size: SRECs from systems over 250 kW are procured through competitive solicitations, whereas systems between 50 kW and 250 kW receive a standard offer payment that is set based on the results of > 250 kW competitive solicitation. The bill does not specify the type of procurement for larger projects and, therefore, a variety of different types of competitive procurement mechanisms could be employed. The law also applies to competitive electricity suppliers[145] but does not specify the types of PV systems that must be procured or the procurement methods that must be used.

For the purpose of this study, two hybrid policies were considered, applying different policy mechanisms in parallel to support smaller generators (consisting of residential and small commercial installations) and larger generators (consisting of large commercial and industrial, as well as megawatt-scale ground mounted systems). The hybrid policies have been selected to reflect the fact that smaller generators face significant transaction costs to participating in competitive incentive programs, whereas larger-scale systems are better positioned to compete. Table 81 below contains a high level overview of the different hybrid paths.

144 There are two different versions of the New York State Jobs Act of 2011, Assembly Bill 5713 (Englebright) and Senate Bill 4178 (Maziarz). This discussion refers to Assembly Bill 5713.

145 Retail electricity suppliers that are not distribution companies, also known as energy service companies or ESCOs.

Table 81. Hybrid Policy Options

	HYBRID A	HYBRID B
Benchmarks (i.e., similar policies or policy elements)	Similar to current NY approach, except that the Main Tier is currently not differentiated for PV	Similar to NY Solar Jobs Act, A05713 (2011)[146] (key difference, this bill would use auction results to set mid-sized Std Offers)
Smaller Generators	Upfront Incentives	Standard offer PBIs
Larger Generators	Central procurement (RFP or tender)	Auction for long-term contracts

Up-front incentives and standard offer PBIs and have been applied to the residential and small C&I market segments because they minimize development risk and transaction costs. The benefits and drawbacks of each tier of the hybrid policy models are consistent with those outlined in Section 10.2.2 for the corresponding pure policies. The hybrids selected for further modeling[147] include:

- ***Upfront Incentives for Residential and Small C&I installations and extension of the New York Main Tier Central Procurement approach to Large C&I and MW-Scale installations*** (referred to hereafter as "***Hybrid A***" or "***Upfront Incentive/Central Procurement Hybrid***"). This hybrid approach is one way to extend and target New York's current renewable energy policy support approach to meet the proposed solar targets.
- ***Standard Offer PBIs for Residential and Small C&I installations and Auctions for Long-Term Contracts for Large C&I and MW-Scale installations*** (referred to hereafter as "***Hybrid B***" or "***Standard Offer/Auction Hybrid***"). This hybrid approach is similar to recently proposed PV policy legislation in New York[148], which should reduce investor risk and owner's transaction costs creating one of the least-cost implementation approaches for smaller and larger solar installations, respectively.

10.4. Modeling Characterization of Selected Policy Options

For each of the policies selected for analysis, cross-cutting additional design parameters are defined below for use in estimating policy costs. Additional design details for each policy mechanism are described in Appendix 12. Modeling characteristics have been defined based on benchmarking other successful policies and best practices. The detailed modeling assumptions are then summarized, followed by a discussion of how the modeling characteristics were determined for each policy.

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146 Key differences between the New York Solar Jobs Act of 2011 (S.4178 & A.5713) and the Hybrid B approach analyzed here include (i) the NY Solar Jobs Act would use auction results to set Standard Offer PBIs for mid-sized installations, and only SRECs would be procured.

147 An alternative approach would be to continue the residential up-front incentive program and extend the regional competitive bidding PV incentive program to the entire state.

148 The New York Solar Jobs Act of 2011 (S.4178 & A.5713)

10.4.1 Cross-Cutting Assumptions

Specific design choices could be applied to different policy mechanisms to make them more or less alike. In order to focus this analysis on the differences between fundamental characteristics of each selected policy mechanism, rather than specific design choices that could be applied to each policy mechanism, common approaches were applied where applicable to addressing electricity market revenue risk and policy durations. These assumptions are spelled out in the following two subsections.

10.4.1.1. Addressing Electricity Market Price Risk for Modeling

The degree of electricity market revenue risk to which a system owner is exposed impacts the LCOE required to attract investment, either through the cost of capital (the more risk, the higher the cost of capital), additional costs associated with hedging the risk, or discounting the assumed future electricity revenues to reflect the uncertainty when projecting investment rates of return. For generation sold to the grid, this risk reflects the exposure of a system owner to uncertain future revenues. While there are means to at least partially hedge such revenues through long-term contracting or use of derivatives, these options have limited availability, imperfect correlation to the local price of electricity, high cost, or credit requirements making them largely inaccessible to many system owners. For PV generation used behind-the-meter, either directly or financially via net metering, the value of the energy is tied to the cost of electricity retail costs avoided. The underlying risk of uncertain future revenues is analogous to that of electricity sold to the grid.

For each policy selected for modeling, other than the upfront incentives, design choices impact the degree of electricity market revenue risk. As noted above, in order to focus on the differences between fundamental characteristics of each selected policy, a common approach to addressing electricity market revenue risk was adopted. This approach is referred to herein as a ***Variable Indexed Market Gap (VIMG)*** approach**.** It is analogous to the variable-premium, spot market gap pricing structure used in some standard offer PBIs.[149]

The VIMG approach is a variable incentive structure, where the payment for each MWh produced is calculated as the difference between (i) a specified fixed price and (ii) a variable component indexed to the annual, production-weighted market value of either wholesale electricity or avoided retail electricity purchases, as applicable. In order to simplify administration and provide generators with the proper incentive to maximize their production (particularly at peak times), the variable component would be independent of the production of any particular solar installation, instead calculated based on a theoretical standard expected production profile appropriate to a location (influencing the amount of sunlight) and other size-appropriate standard performance characteristics (such as tilt, orientation, inverter efficiency,

149 See Appendix 2, Section A2.3, Standard Offer PBI Framework.

soiling, etc.). For example, a VIMG-based payment for an installation with LCOE of $350/MWh and a average market value of $100/MWh would be $250/MWh.

The VIMG approach creates a comparable degree of electricity market revenue risk to system owners across system sizes and policies. It also imparts the minimum degree of electricity market revenue risk possible, comparable to a situation in which the system owners were guaranteed a fixed revenue for SRECs and electricity (aside from deviations of a specific system's performance from the standard system assumed described below). Any variation from this approach, such as utilization of fixed price contracts for SRECs, would increase the market price risk exposure of system investors resulting in a higher LCOE than used in this study.

For each of the long-term contract approaches – involving auctions, central procurements or standard offers - the payment for SRECs in each year would be indexed in this manner. For the Solar QO with Price Floor policy, the price floor would be set on a VIMG basis.

10.4.1.2. Policy Duration

For all policies mechanisms other than the up-front incentive, it was assumed that the duration of policy support was held constant across policies at 25 years, the assumed economic life of PV systems used in calculating the LCOEs in Chapter 4. Keeping the duration consistent between policies focuses the cost analysis on the differences between fundamental characteristics of each selected policy rather than design choices that could be applied to each policy. Use of long-term contracts – in this study, 25 years – minimizes market revenue risk for system investors. A shorter duration of policy support would likely front-load the rate impact and increase the LCOEs due to both a shorter period over which fixed costs can be spread, as well as increased market revenue risk.

10.4.2 Selected Policy Modeling Assumptions

This section discusses how the features of different policy choices selected for modeling will impact the cost of energy projection. It also describes how issues such as transaction costs and administrative costs are addressed in the modeling.

Each policy would be expected to have somewhat different direct costs premiums, administrative and transaction costs. Policies may also be designed to stimulate different size or geographic installations deployments. The following subsections describe modeling assumptions pertaining to the cost premium, administrative cost, transaction cost, and deployments for each policy.

Some of the differences between policies are subtle and depend on more detailed policy design choices than are made in this study. For some factors, the cost impact is small relative to the overall policy costs.

For other factors, such as administrative and transaction costs, there is limited data to enable comparisons across different policy types. In either case, explicit estimates of cost differences among the four policies are addressed qualitatively; while beyond the scope of this study, these factors merit further research and analysis.

10.4.2.1. Policy Mechanism Cost Premium

The potential differences in direct cost premiums among policies are driven by differences in:

- the cost of financing, which reflects risk allocation and the degree of process and contract standardization under each policy
- avoided developer costs afforded by the certainty of access to incentives and certainty of timing inherent in standard offers (e.g. either PBIs or upfront incentives)
- the timing of incentives, and
- costs associated with the market price risk borne by system owners, including costs incurred to hedge such risk or the risk premium built into the financial forecasts of system investors.

The assumed use of a VIMG pricing approach described in Section 10.4.1.1 mitigates most of the market risk associated with exposure to unhedged electricity revenues and therefore removes (from a modeling perspective) the potential differences between policies that include fixed price purchases of electricity, and those that do not. This simplifying assumption allows for variation in the cost of financing to be used as the lever for varying the differences in projected policy cost.

Chapter 4 projects the long-term trend of levelized cost of energy (LCOE) of solar, for four standard installations sizes and different locations throughout New York[150]. For purposes of comparing the cost of the four policy mechanisms described herein, the Base assumptions for installed cost and Federal incentives assumptions described in Chapter 4 are held constant. The financing assumptions underlying the Base LCOE are consistent with both the *EDC Long-Term Contract Auction* policy and the *RPS Central Procurement* portion of the *Upfront Incentive/Central Procurement Hybrid,* and are used as the basis for projecting the costs of those incentives. The costs of policy incentives for the other policies are varied from the Base LCOE as appropriate to reflect differences in investor risk, developer costs, and incentive timing from the Base. The specific modeling approached and their rationale are laid out below in Table 82, and the specific financing assumptions used are shown in Table 83, below.

150 Developed in Chapter 3.

Table 82. Quantitative Modeling Assumptions for Cost of Policy Incentive Premium

POLICY		MODELING ASSUMPTION	RATIONALE
Solar QO with Price Floor		Use 25-yr LCOE calculated using equity finance costs higher than 'base' finance case by 2%	Market price risk remains on owner for revenues over the floor price. Assume debt sizes itself to the floor, which is assumed to be as credit-worthy and reliable as a long-term contract (so cost of debt remains the same); equity bears the price risk above the floor.
EDC Long-Term Contract Auction		Use 25-yr "Base" LCOE; Assume LCOEs represent average price under an as-bid auction.	VIMG Pricing Structure eliminates price risk, contract duration matches assumed project life. Assume prices are differentiated but closely clustered within each tier of location and size.
<u>Upfront Incentive</u>, Central Procurement Hybrid	<u>Upfront Incentive</u>	Calculates the upfront incentive necessary to reach target investor returns as the net present value of the cost premium of LCOE over the market value of electricity produced, assuming 25-yr "Base" LCOE, and using the "Base" equity cost of capital as the discount rate.	Using the equity discount rate calculates the point of indifference between a contract and a upfront incentive to an investor exposed to consistent market revenue risk.[151] Electricity market price risk remains with the system owner, which would be likely to increase the required incentive for investor indifference between a upfront incentive and a fixed-revenue over the project life. Nevertheless, an upfront incentive removes some or all of the performance risk, and the standard offer nature of the upfront incentive avoids some of the developer costs associated with competing for long-term contracts. These impacts are assumed to offset.
	Central Procurement	Uses 25-yr "Base" LCOE. Assume LCOEs represent average price under an as-bid auction.	VIMG Pricing Structure eliminates price risk, contract duration matches assumed project life. Assume prices are differentiated but closely clustered within each tier of location and size.
Standard Offer PBI, Auction Hybrid	Standard Offer performance-based incentive	Uses 25-yr LCOE calculated using cost of equity by 2% below that 'base' finance case	VIMG Pricing Structure eliminates price risk, contract duration matches assumed project life. Reduced equity cost is used as a proxy to capture both a lower cost of equity capital due to the nature of programmatic policy certainty, as well as avoided developer costs.[152] The differences from the "base" policy case occur prior to permanent financing, and therefore would manifest itself in cost of equity capital.
	Auction	See EDC Long-Term Contract Auction above	

151 The authors tested several sample installations using the CREST model described in Chapter 5, using a range of estimated market value assumptions, and found the incentive calculated in this manner came within a few percent of yielding the equivalent IRR, after reoptimizing the financial structure to reflect reduced system installed cost.

152 See discussion on Timing of Revenue and Access Certainty in Section 9.3.3.6.

Table 83. Financing Assumptions for Selected Policies

FINANCING ASSUMPTION	UNITS	RESIDENTIAL	SMALL C&I	LARGE C&I	MW-SCALE
Select Financing Assumptions for EDC Long-Term Contract Auction, Central Procurement, and Upfront Incentives					
Permanent Financing					
Debt/Equity Ratio	%	50/50	50/50	50/50	50/50
Debt Term	Years	15	15	15	15
Interest Rate (Annual)	%	6%	6%	6%	6%
Target After-Tax Equity IRR	%	12%	12%	12%	12%
Target After-Tax Equity IRR (Cost of Equity) for Other Policies (all other financing assumptions held constant)					
Solar QO with Price Floor	%	14%	14%	14%	14%
Standard Offer PBI	%	10%	10%	10%	10%

10.4.2.2. Administrative Costs

As described in Appendix 3, there is limited directly applicable available data on the comparative administrative costs of the policies selected for further examination. Detailed cost estimates would require a detailed operational plan, which is beyond the scope of this study. For purposes of this modeling study, it is assumed that administrative costs associated with each policy are of a similar order of magnitude to one another. A proxy for administrative costs is assumed as 3% of the total policy premium, based on a benchmark of 2011 NYSERDA RPS administrative costs of approximately 3.3% of outlays (NYSERDA, 2011e). It is expected that a program with many, small-MW contracts would require a more administrative support, but this approach was used to simplify the analysis given the uncertainty in actual contract size.

Qualitatively, it is expected that the policies selected for further examination would have somewhat lower, similar or somewhat higher administrative costs, as follows:

- The ***Solar QO with Price Floor*** is expected to have lower administrative costs than the 3% benchmark. While it avoids the need for (and costs associated with) competitive bidding, program management costs would reside with whatever entity provides the price floor. One point of comparison for this policy is the Massachusetts floor price auction. This auction charges a 5% administrative fee to cover the cost of running the floor price auction; however, the auction would only be run in years in which supply surpluses exist. If auctions were run less than half of the years and this cost was representative, costs would be lower than the 3% benchmark. Still, because there is so little experience with operating a successful price floor mechanism at scale, estimating the transaction costs is speculative without a detailed policy design and accompanying operating experience

- ***EDC Long-Term Contract Auction:*** It is expected that this program would have costs similar to, but somewhat higher than, the NYSERDA RPS Central Procurement. While the functions would be similar, because the EDCs would operate the auctions, each EDC would need to create new systems and build internal management capacity
- ***Upfront Incentive/Central Procurement Hybrid****:* This policy most nearly replicates the current NYSERDA RPS approach and therefore scaling it up to a larger number of transactions would be expected to have similar transaction costs to the benchmark
- ***Standard Offer/Auction Hybrid****:* The standard offer component would be expected to avoid some of the costs associated with competitive procurement. Still, potential additional costs would arise relative to the rate setting process (likely modest after an initial more complex setup stage), as well as perhaps operating and maintaining a queue of eligible projects. If offered by NYSERDA, costs would likely be similar to running the CST program.

10.4.2.3. Transaction Costs

Owner transaction costs are generally modest compared to the scale of the solar policy premium, particularly at current PV costs. Nevertheless, the presence of transaction cost economies of scale is well-understood: transaction costs associated with some policies can be prohibitive for small-scale installations. Costs of bidding and contracting do not scale with the size of a PV system (i.e. transaction costs for a 6 kW system are not twice the transaction costs associated with a 3 kW system). Perhaps the most extreme example would be the transaction cost associated with responding to a central procurement request for proposals that required completion of a benefits report and associated verification protocol, which would be disproportionately high for small systems.

The nature of transaction costs and their relative magnitude are discussed in Section 10.2.2.3. The presence or absence of substantial transaction costs is one of the factors driving the selection of policies chosen for detailed analysis. For instance, it is expected that performance-based standard offers and up-front standard offers incentives will have substantially lower transaction costs than alternatives requiring bidding and contract negotiation. This expectation supports the selection of the two hybrid approaches for exploration: standard offer performance-based incentives and upfront incentives for small customers, and approaches such as participation in auctions or central procurement are targeted at larger installations where transaction costs represent a smaller proportion of overall costs. Qualitatively, transaction cost expectations among the policies selected for further analysis can be expected to possess the following general characteristics:

- For the Solar QO with Price Floor: the need to regularly market and contract RECs on a short-term basis suggests that owner transaction costs would be substantially higher than other options under which a single contract may be required. Depending on how the price floor is established, additional transaction costs could be involved

- Under the Standard Offer performance-based incentive and upfront incentives, system owners would not have to incur some costs and risks associated with bidding or contracting under competitive auctions or central procurement.

Data is available to estimate transaction costs for selling SRECs in quantity obligation markets.[153] Nevertheless, available data to estimate the transaction costs borne by PV system owners under other policy options is quite limited. Further, policy implementation design choices can impact transaction costs. For example, while costs to participate in an auction may be proportionately high for small system, allowing aggregators (installers, lease-holders, brokers, etc.) to participate in the auction can allow smaller systems to participate on a more level playing field with larger installations. Similarly, policymakers could implement competitive procurements on a simple price basis, or require substantial additional documentation. As a result, differentiated transaction costs among policies were not estimated for purposes of this study. If and when a policy is selected for further study or implementation, approaches which seek to minimize transaction costs can be subjected to further study.

10.4.2.4. Deployment

Design choices can be used to stimulate particular deployments. For purposes of this analysis, design choices have been assumed to stimulate a common distribution of installation sizes and locations, described as the *Base PV Scenario* in Chapter 3. As discussed in the section describing each policy, each policy other than the *Solar QO with Price Floor* can be designed to demand a particular distribution. In a quantity obligation policy structure where generators compete across the entire state on a price basis, it would be difficult in practice to predetermine a specific geographic or size distribution. As a simplifying assumption, the *Solar QO with Price Floor* policy assumed differentiated price floors to make projects viable over range of sizes and locations, thereby incentivizing a similar distribution.

Chapter 4 also describes two alternative deployment scenarios, one tilted more toward urban and distributed generation installations, and the other towards larger-scale installations capable of achieving greater scale economies. The cost impact of designing policies to achieve these different geographic and size distributions is tested in the sensitivity analysis described in Chapter 5 (Benefits and Cost) and Chapter 7 (Rate Impacts).

10.5. Comparison of Policy Mechanism Rate Impacts

The overall net ratepayer impact of the four policy mechanisms modeled is shown in Figure 55. The direct and net rate impacts, as a percentage of total retail rate revenue, are shown in

153 See for example the transaction fees charged by entities such as SREC Trade (http://www.flettexchange.com/index.php?page=fees) or Flett Exchange (http://www.srectrade.com/srectrade_brokerage.pdf).

Figure 56 and Figure 57, respectively. The direct rate impacts show the front loading associated with the upfront payment component of Hybrid A. The net-rate impacts show that a small (<0.5%) rate reduction is realized due to the price suppression benefits; however, these rate reductions are short lived and are dwarfed by the rate increases between 2019 and 2049. The net-rate increases in all cases are less than or equal to 3% of total annual revenue over the entire study period, where the net-rate increase for Hybrid A is approximately equal to or less than 2% of total annual revenue.[154]

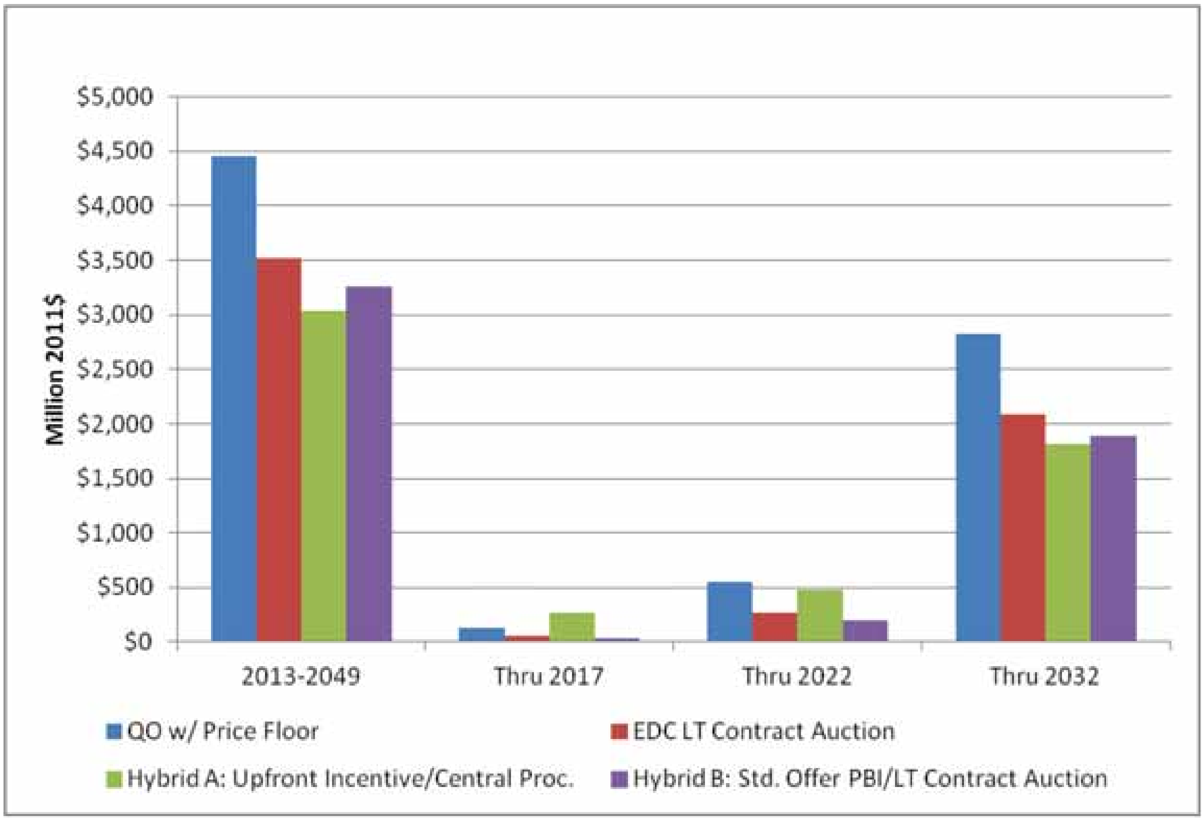

Figure 55. Comparison of Net Policy Options Rate Impacts

154 The four selected policy mechanisms were not modeled under Low PV Cost or High PV Cost futures. The general relationship between the Base PV Scenario and the Low PV and High PV Cost sensitivities would be expected for each policy mechanism under different cost futures.

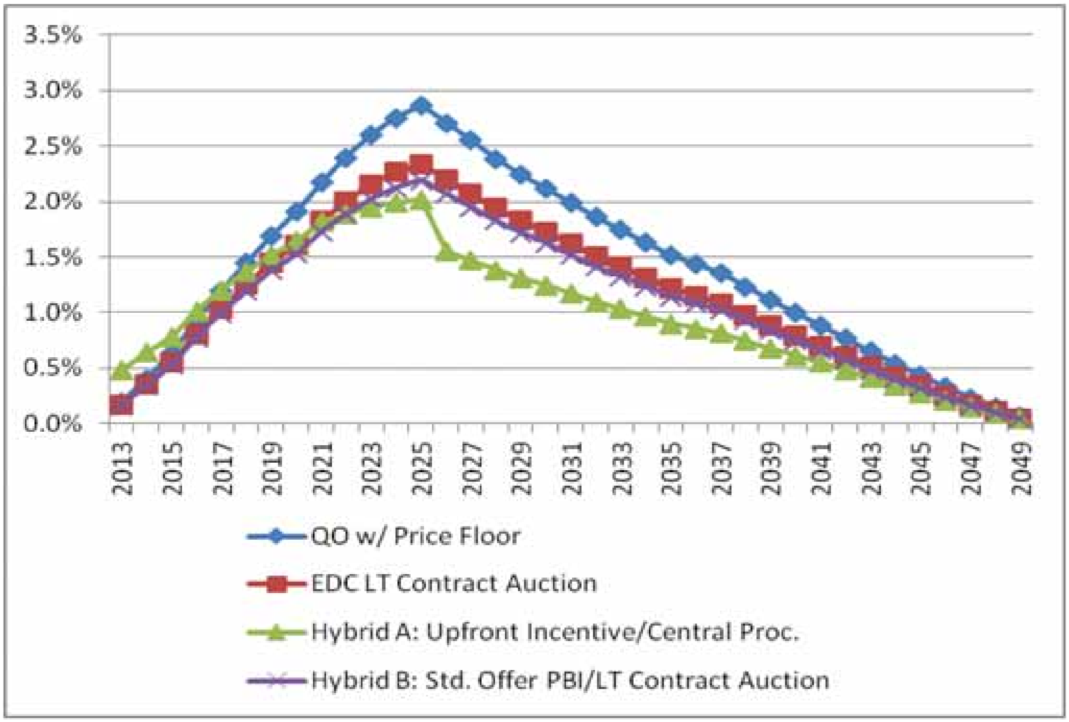

Figure 56. Direct Rate Impact as a Percentage of Total Bill by Policy Mechanism, 2013-2049

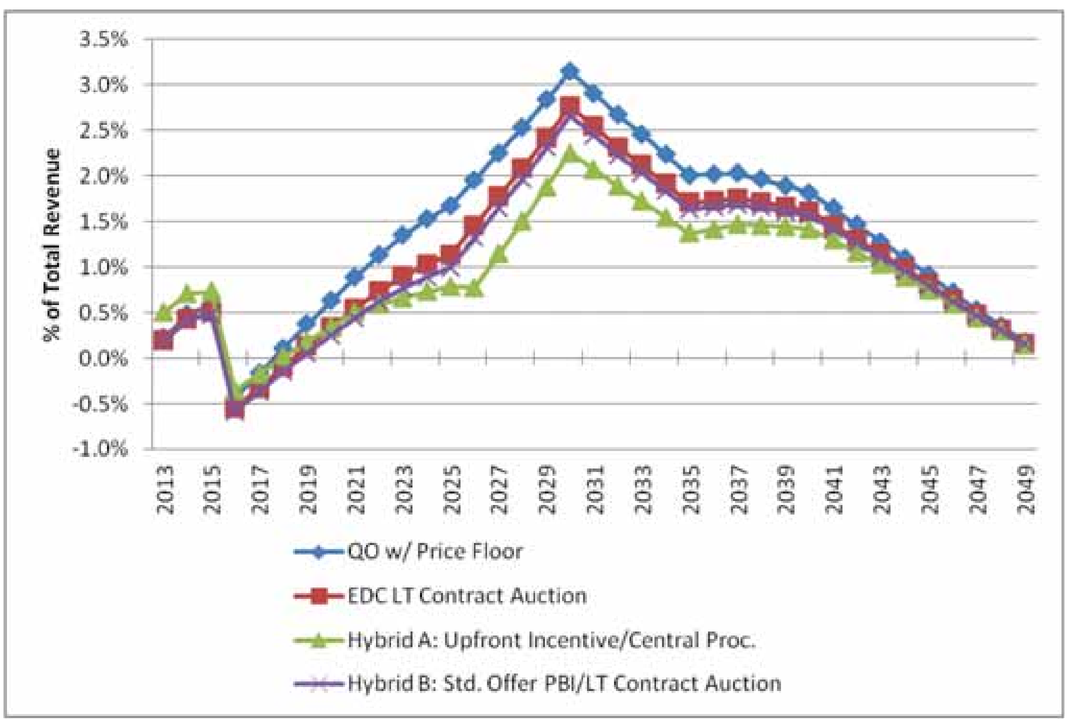

Figure 57. Net Rate Impact as a Percentage of Total Bill, by Policy Mechanism, 2013 - 2049

Table 84 shows a summary of net ratepayer impact results for the four policy mechanisms.[155] These results show that the QO with price floor is expected to be the most expensive of the policy mechanisms considered, costing $ 1.5 billion (or 50%) more on an NPV-basis than the least-cost policy mechanism. Hybrid A, with upfront incentives for small customers and central procurement for large customers, is least expensive on an NPV basis, although due to the upfront-incentive payment timing it is more front-loaded and has higher net rate impact in the early years of the policy horizon. Hybrid A is followed closely by Hybrid B, with a Standard Offer PBI for small customers and long-term contract auction for large customers, and the EDC long-term contract auction case for all customers. The ratepayer cost of the latter three policy mechanisms is close, suggesting that a choice among them may be influenced by consideration of other factors such as design details, administrative costs, compatibility with the New York market, or implementation challenges discussed in this chapter and the accompanying appendix.

The primary driver of differences among the project rate impact resulting from four the different policy mechanisms analyzed is the differing degrees of risk to PV system investors and therefore different required returns for equity financers discussed in this chapter. While the overall magnitude of rate impact differences among policies is lower than the impact of future PV cost or deployment choices, the choice of policy mechanism can make a significant difference in the cost of the policy. Considering net ratepayer impact, Table 84 shows that the QO with price floor is projected to cost 50% more than the least cost option. The difference among the other three policy mechanisms is much smaller, less than 17%. The magnitude of difference is potentially smaller than the impact of specific design choices including targeting deployment to specific installation types and locations. In addition, in this range of differences, tradeoffs among the policies' performance relative to other objectives (e.g. implementation challenges, transaction costs, fit with market structure) may influence the choice of one policy mechanism over another.

Table 84. Comparative Net Ratepayer Impact of Policy Mechanisms Using Base PV Cost

Policy Mechanism	Net Ratepayer Impact 2013-2059 (NPV 2011$)	% of Total Rates	Net Ratepayer Impact % of Least Cost Mechanism
QO w/ Price Floor	4,500	1.23%	150%
EDC LT Contract Auction	3,500	0.97%	117%
Hybrid A: Upfront Incentive/Central Proc.	3,000	0.84%	100%
Hybrid B: Std. Offer PBI/LT Contract Auction	3,300	0.90%	110%

Direct rate impacts peak in 2025 when all the PV installations projected to reach 5000 MW PV for this study have been installed, and decline thereafter driven by a combination of decreasing cost premiums over

155 Detailed results are shown in Appendix 13.

time (as the market value of PV production rises) and PV system retirements. This shape is somewhat an artifact of the boundary conditions of this study, as described in Section 1.2.1, that is, that no additional PV systems were assumed to be installed after reaching 2025 and no replacements of systems after their assumed 25 year economic life occurred. As shown in the discussion of retail rate parity in Section 3.8, by 2025 PV installations in some regions and some sizes are reaching parity with retail rates, particularly in the New York City and Long Island regions. In the Low Cost PV future, such rate retail parity occurs as early as 2017 in New York City. For installations having reached rate parity, assuming continuation of net metering policies, direct rate impacts of additional installations or replacements would impose no further direct rate impact, while for other locations the magnitude or retail rate impacts thereafter would be shrinking and eventually disappear. PV installations in other regions may not reach retail parity without continuing declines in PV costs, but would have their rate premiums disappear if and when PC cost levels indicated in the Low PV Cost Future were reached. The magnitude of required upfront incentive for small customers in Hybrid B illustrates these points. As shown in Table 85, the required upfront incentive under Base PV Costs approaches zero by 2025 in NYC and Long Island regions, while in the Upstate region the incentive is still approximately $1 per Watt.

Table 85. Residential Upfront Incentive Payment, Base PV Costs, $/W (nominal)

Location	2015	2020	2025
Upstate	$1.89	$1.56	$1.02
Capital	$1.77	$1.41	$0.87
Downstate	$1.39	$1.03	$0.50
NYC	$1.21	$0.67	$0.09
Long Island	$1.01	$0.60	$0.14

As with the net ratepayer impacts for the Base PV Scenario described in Chapter 7, net rate impact peaks for each policy mechanism in 2029 due to strong wholesale price suppression impacts in the years prior to 2029.

11. CONCLUSION

11.1. INTRODUCTION

The *Power New York Act of 2011* directed NYSERDA to conduct a study regarding policy options that could be used to achieve 2,500 MW PV installations operating in New York State by 2020 and 5,000 MW operating by 2025. The Act required NYSERDA to identify administrative and policy options to meet these targets, estimate the costs, the net economic and job creation benefits, and the environmental benefits of meeting these targets.

This chapter synthesizes the Solar Study's analysis of a PV policy meeting the targets of the Act – the Base PV Scenario, covering direct costs and benefits, net jobs and macroeconomic impacts, retail rate impacts, and environmental impacts. It summarizes analyses testing the sensitivity of those results to key drivers such as alternative PV cost futures, alternative geographic deployments, higher energy prices, and the continued operation of Indian Point. It also summarizes the cost implications of four alternative policy mechanisms identified and recommended for consideration as means to meet the Act's objectives.

A series of evaluation criteria and associated metrics were developed in order to evaluate and compare the scenarios and sensitivities studied. Evaluation criteria measure the effectiveness of a policy at achieving applicable policy objectives.[156] The results are summarized according to metrics and evaluation criteria that align with the policy objectives identified in Chapter 1 as potentially relevant to policymakers' consideration of PV policy approaches to meeting the targets described in the Act. These policy objectives are repeated in Table 86, below. Results (both qualitative and quantitative) are discussed below by objective type. Quantitative results are summarized in tables that show cumulative impacts over the full study period of 2013-2049.[157] This evaluation highlights the inherent tradeoffs in pursuing policies to substantially increase the penetration of PV systems in New York State, as well as among different policies capable of achieving the goals.

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156 Evaluation criteria come into play in two portions of the Study: guiding the selection of policy mechanisms to study, and evaluating the scenarios and policy mechanisms analyzed. Evaluation criteria discussed in this chapter are based upon, and reflect, the distinguishing objectives as discussed in Chapter 1. Each quantifiable evaluation criterion has associated metrics, the measurable characteristics used to assess the effectiveness of a policy at meeting the associated objectives. For example, if minimizing cost to ratepayers is an objective, a relevant evaluation criterion is minimizing the net ratepayer costs relative to the reference case, and the associated metric would be NPV of ratepayer impacts. Quantifying some potential policy evaluation criteria is beyond the scope of this study.

157 Summaries of cumulative impacts over the first five years (2013-2017), over the first 10 years (2013-2022), and over the first 20 years (2013-2022), can be found in the individual appendices.

Table 86. Potential Driving Policy Objectives for PV

Category	Policy Objectives
Environmental	• Minimize greenhouse gas emissions • Minimize criteria pollutant, mercury and other air pollution emissions • Reduce impacts related to water use in thermal electric generation (thermal, quality, quantity) • Preservation of land from fuel cycle impacts (mining, drilling, etc.) • Minimize use of land with higher value alternative uses • Reduce reliance on finite fossil fuels
Energy Security and Independence	• Increase fuel diversity • Increase energy security and supply reliability • Increase domestic energy production
Reliability	• Reduce electric delivery disruption risk • Minimize negative grid planning and operating reserve impacts • Minimize distribution system negative reliability impacts (avoiding degradation of system loss of load probability)
Economic Development	• Maximize net in-state job creation • Maximize gross state product (GSP) growth • Support existing clean technology industries • Minimize out-of-state capital flows • Create stable business planning environment (for supply chain investment)
Energy Cost	• Defer or reduce distribution system upgrades, and minimize additional upgrades caused by PV • Reduce wholesale prices (energy and capacity impacts) • Minimize direct cost of policy to ratepayers • Minimize total cost of policy (exclusive of monetizing environmental, public health or other impacts) • Integrate well with competitive retail market structure in NY • Integrate well with competitive wholesale market structure in NY
Technology Policy	• Create a self-sustaining solar market • Assist emerging technologies in becoming commercial technologies • Foster technology innovation & development
Societal	• Ensure geographic distributional equity/effectiveness at aligning benefits with those who bear the costs • Maximize benefits to environmental justice communities

Section 11.2 presents a summary evaluation of results for the Base PV Scenario. Section 11.3 presents a comparison of the alternative policy mechanisms identified for further consideration to meet the targets of the Act. Section 11.4 summarizes the results of the sensitivity analyses. In Section 11.5, the studies key findings are summarized.

Finally, many questions were inevitably raised in the course of an investigation that are beyond the scope of the study. Section 11.6 identifies future research needs identified throughout the study as beyond the scope of this study but meriting attention.

Interpretation of costs, benefits and impacts can vary depending on the perspectives considered. What may be a cost to one party may be a benefit to another. Costs and benefits look different if considered through the eyes of different stakeholders. The PV market has a diverse set of actors with potentially unique perspectives. Equity investors, commercial lenders, electric distribution companies, electricity generators, PV manufacturers, installers, system owners, site hosts, ratepayers and "society" all have potentially competing perspectives on the most appropriate solar incentive policy. This study has identified and measured impacts from different perspectives where applicable.

Three different discount rates were selected to reflect different perspectives from which the results can be assessed. Monetary metrics on a net present value (NPV) basis in 2011 dollars were developed using a nominal 7.0% discount rate (which corresponding to a real discount rate of 5.1%). Interested readers can review the appendices, where NPVs are also shown using a lower discount rate of 4.35% and a higher discount rate of 12%. The discount rate sensitivity reveals that while the magnitude of results will of course vary, the relative positioning and direction of the conclusions presented here is not highly sensitive to the discount rate selected. For example, changes in discount rate did not significantly change the cost and benefit results for the Base PV Scenario.

11.2. Evaluation of Base PV Scenario Results

11.2.1 Environmental Objectives

Any PV policy adopted to meet the targets in the Act will have environmental benefits and impacts, including reductions in emissions of greenhouse gases, criteria pollutants, mercury and other air pollutants, reductions in fossil fuel use, and land use impacts (when PV installations utilize green field sites). Each of these impacts was quantified and summarized in Table 87 below. These impacts are the same for all sensitivities and policy mechanisms studied, with the exception of alternative PV deployments summarized in Section 11.4 below. PV installations would also reduce water use in thermal electric generation, thereby reducing thermal pollution and water quality impacts, and decrease the fuel cycle impacts of fossil fuels displaces (e.g. mining, drilling, etc.). Analysis of these impacts is beyond the scope of this study.

Table 87. Environmental Impacts Base PV Scenario

		Base Deployment
Criteria	**Metric (units)**	**2013-2049**
CO_2 Reduction	(M Tons of CO_2)	(47)
CO_2 Reduction Benefit @ $15/ton	(NPV M 2011$)	(460)
CO_2 Reduction Benefit @ $107/ton	(NPV M 2011$)	(3,200)
Criteria Pollution Reduction	(Tons of SO_2)	(67,000)
	(Tons of NO_x)	(33,000)
	(Pounds of Mercury)	(120)
Criteria Pollution Reduction Benefits	(NPV M 2011$)	(33,000)
Reduction in Fossil Fuel Consumption	(TBtu)	(1,100)
Minimize Land Use	(Greenfield Acres)	3,000

11.2.2 Energy Security and Independence Objectives

Policies that support increased PV deployment serve to meet important energy security and independence objectives by having the following impacts:

- Increasing fuel diversity by displacing fossil fuel generation (coal, gas, and oil) that have dominated New York's fuel mix
- Increasing energy security and supply reliability due to its location closer to load sources and behind-the-meter
- Increased energy price stability due its lack of reliance on volatile fossil fuels.

Table 88 shows the fossil fuel reduction impacts associated with the Base PV Scenario. There is material difference among the cases analyzed with respect to the magnitude of these impacts. Quantification of other impacts is beyond the scope of this study.

Table 88. Projected Reductions in Fossil Fuel Consumption from PV Generation in 2025

Fuel type	Amount consumed in 2025 (TBtus)	Fuel displaced by PV in 2025 (TBtus)	% reduction in fuel consumption in 2025
Coal	110	8	7%
Natural gas	460	20	4%
Oil	2	0.80	38%

11.2.3 Reliability Objectives

Related to the objectives of the prior section, PV installations can also serve to increase reliability. PV's geographic flexibility to be located close to load (and in congested load pockets) allows the use of PV as a mechanism to strengthen existing distribution systems that are stressed, and installations in certain locations may offset or delay necessary investments in the distribution system.[158] The impacts of different deployments on rate impacts was shown in Section 7.6, and the results showed that downstate deployment downstate provides a reduced rate impact compared to upstate deployment.

Though intermittent in nature and featuring relatively low capacity factors, PV production is highly coincident with summer peak loads and can help address reliability during peak periods. Localized reliability impacts in terms of supporting existing network conditions and/or affecting future grid planning and operating resources may be enabled by particular, locally targeted PV deployments, but these impacts are uncertain without further study and research.

Increased use of PV statewide is expected to reduce electricity delivery disruption risk. Quantification of this impact is beyond the scope of this study. A more urban deployment scenario, such as the Alt-A Deployment Scenario, may be more effective at meeting reliability objectives. Any PV policy adopted should take care to minimize negative grid planning and operating reserve impacts, and minimize distribution system negative reliability impacts (e.g. avoiding degradation of system loss of load probability).

11.2.4 Economic Development Objectives

Economic development objectives in terms of greater in-state economic activity and employment are also important to consider when evaluating policies. Chapter 6 provided a detailed discussion of the impacts of the base case and different sensitivities in terms of various economic metrics. Table 89 below summarizes economic development impacts of the base policy. Overall, the Base PV Scenario shows a net negative impact on job and GSP growth. Though net growth is positive through the first 10 years (largely due to the construction related impacts from PV installations), these results reverse over the next ten year period and continue to show deterioration through the end of the study period. These results are discussed in greater detail in Chapter 6.

Table 89. Economic Development Objectives, Base PV Scenario

Criteria	Metric (units)	Study Period (2013-2049)
ECONOMIC DEVELOPMENT OBJECTIVES		
Net In-State Employment Impact	Avg. Annual Job-Years	(750)
Net GSP Impact	(NPV M 2011$)	(1,600)

158 The converse can also be true, to the extent that MW-scale installations exceed a distribution feeder or circuit's capacity and require additional investment.

It is important to note that the results only reflect the impacts related to the various inputs (e.g., increased PV investment, net incentive required, price suppression, etc.) discussed in Chapter 6. There may be ancillary benefits, such as supporting the clean technology cluster and creating a stable investment climate for continued investment by these firms in New York. While the Chapter 6 macroeconomic analysis included a modest assumption of the role of New York manufacturers in capturing some of the policy's equipment investment (5%), a policy that created a 13 year interval to deploy PV statewide may create an opportunity to enhance NY's existing manufacturing base. If successful, then NY would see greater job and GSP impacts. An analysis of such possibilities is beyond the scope of this study, and is discussed further under areas for further research at the end of this chapter.

A sizable, long-term and stable PV policy will meet additional objectives in this category. For example, it can create a stable business planning environment conducive to attracting additional investment in the PV supply chain, and enhance the long-term business commitments to New York's PV market, and stimulate increased business investment. As discussed in Chapters 9 and 10, different policy mechanisms are expected to be more effective than others at creating these conditions. Experience has shown that quantity obligations without long-term revenue-stability mechanisms are subject to market volatility that works counter to such stability. On the other hand, standard offers (either up-front or performance-based) if available for a long term under predictable conditions have proven to create a stable business planning environment able to both grow the supply chain and (as observed in Germany) reduce the cost of PV installations. Procurement-based options (auctions, central procurement) also create stable environments for investment, but because both the level of revenue or incentive is not known in advance, and access to incentives is not assured, these policy mechanisms are somewhat less effective at creating a stable environment for business investment.

11.2.5 Energy Costs Objectives

As discussed Chapter 5, PV has the potential to provide a number of energy cost-related benefits:

- price suppression in wholesale energy and capacity markets as relatively high marginal cost fossil fuel generating units are displaced by PV generation
- market revenues from wholesale energy and capacity markets
- retail generation cost savings; and
- other benefits described in Table 32.

Countering these benefits are the actual costs of the policies in terms of required subsidies (where applicable). Table 90 shows relevant summary metrics related to energy costs.

The data show that the Base PV Scenario policy generates over 3 billion in wholesale price suppression benefits over the entire study period. Due to the sudden decrease in price suppression impacts in 2030, most of these benefits are concentrated in the first 20 years.

In terms of net ratepayer impact, Table 90 shows that the Base PV Scenario results in approximately 3 billion in net ratepayer impact over the entire study period with most of that rate impact occurring in years 11 through 20. Rate impacts are relatively small towards the end of the study period as earlier installed, more expensive solar installations are retired and avoided costs continue to rise (while solar costs fall). Finally, the table shows rate impact as a percentage of total average retail rates. Over the entire period, this rate impact is expected to lead to a 1% increase in rates above the reference case over the entire study period.

Table 90. Energy Costs Objectives, Base Policy Case, And Quantitative Metrics

Criteria	Metric (units)	Study Period (2013-2049)
Wholesale Price Suppression	(NPV M 2011$)	(3,300)
Net Ratepayer Impact	(NPV M 2011$)	3,400
	% of total bill	1%
Net Cost / Benefit	(NPV M 2011$)	2,200
MW-scale 2025 Installed Cost[159]	(M$ / MW)	2.5

11.2.6 Technology Policy Objectives

Ideally, the goal of a PV policy is to create a self-sustaining market, achieving market transformation. As discussed in Section 3.8.1, under the Base PV Cost future, small C&I installations approach parity with their value in avoided retail rates by 2025 in New York City, where electricity prices exceed all other regions in the state. In the Low PV Cost future scenario, such retail rate parity is reached for small C&I installations as early as 2017. For other installation types, sizes and location, achieving rate parity may occur later, after the analysis period. Energy prices will continue to rise beyond 2025, as projected in this study. For systems installed prior to 2025, which have not reached retail rate parity prior to 2025, their LCOE may fall below retail prices during their lives (reducing rate impacts). When future LCOEs fall below retail prices, the conditions for potential market transformation become apparent, where direct

159 By 2025 the cost of PV is expected to significantly decline, where the Base Case installed cost will range from $2.50 per W for MW-scale systems to $3.10 per W for the residential-scale system, in nominal dollars. For the Low Cost Case, the range is $1.40 per W to $2.00 per W and for the High Cost Case the range is $2.90 per W to $4.30 per W. It should be noted that this cost cannot be directly compared to the cost per installed MW for other technologies given that PV has a low relative capacity factor.

incentives may no longer be required (although some of the co-policies described in this study may still be required to address other barriers to adoption, similar to experience in the realm of energy efficiency).

Other aspects of technology policy objectives can be met with similar efficacy by PV policy mechanisms explored in this study, including assisting emerging technologies in becoming commercial technologies, and fostering technology innovation and development.

11.2.7 Societal Objectives

Additional objectives that may be considered by New York's policymakers in considering whether to adopt a PV policy include the following:

- **Ensuring geographic equity.** One objective may be to align benefits with those who bear the costs, an objective underlying adoption of the regional competitive bidding program discussed in Chapter 2. The ability for a policy to achieve a desired geographic distributional equity objective is determined by the deployment of installations, which in turn is driven by policy design details. As shown in the analysis throughout this study of the Base, Alt-A and Alt-B deployment scenarios introduced in Chapter 3**,** some distributions may be better at achieving an equitable distribution, but other (more urban/downstate oriented) distributions like Alt-A may be lower cost. This outcome highlights some of the tradeoffs inherent in identifying a preferred PV policy approach
- **Maximize benefits to environmental justice communities**. Location of PV in urban areas will tend to localize environmental benefits, particularly in the presence of congestion which requires the operation of local fossil fuel generators. The degree of urban concentration of installations is driven by design details, with the example of the Alt-A deployment providing a greater degree of benefits in this category than the Base or Alt-B deployments

11.3. Comparative Evaluation of Policy Mechanisms

The following Table shows the energy costs of the alternative policies. Other quantitative metrics related to environmental and economic development objectives were not calculated for these alternative policies.

Table 91. Energy Costs of Alternative Policy Mechanisms

Policy ➔		QO w/ Price Floor	EDC LT Contract Auction
Criteria	**Metric (units)**	**2013-2049**	**2013-2049**
Net Ratepayer Impact	(NPV M 2011$)	4,500	3,500
	% of total rates	1.2%	1.0%
Policy ➔		**Hybrid: Rebate/Central Proc.**	**Hybrid: Std. Offer PBI/LT Contract Auction**
Criteria	**Metric (units)**	**2013-2049**	**2013-2049**
Net Ratepayer Impact	(NPV M 2011$)	3,000	3,300
	% of total rates	0.8%	0.9%

11.4. Sensitivity Analyses

Similar to the analysis structure of Chapter 5, this section compares summary metrics for the base policy case relative to the different sensitivity cases. Only summary metrics that are common to the sensitivity cases and the base policy are shown.

11.4.1 Base Cost Case vs. High and Low PV Cost Futures

The Table below shows that summary metrics related to economic development impacts and energy costs are highly sensitive to the assumed level of federal incentives and the PV cost trajectory. Indeed, under low PV cost conditions, employment and GSP growth are both positive and the PV policy shows net benefits (rather than a net cost). By contrast, the high PV cost shows more sharply negative economic and cost impacts. Wholesale price suppression impacts did not change since PV facility sponsors are assumed to be price takers—that is, the price of PV does not impact wholesale markets (i.e., it is not used to determine wholesale market bids and thus wholesale market prices).

Table 92. Economic Development Impacts and Energy Costs, Base PV Scenario vs. High and Low PV Cost

		Base Cost	High Cost Future	Low Cost Future
Criteria	**Metric (units)**	**2013-2049**	**2013-2049**	**2013-2049**
ECONOMIC DEVELOPMENT OBJECTIVES				
Net In-State Employment Impact	Avg. Annual Job-Years	(750)	(2,500)	690
Net GSP Impact	(NPV M 2011$)	(2,900)	(10,000)	2,700
ENERGY COST OBJECTIVES				
Wholesale Price Suppression	(NPV M 2011$)	(3,300)	(3,300)	(3,300)
Net Ratepayer Impact	(NPV M 2011$)	3,400	8,700	340
	% of total rates,	1%	2%	0.1%
Net Cost / Benefit (positive = cost) (negative = benefit)	(NPV M 2011$)	2,200	7,600	(2,100)

11.4.2 Base PV Policy vs. Alt-A and Alt-B Deployment

Comparison of summary environmental metrics for the different geographic/project size category deployments shows the impacts of the different generating mix in the different parts of the state. The following Table shows that though fossil fuel consumption and avoided GHG impacts are similar across the three deployments, there are notable differences in SO_2 and mercury emissions. These differences reflect the specific emission characteristics of the existing plants that are displaced by the solar deployment for each deployment case.

Table 93. Environmental Impacts and Energy Costs, Base Policy vs. Alt-A and Alt-B Deployment

		Base Deployment	Alt-A Deployment	Alt-B Deployment
Criteria	**Metric (units)**	**2013-2049**	**2013-2049**	**2013-2049**
ENVIRONMENTAL OBJECTIVES				
CO_2 Reduction	M Tons of CO_2	(47,000,000)	(43,000,000)	(48,000,000)
CO_2 Reduction Benefit @ $15/ton	(NPV M 2011$)	(460)	(440)	(470)
CO_2 Reduction Benefit @ $107/ton	(NPV M 2011$)	(3,200)	(3,100)	(3,300)
Criteria Pollution Reduction	Tons of SO_2	(67,000)	(42,000)	(77,000)
	Tons of NO_x	(33,000)	(29,000)	(33,000)
	Pounds of Mercury	(120)	(66)	(140)
Criteria Pollution Reduction Benefits	(NPV M 2011$)	(33,000)	(29,000)	(33,000)
Reduction in Fossil Fuel Consumption	TBtu	(1,100)	(1,100)	(1,000)
Minimize Land Use	Greenfield Acres	3,000	2,600	6,000
ENERGY COSTS OBJECTIVES				
Wholesale Price Suppression	(NPV M 2011$)	(3,300)	(4,000)	(1,800)
Net Ratepayer Impact	(NPV M 2011$)	3,400	2,400	5,000
	% of total rates	1%	0.7%	1.4%
Net Cost Impact	(NPV M 2011$)	2,200	1,200	3,700

11.4.3 Base Case vs. High (Natural Gas) Price

The following Table shows the summary metrics for the High Natural Gas sensitivity case. In terms of environmental metrics, high natural gas prices lead to lower emissions impacts (of the criteria pollutants) of the PV deployment. Higher energy prices provides additional revenues for all plants, which permits dirtier coal plants to install retrofits, thus delaying retirement decisions. In sum, higher natural gas prices results in a cleaner existing generation mix and thus cleaner units that will be displaced by additional solar. Though this mix is cleaner, it still is heavily fossil based, thus producing similar reductions in fossil fuel and GHG for both the base policy and high natural gas case.

		Base Cost	High (Natural Gas) Price
Criteria	**Metric (units)**	**2013-2049**	**2013-2049**
ENVIRONMENTAL OBJECTIVES			
CO_2 Reduction	M Tons of CO_2	(47,000,000)	(45,000,000)
CO_2 Reduction Benefit @ $15/ton	(NPV M 2011$)	(460)	(360)
CO_2 Reduction Benefit @ $107/ton	(NPV M 2011$)	(3,200)	(2,500)
Criteria Pollution Reduction	Tons of SO_2	(67,000)	(42,000)
	Tons of NO_x	(33,000)	(21,000)
	Pounds of Mercury	(120)	(74)
Criteria Pollution Reduction Benefits	(NPV M 2011$)	(130)	(22)
Reduction in Fossil Fuel Consumption	TBtu	(1,100)	(1,000)
ECONOMIC DEVELOPMENT OBJECTIVES			
Net In-State Employment Impact	Avg. Annual Job-Years	(750)	(500)
Net GSP Impact	(NPV M 2011$)	(2,900)	(1,300)
ENERGY COSTS OBJECTIVES			
Wholesale Price Suppression	(NPV M 2011$)	(3,300)	(3,700)
Net Ratepayer Impact	(NPV M 2011$)	3,400	2,400
	% of total rates,	1%	0.6%
Net Cost Impact	(NPV M 2011$)	2,200	1,100

11.4.4 Base Scenario vs. Indian Point

As discussed in Chapter 5, the presence of Indian Point has relatively small impacts compared to the base case that does not assumed continued operation of the generating facility.

11.5. Key Findings

11.5.1 New York in the Global PV Market

- The global PV market has seen dramatic recent declines in PV panel prices
- These declines have benefited New York with installed costs dropping significantly in the past three years
- The existing global supply chain could adequately meet the needs of New York's market as it grows towards the 5,000 MW target

11.5.2 NYS Renewable Energy Policy Context

- New York has aggressive renewable energy goals and robust policies that support those goals
- Current New York policies support a range of renewable technologies including several high-cost early-stage generation sources, like PV, that have the potential to reach significant market penetration as costs decline
- New York has taken a holistic approach to development of a robust renewable energy market, including PV, through workforce development, as well as technology and business development initiatives
- Existing PV programs in New York have stimulated a stable and growing market, but this market is small in relation to other East Coast markets

11.5.3 PV Cost Projections

- The installed cost of PV in NY by 2025 is projected to range from $2 to $4 per Watt. The $2 per Watt projection represents a low-cost future based on the DOE SunShot goal. The $4 per Watt projection represents a high-cost future based on an extrapolation of historical price reduction trends. The most likely scenario is assumed to be a $3 per Watt projection based on a DOE review of PV experts.
- PV is not expected to achieve wholesale parity during the analysis period (2013 thru 2049) in any cost future.
- Retail parity may be achieved, and will occur sooner in NYC than in other regions of the state. This suggests a greater leverage of state PV incentive dollars in NYC. In a low-cost PV future there is parity in NYC by 2017.
- PV cost of energy is expected to be more expensive than large-scale onshore wind energy and will most likely be more expensive than off-shore wind in 2025.

- PV cost of energy may be competitive with small-scale wind energy and greenfield biomass technologies by 2025.
- Due to the differences between what is measured by cost of electricity and by the value of the energy produced, it is recommended that a full study of the costs and benefits of other renewable energy technologies be conducted to better inform renewable energy policy development.
- Federal incentives will play a critical role in the magnitude and predictability of future PV prices. In addition, the “SunShot” goal articulated by the U.S. DOE is an aggressive and meritorious goal that, if achieved, would substantially reduce PV cost and change the benefit-cost equation. It is recommended that New York should take particular interest in – and action on – these federal issues which are critical to future PV costs to consumers.

11.5.4 Benefit-Cost Analysis

- Future cost of PV and the federal incentive level were the primary drivers of total cost of reaching the Goal, while the location of installations and system sizes were secondary cost drivers
- Price suppression and avoided electricity production costs were the greatest drivers of benefits, while other factors, including reduction in air pollution, reduction in the use of fossil fuels, avoided distribution system upgrades, and avoided line losses showed smaller benefits
- Under the Base Case scenario, reaching the 5,000 MW target results in a net cost for New York of $2 billion
- Under the low cost scenario reaching the goal had a net benefit of $2 billion
- Under the high cost assumptions, the policy had a net cost of $8 billion
- Increased deployment of PV downstate had a higher benefit-cost ratio, lowering the overall costs of meeting the Goals by nearly $1 billion, as electricity costs are higher in the New York City region

11.5.5 Macroeconomic Impact

- Analysis conducted looked at the overall impacts to the New York job market, taking into consideration the jobs gained in the solar industry and elsewhere, as well as the potential job loss due to the costs imposed on the economy by the Goal.
- In terms of the total impact of the Base-Case PV deployment on the economy, there will be no economy-wide net-job gain, in fact, modeling showed a net job loss of 750 jobs per year because of the impact of increased electricity rates needed to pay for the PV program. Gross state product (GSP) would be reduced by $3 billion between 2013 and 2049, representing a small annual decrease in GSP of less than 0.1%.
- Deployment of PV to a level of 5,000 MW will create approximately 2,300 direct PV jobs associated with PV installation for the installation period (2013 – 2025) and an average of approximately 240 direct jobs per year associated with Operations and Maintenance (O&M) from 2025 – 2049.

- There will also be 600 jobs lost for the study period primarily as a result of the reduced need to expand and upgrade the distribution grid, a reduced need for conventional power plants, and reductions in in-state biomass fuel production.
- The sensitivity analysis demonstrates that a low PV cost future would lead to economic growth, including the creation of an average annual of 700 jobs and an additional $3 billion in GSP, while a high cost future would lead to a reduction in GSP of $9 billion and a net-job loss on the order of 2,500 annual average jobs.
- Subsidies at the scale required to achieve 5000 MW of PV by 2025 would most likely have a small net-negative impact on the economy; however, continued support for PV is warranted given the promise of a low cost PV future.

11.5.6 Retail Rate Impacts

- The net impact of the PV deployment on electricity bills takes into account the above-market costs of PV, the costs of net metering, and the savings generated by the suppression of wholesale electricity prices.
- The net impact of these factors on retail electricity rates is $3 billion over the study period, or approximately 0.9% of total electricity bills.
- Analyses of low and high PV cost scenarios were also conducted. The impact of the low PV cost scenario is approximately $300 million in additional ratepayer impacts or 0.1% of total bills, whereas the impact under the high cost scenario would be $9 billion or 2.4% of total bills.
- An analysis was also conducted to determine the effect of higher natural gas prices on PV impacts. Higher natural gas prices would reduce the above market cost of PV and lower the retail rate impact to 0.6% of total electricity bills instead of 0.9%.
- Since retail rates are higher in downstate areas such as New York City and lower in upstate New York, PV is closest to grid parity downstate. Concentrating smaller-scale PV installations downstate would result in lower overall retail rate impacts (0.7% of total bills) whereas installing a greater amount of larger-scale PV systems upstate would increase overall retail rate impacts (1.4% of bills).

11.5.7 Environmental Impacts

- Over the study period (2011 – 2049) PV will reduce fossil fuel by 1,000 trillion Btus (TBtus), which is equivalent to approximately 190,000 barrels of oil. This includes a 7% reduction in the use of natural gas, a 4% reduction in the use of coal, and a 40% reduction in the use of oil in the electricity sector in 2025.

- This reduction will lower CO_2 emissions by 47 million tons, equivalent to taking an average of approximately 250,000 cars off of the road for each year of the study period. The CO_2 emissions reductions are valued at between $450 million and $3.2 billion.

- A high valuation for CO_2 emission reductions has a significant enough benefit to make the Base Case a net-beneficial to New York.

- The amount of CO_2 reductions remains small compared to the total reductions that were identified for the power generation sector in the New York State Climate Action Plan Interim Report. In 2025, PV will reduce emissions by 1.7 million metric tons, or 5% of the emissions from the electric generation sector in that year.

- The reduction in fossil fuel use will lower NO_x by 67,000 tons, SO_2 by 33,000 tons and mercury by 120 pounds. The net present value of these combined reductions is $130 million over the study period. This valuation is based on health benefits only, and does not attempt to monetize ecosystem benefits (such as reductions in acidification of lakes, streams and forests, and eutrophication of estuaries and coastal waters).

- In 2025, PV will reduce total NO_x emissions by 4%, total SO_2 emissions by 17% and total mercury emissions by 6%.

- PV could also require land to site systems. It estimated that 5,000 MW of PV would require 23,000 acres of land if the entire amount was ground-mounted. However, there is a significant amount of roof space available, as well as areas such as brownfield sites, existing power plant sites, and parking lots, where PV could be deployed without using land that could have other productive uses. In total, it is estimated that PV would require from 2,600 – 6,000 acres of green field space total, which is less than 0.02% of total state land area.

11.5.8 PV Policies

- A comprehensive approach to PV deployment will likely include cash incentives as well as low-cost or no-cost complementary regulations such as streamlined permitting, interconnection standards, and building construction mandates that can reduce the installed cost of PV and drive demand.

- There is a range of policy incentive mechanisms, such as upfront payments, standard offer performance-based incentives, and quantity obligations. Although each of these mechanisms has different characteristics, the salient differences between policy types can be reduced through policy design. Even so, there are fundamental differences in terms of overall policy cost, investor security, and implementation.

- Renewable Energy Credits (RECs) are a policy tool that can be combined with most policy mechanisms. RECs that are traded on spot markets and are not supported by long-term contracts or price floors, however, are challenging to finance and increase the investor risk, and therefore cost, of quantity obligations.

- The longer the term for a PV incentive, the lower the $/kWh payment needs to be. Longer-term payments therefore create the opportunity for PV to reach parity faster.

- Incentive rates can be set administratively or through competitive processes. Competitive processes are consistent with New York's competitive electricity market, although they may create barriers to entry for smaller and less sophisticated market participants. Competitive processes can be used for larger projects, whereas administratively determined incentives can be used to target smaller projects.

11.5.9 Modeling of Policy Mechanisms

- The difference among the three least expensive policy mechanisms is less than 17%, which is potentially smaller than the impact of specific design choices including targeting deployment to specific installation types and locations.

- An up-front payment incentive for smaller customers (and central procurement for larger customers) similar to the policy approach used in New York for the RPS is the least expensive mechanism analyzed as part of this Study.

- A quantity obligation with price floor (similar to the policies in MA and NJ) is projected to cost 50% more than the least cost policy mechanism.

- Many complementary policies could be implemented at low or no overall cost in parallel with the analyzed incentive polices, on either a local or state-wide basis, potentially reducing the cost of and removing barriers to reaching the targets, and should therefore be considered as New York refines its solar policies.

- Costs to compete for and potentially negotiate a contract could be prohibitive for smaller-scale generators.

- Choices of policy mechanism that reduce investor risk, and administrative and transaction costs will have lower peak and average direct and net impacts on ratepayers.

11.6. Future Research Needs

This Solar Study was conducted spanning a wide range of topics under a schedule prescribed by the Act. Throughout the analysis, a number of issues arose which were identified as future research topics meriting further study. Listed here are the issues identified for future research:

- As pointed out in Section 1.2.1, in attempting to isolate the impact of a single policy, this study analyzes only the impact of achieving a 5,000 MW goal by 2025. In other words, no PV systems were modeled as installed after reaching 2025, no PV systems were modeled as replaced at the end of their assumed economic life, and no PV systems were assumed to continue producing electricity (albeit at a reduced level) after the end of their economic life. These assumptions were necessary to bound this study.

  Incorporating these issues presents a number of analytical challenges. There is considerable uncertainty regarding predicting market dynamics more than 15 years into the future. In addition, further study is necessary to determine the degree to which new PV installations beyond 2025 should be attributed to the policy being studied. Among other challenges would be the development of additional novel reference cases correlating to different cost and Federal incentive futures. Consequences of this approach include:

  - Under-calculation of benefits related to potential continued production following the economic life[160];
  - Creation of a precipitous drop in PV system installations, and thereby impacting many key metrics analyzed in this study, such as direct solar jobs and investment at a far lower cost (due to dropping PV costs). As can be seen from the analysis results, by 2025, PV is projected to achieve parity with retail rates by 2025 (2017 in the low PV cost future) in New York City, shortly thereafter in Long Island, and later for other regions. If market transformation creates an environment where these systems are retrofitted by the marketplace, the sharp drop off of PV-related jobs may or may not appear, and the approach may under-project job creation related to continued installations of new systems in those locations where PV systems are approaching or reaching rate parity; and
  - Exclude consideration of the likely presence of retrofit/rehabilitation and O&M jobs beyond the 25 year economic system life.

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160 This approach may artificially truncate the economic value of PV electric output from the installed base. In practice, while PV panels do wear out slowly over time, much of the installed base will continue producing at a reduced level well beyond 25 years. The cost of panel replacement at the end of the useful life could extend a system's life another 25 years for a small fraction of the cost of the initial investment. When examined against the expected cost of energy in the same timeframe, private investment to maintain production is likely to occur for many PV systems.

Further research is merited to develop a scenario to examine the implications of market transformation on potential continued investment in new systems beyond the 5000 MW targets and attribution of such impacts to the proposed policy. Such study should additionally forecast and consider continued operation of a realistic portion of the PV fleet at a degraded level after the 25 years of operation, as well as the economics of PV system rehabilitation on continued investment (including the possibility that PV systems are retrofitted by the owners with no further incentive required) and their commensurate production, and costs and benefits.

- The report did not directly address the question of how and where PV generated electricity could provide the highest intrinsic value for the State. Exploring the question of intrinsic physical value of injecting PV electricity on the New York power grid was beyond the scope of this study. Localized reliability impacts such as supporting existing network conditions and/or affecting future grid planning and operating resources may be enabled by particular, locally targeted PV deployments, but these impacts are uncertain without further study and research. This value is location-dependent, and should inform how and where to most effectively and cost-effectively foster the deployment of 5,000 MW of PV in New York. MW-scale green field PV installations may have a low LCOE due to scale economies, but also may provide lower value. Additional information on these potential effects would be a pre-requisite before New York could consider designing policies to optimize the capturing of these values without eroding other benefits of geographic or installation size diversity.
- Chapter 3 concluded with a projection of future PV LCOE compared to the LCOE of other renewable energy technologies. As pointed out in that chapter, a comparison between renewable energy technologies based on LCOE provides a useful but incomplete and potentially misleading metric for comparing the merits of renewable energy technologies. While LCOE is an effective tool to compare generating technologies which may differ with respect to up-front and ongoing costs, it does not account for differences in the value of renewable energy production stemming from factors such as differential production profiles, contributions to meeting system peak demands, avoidance of delivery losses, system integration costs, or avoidance or deferral of distribution facility investments. PV ranks better than some of the other renewable energy technologies on many of these factors. Due to the differences between what is measured by LCOE and by market value of production, a full study of the costs and benefits of all renewable energy technologies would be required in order to facilitate the most meaningful comparisons and draw the deepest and most durable conclusions about the relative merits of PV compared to other renewable technologies.
- The IPM model does not have the ability to address dynamic operating reserve requirements and how these might change under the PV targets established in the Act. Separate modeling and research is merited to quantify this impact in order to ascertain whether increased operating reserves might add materially to the cost of meeting the Act's targets.

- While experts generally accept the presence of wholesale energy and capacity price suppression that is expected to result from PV deployment, determining the level and duration of price suppression is a highly complex issue subject to many intricacies of the electricity system and markets. Some of these market dynamics are captured in the algorithms of the IPM model, which seeks to optimize system costs in the context of long-term supply, fuel prices, and demand, but others may not be explicitly accounted for. Additional research is needed to compare generalized model outputs to expected results of actual market transactions and regulatory functions to demonstrate the relative precision of the IPM model to assess price suppression.
- The administrative and transaction costs associated with the four selected policy mechanisms were not subjected to detailed analysis, in part because these factors would depend on design and implementation details that were beyond the scope of this study. Further study of design details and associated transaction and administrative costs may provide additional information necessary to discern a preference among the highlighted policy mechanisms. In addition, any such study should explore approaches specifically aimed to minimize transaction and administrative costs for each policy.
- Further research into the distribution system benefits is warranted, given the uncertainty in correlating the assumed dollar value of avoided distribution cost to PV deployment (the current assumption is based on analysis of energy efficiency deployment benefits).
- The State of New York has invested heavily in energy storage research. While the linkages between PV and storage are beyond the scope of this report, energy storage may play a synergistic role in the large-scale deployment of PV in the state, to help integrate this generally predictable but variable and non-dispatchable resource. For this reason, the ramifications of that research are an important context for this report. Further research may be merited to explore the potential linkages between storage and PV deployment, and the resultant potential macroeconomic benefits to the state.
- The valuation of air pollution benefits is based on health benefits only, and does not attempt to monetize ecosystem benefits (such as reductions in acidification of lakes, streams and forests, and eutrophication of estuaries and coastal waters). Further study in this area is warranted to better assist in the assessment of the full net cost benefit of PV.

APPENDIX 1 – PV MARKET, TECHNOLOGY AND PERFORMANCE TRENDS

A1.1. Cells and Modules

PV cell and module technology efficiencies have improved dramatically over the past decade with significant gains occurring for both laboratory and production cells. Figure 58 below shows the historical progression of laboratory solar cell record efficiencies for a range of technologies over the past three decades.

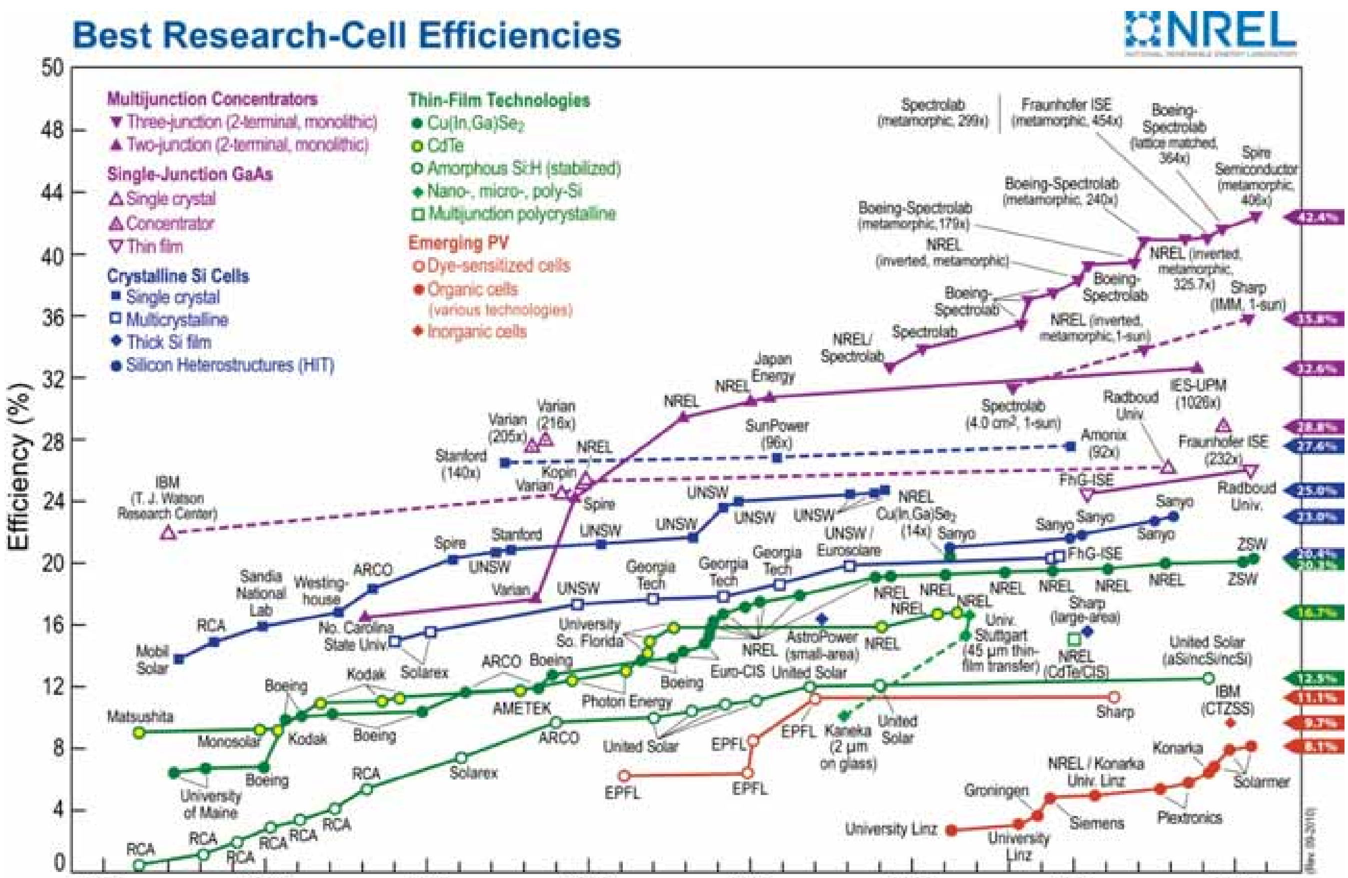

Figure 58. Research PV Cell Efficiency Records 1975-2011[161]

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161 Produced by the US DOE's National Renewable Energy Laboratory.

PV technologies are broadly categorized into three types, monocrystalline, multicrystalline and thin-film. Each of these technologies have different performance factors, efficiencies, costs and warranties. The following sections briefly discuss current market trends for these PV module types.[162]

Monocrystalline

Monocrystalline solar modules are the highest efficiency PV technologies currently available on the market. Solar cells in Monocrystalline panels are characterized by a single, uniform silicon crystal per solar cell. While this technology is typically more expensive to manufacture, it usually results in higher efficiency solar cells. Table 94 lists the top five highest efficiency monocrystalline solar modules currently on the market. Monocrystalline solar cells made up 31% of the global solar market in 2010 (Solar Buzz, 2010).

Table 94. Highest Efficiency Monocrystalline Production PV Panels (Photon, 2011d)

EFFICIENCY (%)	MANUFACTURER	MODEL	MODULE POWER (W)
20.42	SunPower Corp.	SPR-333NE-WHT-D	333
19.50	AU Optronics	SunForte PM318B00*	318
19.03	Sanyo Electronics Co.	HIT-N240SE10	240
18.30	Crown Renewable Energy	CR100*	100
17.35	Jiawei Solarchina Co.	JW-S95*	95
*Note: **These modules use SunPower solar cells.**			

Panel Degradation and Warranties

SunPower, a leading manufacturer of monocrystalline panels headquartered in the U.S., currently offers a 10-year limited warranty against manufacturing and workmanship defects. Additionally, SunPower provides a 25-year production warrantee that guarantees its panels will produce no less than 80% of their rated output over the 25-year panel life (SunPower, 2011). A twenty percent degradation over 25 years would result from an average 0.8% annual average degradation over the panels warranted life. Sanyo, another top-tier monocrystalline panel producer, provides a 76% power output guarantee for 25 years for its highest efficiency panels as well as a five-year workmanship and defects warrantee. As some of the leading

162 Note: The pricing analysis and modeling in other chapters in this report assume that market participants will choose the least-cost panel technology that is technically feasible for their project class.

global panel manufacturers, SunPower and Sanyo warrantees are among the most generous in the industry, however a number of top-tier manufacturers offer similar guarantees.

Multicrystalline

Mulitcrystalline silicon (mc-Si) solar cells are typically lower efficiency than monocrystalline silicon cells. Silicon wafers for mc-Si cells are grown in a less uniform fashion, with many separate crystals simultaneously growing during the cooling process (Markvart, 2000). The non-uniform nature of the silicon crystals results in less efficient solar cells. While this lower efficiency may be a drawback of mc-Si cells, they do not typically have the price premium associated with monocrystalline solar cells. Table 95 lists the top five highest efficiency multicrystalline solar modules currently on the market. Multicrystalline solar cells made up 55.5% of total global solar cell production in 2010 (Solar Buzz, 2010).

Table 95. Top Five Highest Efficiency Multicrystalline PV Manufacturers (Photon, 2011c)

EFFICIENCY (%)	MANUFACTURER	MODEL	MODULE POWER (W)
15.95	Istar Solar	IS4000IP	308
15.70	Door Sistem	DS72310(310)	310
15.63	Powrquant Photovoltaik	PQ-240-PS2	240
15.54	Canadian Solar	CS6P250P	250
15.54	Chinaland Solar Energy	CHN300-72P	300

Panel Degradation and Warranties

Multicrytalline solar panels typically have similar warranties to monocrystalline panels. Many leading manufacturers produce both multi- and mono-crystalline solar module lines and warranties for different cell types do not typically differ. For instance, Suntech Power manufactures mono- and multi-crytalline panels and offers the same 90% for 12 years/80% for 25 years production guarantee for both panel types.

Thin Film

Thin-film solar technologies include a range of different cell types, including Copper Indium Gallium Selenide (CIGS), Copper Indium Selenide (CIS), Cadmium Telluride (CdTe) and amorphous silicon (a-Si). Each of these technologies has their own unique design and performance characteristics; however, in general, thin-film solar modules and cells are lower efficiency than either crystalline silicon technologies. The lower efficiency of thin-film technologies, nevertheless, is balanced against lower production and materials costs for thin-film panels.[163] Due to these lower efficiencies, thin film solar products have been

[163] First Solar, a leading manufacturer of thin-film solar products, reported an average production cost of $0.75 per watt in Q2 2011 http://www.firstsolar.com/Downloads/pdf/FastFacts_PHX_NA.pdf

popular with utility-scale and large commercial solar sectors where installation space may be less constrained. Table 96 lists the top five highest efficiency thin-film solar modules currently on the market. Thin-film solar cells made up 13.5% of the global market in 2010 (Solar Buzz, 2010).

Table 96. Highest Efficiency Thin-Film Production PV Panels (Photon, 2011)

EFFICIENCY (%)	MANUFACTURER	MODULE NAME	POWER (W)
12.67	Q-Cells	Q Smart UF 95	95
12.60	Avancis	Powermax 135	135
12.23	Yokhon Energia	YEC200_160	160
12.21	Solar Frontier	SF150-L	150
11.81	First Solar	FS-385	85

Panel Degradation and Warranties

Q-Cell, the German manufacturer of the highest efficiency thin-film solar module on the market, currently provides a ten-year product warranty against workmanship and manufacturing defects. Additionally, Q-Cell's Smart line includes a, 80% production guarantee for the first 25 years of the panel life (Photon, 2011f). First Solar, the global thin-film leader in annual sales provides a similar 80% production guarantee for 25 years on its panels.

Cells and Modules Market Characterization

As the global PV market has matured in recent years, cell and module manufacturing has become a multi-billion dollar industry with international, publicly-traded firms now play a significant role in the market.[164] As an indication of diversity within the industry the California Solar Initiative maintains a list of solar modules that meet the criteria for its solar rebate program. This database currently lists more than 300 PV brands that have their products approved for sale in California programs (California Solar Initiative, 2011). Similarly, a survey of global manufacturers recently found more than 892 vendors manufacturing more than 27,000 separate module lines in mid-2011 (Haase, Podewils, & Hirsch, 2011). While there has been considerable growth in the number of manufacturers offering solar panels globally, some analysts are predicting near-term consolidation of the industry as rapidly dropping panel prices force non-competitive manufacturers out of business.[165]

Global solar panel prices have decreased significantly over the past decade as global manufacturing capacity has grown and manufacturing techniques have improved. During the early part of the last decade average prices from PV panels ranged from between four and five dollars a watt. Figure 59 shows global

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164 As of October 15, 2011, SunPower had a market cap of $553 million, First Solar had a market cap of $4.8 billion and SunTech $392 million.

165 The recent high-profile bankruptcies of Solyndra of California and Evergreen Solar of Mass. were, in part, attributed to global market price declines.

solar module prices in dollars per watt from 1998 to 2010. The recent entrance of low-cost manufacturers from Asia, along with lowered demand growth in several major European markets has led to a global PV panel supply glut. Panel prices have been rapidly declining over the course of 2011 (SolarBuzz, 2011). Industry media have also reported crystalline solar module prices at or near $1.00 per watt, a significant industry milestone (Wesoff, 2011c). Additionally, the SolarBuzz index reports a 27% decline in module prices between October 2010 and October 2011. Similarly, Photon has reported an 18% module price decline over calendar year 2011 (Siemer, 2011a). It is unknown whether this dramatic, recent decline in global module prices will lead to long-term stable prices at or below current levels, or whether increasing demand will lead to higher prices in the near future. Given the policy-driven nature of the global PV market, module price trends will likely continue to be significantly influenced by incentive policies in major markets.

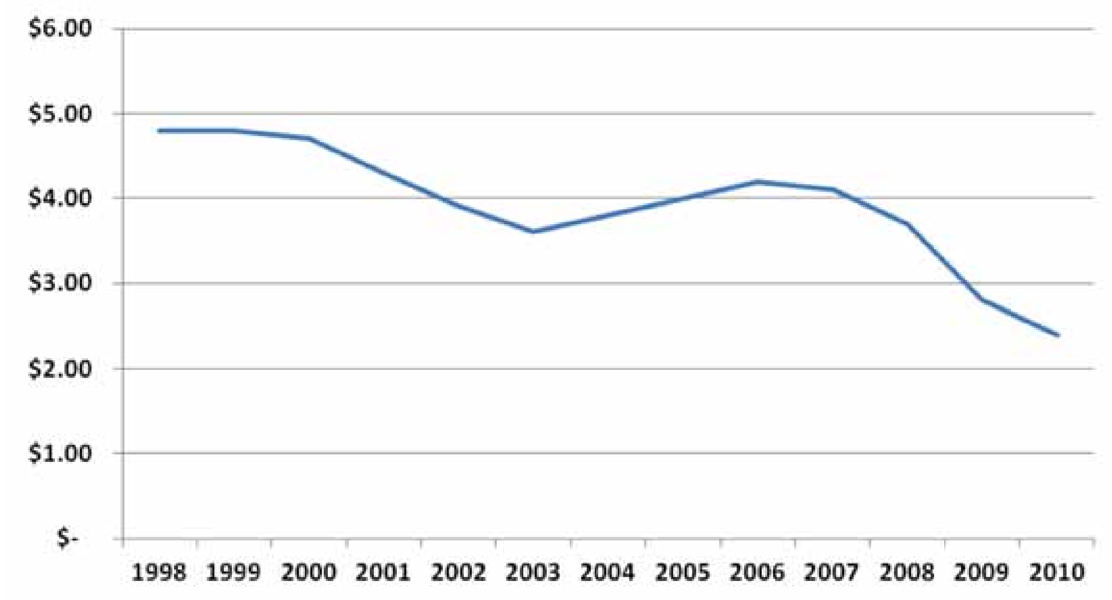

Figure 59. Global PV Module Price Index, 1998-2010
(Barbose, Darghouth, Wiser, & Seel, 2011)

The significant downward price pressure from Chinese PV panel manufacturers has spurred industry growth, but has been detrimental to a number of U.S.-based manufacturers. In October of 2011, a consortium of six U.S.-based PV manufacturers initiated World Trade Organization proceedings against China (Wesoff, 2011a). The consortium's complaint argues that Chinese solar panel manufacturing subsidies have forced global panel prices below manufacturing costs, effectively forcing U.S.-based manufacturers to cut staff or close manufacturing facilities. The outcome of this anti-dumping filing may take several years to resolve. A recent study by the Solar Energy Industry Association highlights the complexity of the global solar supply chain, reporting that, while the majority of U.S. installations include panels from overseas manufacturers, the U.S. has a positive global trade balance in solar goods, as many foreign cell and panel manufacturers rely on polysilicon sourced from U.S. foundries (GTM Research, 2011b).

Despite this recent proliferation of solar panel manufacturers, the New York solar module market is currently dominated by a few panel brands. Table 97 lists the top eight PV panel manufacturers by current capacity in the NYSERDA upfront incentive program database.

Table 97. Top 8 Panel Manufacturers in the NYSERDA Upfront Incentive Program Database.

MANUFACTURER	INSTALLED MW	PERCENT OF TOTAL NYSERDA CAPACITY
SunPower	10.7	29.9
Sharp	6.5	18.1
Kyocera Solar	3.2	8.9
Suntech Power	3.1	8.7
Sanyo Electric	1.9	5.3
Evergreen Solar*	1.8	5.1
Schuco USA	1.0	2.9
Schott Solar	1.0	2.7
*Note: This manufacturing firm has declared bankruptcy		

Global Cell and Module Supply in Context of New York State Policymaking

Analysts estimate that the global production of solar cells was 18.23 GW in 2010 with a global manufacturing capacity of more than 20.5 GW (Solar Buzz, 2010). The expected maximum annual solar capacity additions that would be required to support 5000 MW being installed by 2025 is 568 MW in 2025. This theoretical 2025 capacity addition represents only 2.7% of the global solar cell market in 2010. Given the likely evolution of solar technologies over the next decade and the anticipated expansion of manufacturing capacity to meet global demand, the New York market would be unlikely to significantly influence the global solar cell market trying to reach 5000 MW in installations.

A1.2. Inverters

Inverters were once considered the least reliable and most failure-prone component of PV systems. As the market has matured, manufacturing quality has improved and inverter manufacturers are increasingly providing extended warranties on their products. Many of the top-tier inverter manufacturers are now offering customers the option to purchase 20-year warranties on their products. (SMA, 2011b; Fronius, 2011)(Fronius, 2011). From the system owner’s perspective, these extended warranties effectively extend the life of the inverter to around the expected life of the PV system, meaning that system owners should not expect to make major capital investments for replacement parts during the majority of the system life.

As manufacturing reliability has improved over the past decade, inverter efficiency has also improved. Table 98 shows the average efficiency by year of inverters installed as part of the NYSERDA rebate programs. As the table shows, average inverter efficiency steadily improved during the middle part of the last decade, but has recently leveled off.

Table 98. Average Efficiency of Inverters in NYSERDA Program Database 2003-2011

YEAR	EFFICIENCY	ST. DEV	MAX	MIN
2003	92.0%	1.4%	93.0%	88.0%
2004	91.9%	1.6%	94.0%	88.0%
2005	93.0%	1.5%	96.0%	88.0%
2006	93.6%	1.6%	96.0%	88.0%
2007	94.3%	1.3%	97.5%	89.0%
2008	95.0%	1.0%	96.0%	88.0%
2009	95.2%	0.8%	96.0%	91.0%
2010	95.5%	0.6%	98.0%	91.0%
2011	95.4%	0.8%	98.0%	91.0%

Inverter Market Characterization

A recent survey of the global PV inverter market by Photon magazine found more than 50 suppliers currently active in the U.S. market. These firms range from globally recognized brands such as SMA and Fronius, to local and regional suppliers and startup companies. The same Photon survey estimated a global production capacity of at the end of 2010 at 29.8 GW and an anticipated 23.1 GW capacity expansion during 2011 (Siemer, 2011b). There is significant variability in estimates of both global inverter capacity as well as the annual inverter market. SMA, the leading global inverter manufacturer estimates that the world production at the close of 2010 was between 17 and 20 GW (SMA Solar Technology, 2011a). Greentech Media, another research firm that follows the global inverter markets, estimated the global market at 21 GW in 2010 (GTM Research, 2011a). These estimates do not provide associated capacity utilization estimates, however global production estimates are a reasonable lower bound for global manufacturing capacity.

Several large companies hold a significant market share of the global solar inverter market. These include European manufacturers such as SMA, Power-One and Fronius and American firms such as Massachusetts-based SatCon. Several of these manufacturers currently supply a major portion of the New York market. Table 99 shows the top inverter manufacturer brands for PV systems installed as part of the NYSERDA upfront incentive program.

Table 99. Top Eight Inverter Brands and Installed Capacity in the NYSERDA Upfront Incentive Program Database.

INVERTER BRAND	MW INSTALLED IN NYSERDA UPFRONT INCENTIVE PROGRAMS (MW)	SHARE OF TOTAL INSTALLED NYSERDA CAPACITY
SMA America	10.8	30.2%
SunPower	8.9	24.7%
SatCon Technology	4.4	12.1%
Fronius USA	4.3	11.8%
PV Powered	3.5	9.6%
Xantrex Technology	1.5	4.2%
Solectria Renewables	1.1	3.0%
Enphase Energy	0.7	2.1%

Global Inverter Supply in Context

Chapter 4 of this report estimates annual incremental installations that would be required to meet a state 5 gigawatt (GW) by 2025 goal. From this analysis, the anticipated maximum annual inverter demand that would be needed to support installation of 5000 MW in New York is 568 MW in 2025. This represents a little over 1% of expected global inverter manufacturing capacity in 2011. Given the likely global growth of the PV market over the next decades, annual demand for inverters in New York under an aggressive 5000 MW by 2025 scenario would be unlikely to significantly impact global inverter markets.

A recent industry survey of U.S. based solar component manufacturers by Photon Magazine identified two manufacturers producing inverters in New York.[166] While these firms had limited production during 2010, as they were new ventures, as of March 2011, these companies report a combined expected 2011 production capacity of more than 240 MW annually (Matz, 2011). Of note, the same Photon analysis found more than 2.5 GW of expected 2011 production capacity in the Canadian province of Ontario. Domestic content requirements associated with the Ontario feed-in tariff have driven rapid expansion of Ontario's PV component production capacity. The analysis estimated that 0.7 GW of inverter manufacturing was online in Ontario 2010.[167]

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166 These were Direct Grid Technologies LLC of Edgewood, NY and Sepsa Electronica de Potencia SL of Ballston Spa, NY.

167 The Ontario feed-in tariff currently requires that PV system have 60 percent domestically sourced content. This can include any system component as well as labor and design costs. Ontario's generous PV rates have attracted a number of manufacturers into the Province. 2011 tariff rates in Ontario are roughly between 1.5 and 2 times the PV feed-in tariff rates found in Germany, with both countries having similar contract lengths.

Polysilicon Market Characterization

One of the primary components and cost drivers for crystalline PV panels is polysilicon, a manufactured commodity that has been used for decades in the microchip industry. In recent years, the global polysilicon supply market has gone from severe shortage to significant oversupply. Over the past three years, prices have dropped more than 93% from their record highs (Roca & Sills, 2011). As demand for PVs increased globally during the later part of the last decade, global silicon supplies shortages led to prices in excess of $475 per kg. This supply shortage led to significant capacity expansions by existing silicon manufactures and the entrance of new players into the market, particularly from China.

Given the long timelines necessary to build a silicon plant and the significant capital investments involved, a global glut in polysilicon supply has developed. Despite this oversupply, manufacturers continue to bring new capacity online, further over-supplying the market (Marting & Tracer, 2011). Today, spot prices for silicon have reached $33 per kg, and analysts are estimating that with new production capacity coming online in the near term, that silicon will continue to be near-cost for the foreseeable future with the potential for some suppliers to leave the industry (Roca & Sills, 2011). Given the current supply glut and future expectations of manufacturers exiting the industry, it is unlikely that global polysilicon supply would be a significant constraint on New York reaching a 5,000 MW target.

A1.3. Potential Disruptive Technologies and Market Developments

In 2009, the U.S. Department of Energy's (USDOE) Solar Energy Technologies Program commissioned a survey of leading solar technology experts to help better understand the U.S. solar market and gauge the industry's opinions on market trends. Part of this survey project was an evaluation of the likelihood that disruptive advancements in solar technology could significantly change the marketplace by 2050 (Sentech, Inc., 2010). The survey asked experts to rate the likelihood that a number of transformative technology advancements would occur between 2010 and 2050. Table 100 lists advanced technology market penetration milestones experts were asked to evaluate and also provides the expert's aggregate expected likelihood that these milestones would be met in 2015, 2030 or 2050.[168]

[168] US DOE conducted this analysis in order to gauge the effectiveness of its programs and the likelihood of those programs would help drive solar market penetration towards these milestones. As such, the DOE study evaluated three scenarios: 1) a loss of DOE research funding, 2) DOE funding at existing (2009) levels, and 3) increased annual funding. This chart presents likelihoods from the mid-case funding scenario with business-as-usual USDOE funding.

Table 100. Results of 2009 DOE Market Transformation Expert Survey

POTENTIAL MARKET TRANSFORMING PV TECHNOLOGY ADVANCEMENTS			
Market Advancement	**Likelihood (%)**		
Silicon Modules	**2015**	**2030**	**2050**
1) Kerfless wafering at about 1 gram per watt achieving at least 20% of wafering industry's annual production	19	63	73
2) Upgraded metallurgical-grade (UMG) silicon (no Siemens or Fluidized Bed Reactor processing) provides greater than 20% of industry's annual cell manufacturing	16	47	57
3) Ultrathin (≤100 μ) wafer thickness achieved in greater than 20% of annual wiresaw wafering production	14	39	49
Thin Films	**2015**	**2030**	**2050**
1) Greater than 15% thin film module efficiency in unconcentrated, terrestrial commercial modules	18	59	72
2) Flexible modules make up more than 20% of annual market	6	22	31
3) Organic PV modules make up more than 20% of annual market	2	11	17
4) Copper indium gallium selenide (CIGS) modules make up more than 20% of annual market	15	30	35
Inverters and Systems	**2015**	**2030**	**2050**
1) Economical 30-year warrantee available on greater than 20% annual inverter market	27	81	82
2) Alternating-current PV modules (microinverters) achieve at least a 20% annual market share of residential rooftop installations	29	64	82
3) 20% of new inverter installations employ time-of-use pricing operation	54	88	90
4) 20% of grid tied systems incorporating energy storage functionality (i.e., battery or plug-in hybrid electric vehicle)	30	79	86
Installations	**2015**	**2030**	**2050**
1) Physical installation of building-integrated PV shingle by non-PV-trained roofer achieves greater than 20% of annual residential installations	38	78	86
2) Commercial roofing PV membrane makes up more than 20% of annual commercial rooftop installations	28	59	71
3) Highly automated ground installations (~1 MW/year/installer)	37	92	96
4) Concentrating PV (>100x concentration) achieves 20% of annual ground mount installations	18	39	54

Illustrating the rapidly shifting nature of the PV technology market, one of these expected market-transforming technologies is already widely available and is being actively deployed in U.S. markets. Microinverters currently make up 25% of all inverters installed in residential PV systems in California for 2011 (California Solar Initiative, 2011). The 2009 DOE expert survey only reported a 29% probably of microinverters reaching 20% market penetration by 2015. To date, there are limited numbers of microinverter manufacturers offering these products, however leading inverter manufacturers are entering the market with their own products meaning market share for this technology could rapidly expand in the near future (Wesoff, 2011b) .

APPENDIX 2 – PV POLICY FRAMEWORK AND ANALYSIS

A2.1. Introduction

This Appendix provides detail and additional analysis on policy design and selection considerations that relate primarily to Chapter 9, but which are relevant to the entire report. The following topics are discussed in this Appendix:

- **Complementary policies.** The section on complementary policies contains brief descriptions of a range of incentives and regulations that could be implemented in tandem with the core policy mechanisms in order to accelerate PV deployment and/or lower PV costs.
- **Core policy mechanism description.** This section provides a detailed overview of the designs of the core policy mechanisms, including a discussion of how the mechanism fit into the framework described in Section 9.3.3, the primary design variations of each mechanism, and a detailed description of each mechanism's strengths and limitations.
- **Best practices.** This section discusses policy design best practices synthesized over the course of this study. The best practices are described from the investor, ratepayer, and policymaker perspectives.
- **Cost control mechanisms.** This section provides an overview of the cost control mechanisms typically associated with each of the core policy mechanisms: standard offer PBIs, standard offer upfront payments, and quantity obligations.
- **Case studies.** This section presents case studies of PV policy in Germany, Spain and New Jersey. For each case study, details about the policy goals, structure, evolution, market impact to date, cost control mechanisms, and lessons learned are discussed.

A2.2. Complementary Policies

Streamlined Permitting

Permitting costs can account for a significant portion of the soft costs of a solar installation, especially at the residential level. In the U.S., requirements to obtain a permit for the construction of a solar project are determined by local authorities, and can vary significantly. SunRun, a leading financier of residential solar projects, estimates that learning and adhering to local permitting and inspection processes adds $0.50 per watt to a PV installation. (SunRun, 2011). A streamlined and consistent permitting process for solar installers can reduce these 'soft' costs, making solar projects more financially feasible. Germany has implemented a national permitting process, and now enjoys installed costs that are 40% lower than in the U.S. (SunRun, 2011). A study completed by AECOM in July 2011 determined that a streamlined permitting process in California would lead to a 13% increase in solar installations relative to market projections through 2020 based on current permitting practices, contributing $5.1 billion to the California economy, create 3,900 full time jobs, and securing an additional $270 million in tax revenues (AECOM, 2011). Best practices and additional information can be found in these resources:

- SunRun. (2011). *The Impact of Local Permitting on the Cost of Solar Power.* Retrieved from http://www.sunrunhome.com/uploads/media_items/solar-report-on-cost-of-solar-local-permitting.original.pdf
- AECOM. (2011). *Economic and Fiscal Impact Analysis of Residential Solar Permitting Reform.* Retrieved from http://www.sunrunhome.com/uploads/media_items/aecom-executive-summary.original.pdf

Solar Building Requirements

State and local governments have implemented policies requiring new buildings to meet either solar "readiness" requirements or to incorporate solar in new construction. In Massachusetts, the City of Boston requires all new construction affordable housing to meet solar readiness standards which allow for easy integration of solar technology in the future. State-level PV readyness requirements are not common, however, the American protectorate of Guam and British Columbia in Canada have building regulations that require private structures to meet readyness guidelines for solar hot water installations (McNab, 2011; Guam Energy Office, 2011). Additionally, Hawaii requires all new single family homes to include solar hot water installations (State of Hawaii, 2008). States have also implemented requirements that new public buildings (or buildings undergoing signficant renovations) integrate solar technologies. Oregon requires that major buidling projects dedicate not less than 1.5% of total project bugets towards "appropriate solar energy technology" (State of Oregon, 2007). Additionally, the State of California requires public buildings to install solar technologies on all buildings where it is considered cost effective (State of California, 2007). Best practices and additionaly information can be found in:

- Lisell, L., Tetreault, T., & Watson, A. (2009). *Solar Ready Buildings Planning guide.* Golden, CO: National Renewable Energy Laboratory. Retrieved from http://www.nrel.gov/docs/fy10osti/46078.pdf

Improved or Uniform Interconnection Standards

State utility regulators typically have oversight of distributed generation interconnection standards and are responsible for setting policies that allow PV to interconnect to the electricity grid. Poorly designed or implemented interconnection policies can be a deterrent to PV market development, with high interconnection costs, delays in administrative approvals, restrictive siting rules and system size caps potentially affecting market growth. Consistent and well-enforced state-wide policies can aid in overcoming some of these barriers. The Interstate Renewable Energy Council (IREC) publishes and regularly updates a best practices guide for interconnection policies (IREC, 2009a).

Best practices and additional information can be found at:

- IREC. (2009). *Model Interconnection Procedures: 2009 Edition.* Retrieved from http://irecusa.org/wp-content/uploads/2010/01/IREC-Interconnection-Procedures-2010final.pdf

Net Metering

Net metering is an electricity metering policy that allows owners of PV and other eligible distributed generation systems to export power to the grid during times when on-site power generation exceeds on-site power consumption and be compensated at retail electric rates for exported power. Under best-practice net-metering regulations, excess power exported to the grid on a billing period can be carried forward to future metering periods, allowing system owners to capture the full benefits of on-site power generation. Properly designed net-metering policies are critical to the development of a distributed PV market. The Interstate Renewable Energy Council (IREC) has published a best practices guide and model regulations for state policy markers (IREC, 2009b).

Best practices and additional information can be found at:

- IREC. (2009). *Net Metering Model Rules: 2009 Edition.* Retrieved from http://www.irecusa.org/NMmodel09

PV Access and PV Rights Laws

PV access laws consist of easements, covenants, or local ordinances that grant property owners the ability to secure access to sunlight. PV rights laws guarantee property owners the ability to install solar without running afoul of homeowner’s association restrictions or local land use restrictions that attempt to limit solar installations on private property. PV access laws are important because they allow private property owners to install PV on their property without unreasonable local restrictions. PV rights are important in order to protect property owners against their PV system being shaded by vegetation or neighboring buildings. Best practices and additional information can be found in these resources:

- Kettles, C. (2008). A Comprehensive Review of Solar Access Law in the United States. Retrieved from http://www.solarabcs.org/about/publications/reports/solar-access/pdfs/Solaraccess-full.pdf
- Stoel Rives. (2011). Lex Helius: The Law of Solar Energy. Retrieved from http://www.stoel.com/webfiles/lawofsolarenergy.pdf

Community PV/Virtual Net Metering

Community solar programs usually take the form of community members claiming proportional ownership rights in or purchasing “shares” of a larger PV system. Participants often either use the “virtual net metering credits” produced by the system or receive a utility bill credit in relation to the amount of the PV system in which they have an ownership stake. Community solar programs allow renters, certain condominium owners, municipalities or other individuals who could not otherwise participate in solar programs to “invest” in a solar project. Depending on how the program is structured community solar programs can be considered a security and be required to register with the SEC, especially if actual ownership with expected returns on investment is offered to participants. For this reason, in many current examples the local utility owns the project and sells the output as “shares” via a utility coordinated community solar program.

Several Northeast states have also implemented innovative net-metering rules to encourage community solar installations. For example, both Massachusetts and Rhode Island have net metering regulations that allow PV system owners to assign excess net metering credits to utility meters that are not on the PV system site. Know as *virtual net metering*[169] this distributed generation metering configuration can allow multiple project investors to receive the net metering benefits of a remote PV system.

Best practices and additional information can be found in these resources:

- IREC. (2010) Community Renewables: Model Program Rules. Retrieved from: http://irecusa.org/wp-content/uploads/2010/11/IREC-Community-Renewables-Report-11-16-10_FINAL.pdf
- NSEED. (2009) The Northwest Community Solar Guide, Bonneville Environmental Foundation. Retrieved from: www.nwseed.org/documents/NW Community Solar Guide.pdf
- NREL. (2010). A Guide to Community Solar: Utility, Private, and Non-profit Project Development, Retrieved from: http://solaramericacommunities.energy.gov/pdfs/A%20Guide%20to%20Community%20Solar.pdf

Group Purchasing

Group purchasing programs are volume discount purchasing mechanisms often employed either by a government entity or a local non-profit organization. These programs are sometimes called solar aggregation programs, collaborative procurement efforts, or “Solarize” campaigns. These efforts can reduce the cost of PV installations by purchasing system components or organizing systems installations in bulk. Group purchase programs reduce transaction costs by coordinating site visits, permitting and

[169] Virtual net metering applied broadly, or just to certain categories of hosts, is also referred to in various jurisdictions as aggregate, neighborhood, remote, municipal, or agricultural net metering.

installation. Furthermore, programs can educate and mobilize interest within a target community or organization. Best practices and additional information can be found in these resources:

- U.S. DOE. (2011). The Solarize Guidebook. Retrieved from: http://www.portlandonline.com/bps/index.cfm?&c=54114
- World Resource Institute. (2011). Best-Practice Guide to Collaborative Solar Purchasing. Retrieved from http://www.wri.org/publication/purchasing-power

Policies to Support Local Content

A number of solar incentive programs have been designed to promote the development of local supply-chain industries. These can range from domestic content requirements for participation in incentive programs to bonus incentives for the use of in-state manufactured goods. The Ontario feed-in tariff requires all qualifying PV systems to contain no less than 60% content manufactured in Ontario. This policy has led a number of solar inverter and panel manufacturers to build facilities in the province. Other state-level incentive programs allow content from any source, but provide bonus incentives for local content. The Massachusetts Commonwealth Solar II rebate program provides an added incentive for residential and small business PV systems that incorporate local content.

Targeted Support for Low-Income Programs

Recognizing that all ratepayers typically contribute to funding solar incentive programs, while the high-cost of PV may prevent low and moderate income property owners from installing solar, some states provide added incentives for low and moderate income homeowners to install solar. One notable example of this policy is the Massachusetts Commonwealth Solar II program that provides significant rebate additions to homeowners that meet certain income criteria. States may also develop solar incentive programs specifically targeted at low-income residents. During the past few years, Massachusetts has had a targeted grant program to support solar installations on affordable housing units.

State Tax Credits

ITCs have been used as an effective method to expand solar markets. These tax credits can be directly applied to the system owner’s tax liability, effectively offsetting a percentage of the total upfront project cost. Tax credits can be superior to a cash grant or rebate in certain respects, as they don’t face the same administrative and political challenges of appropriating limited financial resources. Still, they are only effective if the system owner has a tax appetite, which excludes public entities and non-profit organizations. Approximately 20 states currently offer tax credits ranging from 10% to 50% of the total project costs, usually with a maximum credit limit (DSIRE, 2011b). More information on state tax credits, including case studies, is available in the Database of State Incentives for Renewable Energy (DSIRE) Solar Policy Guide.

State Tax Exemptions

Along with tax credits, states can use tax exemptions for solar activities. A popular tax exemption is offering reduced or no sales tax around the purchase and installation of PV equipment. Approximately 20 states have enacted sales tax exemptions. Some states have also authorized local authorities to offer sales tax exemptions on municipal sales taxes (DSIRE, 2011b)

Governments have also used property tax exemptions to promote solar development. Solar facilities are at a disadvantage compared to more traditional power plants, as their high upfront capital costs can result in higher property taxes. Often, property tax exemptions are used not only as an incentive, but to prevent high taxes from hindering investment in solar (DSIRE, 2011b)

Industry Recruitment and Support

There is a variety of tools available to governments for promoting the local growth of clean energy industries at all parts of the value chain, from research and development to financing, manufacturing, installation and maintenance. Tax credits have been used widely for this purpose, and can be valued anywhere from 5 – 50% of construction costs or up to 100% of corporate taxes (DSIRE, 2011b). Other tools include grants, loans, property tax abatements, corporate tax abatements. Incentives can also be used on the customer side to promote the purchase of in-state manufactured solar equipment. These incentive programs can be an efficient way of driving economic development, creating new jobs, and capturing the financial and social benefits of a growing energy market. Best practices and additional information can be found in at: DSIRE Solar. (2011). DSIRE Solar Policy Guide: A Resource for State Policymakers.

State PV Loan Programs

A recent survey by DSIRE found that approximately 30 states have financing programs that could provide subsidized financing for PV projects (DSIRE, 2011b). Many of these programs are designed to support energy efficiency technologies, but may be applied to PV as well. State solar lending initiatives vary widely with some focusing on commercial and industrial installations and others providing financing to homeowners. These programs can be used to correct several problems in the private financing market by (i) stretching debt claims beyond what may be available in the marketplace, (ii) decreasing interest rates through interest-rate buy-downs or credit support mechanisms, (iii) creating more flexible underwriting standards based on expected project revenue, or (iv) decreasing lender fees. Many states have opted to partner with private-sector lenders to implement financing programs in order to take advantage of their expertise and loan servicing infrastructure.

PACE Financing

Property Assessed Clean Energy financing, or PACE, is a local government financing tool that allows municipal governments to lend funds to property owners and collect re-payments through property tax bills.

PACE programs may be attractive to property owners as they allow the financing re-payment obligations to transfer with the property. The added security of property-tax repayment may also allow PACE financing programs to attract lower-cost financing than traditional lending programs. PACE financing programs have been implemented in a number of municipalities; however, a 2010 decision by the Federal Housing Finance Administration (FHFA) has limited the expansion of PACE programs for residential property owners. Sonoma County in California operates one of the most successful PACE programs in the country and has decided to continue implementing its program despite pending litigation related to the FHFA regulations (Energy Independence, 2011).

On-bill Financing

On-bill financing is a financing tool that allows PV system owners repay a loan obligation through an existing utility bill. Similar to PACE financing, on-bill financing allows repayment obligations for energy financing to stay with a property. This may be an attractive option for some building owners installing PV as it allows them to stretch repayment over many years. Other potential advantages to on-bill repayment include (i) simplified underwriting standards based on utility bill repayment history, (ii) the potential to substitute displaced energy consumption with financing charges on one bill, (iii) added lender repayment security associated with utility-bill charges. It should be noted that on-bill financing is a loan servicing solution, and that funds to implement on-bill financing programs can come from various sources including utilities, third-party lenders, or public funds. On-bill financing has been widely discussed as an effective repayment tool for energy efficiency improvements and has been used by several utilities with some success. PV on-bill loan repayment is less common, but Hawaii is currently exploring implementing a solar on-bill financing program (IREC, 2011).

Loan Guarantees / Risk Insurance

Loan guarantees, risk insurance, loan loss reserves, interest rate buy downs and other credit support mechanisms may be effective tools for incenting private-sector lenders to support solar technology investments. While the specific policy design elements of these incentive types vary, they all have the common element of limiting or eliminating lender risk, thereby allowing private-sector lenders to provide capital to solar projects they might not otherwise support. In each of these incentive types, public money is used to leverage private-sector funds, sometimes significantly multiplying the effect of a relatively small amount of public money. One of the most notable solar loan guarantee program is the U.S. DOE's loan guarantee program. This federal initiative has provided loan guarantees for both manufacturing facilities and large-scale solar projects (U.S. DOE, 2011a). Additionally, the Massachusetts energy efficiency program administrators operate a successful interest rate buy-down program with Systems Benefit Charge funding that supports energy efficiency technologies (MassSave, 2011).

A2.3. Core Policy Mechanism Descriptions

This section supports the analysis in Section 9.4. It presents more detailed overviews and analysis of the three core policy mechanisms: standard offer PBIs, standard offer upfront payments, and quantity obligations. Each of the three mechanisms is characterized using the framework described in Section 9.3.3. The key policy design variations for each policy mechanisms are discussed and a more detailed description of policy strengths and limitations is included.

Standard Offer PBI Framework

Standard offer PBI incentive payments typically share the structural elements described Table 101 below.

Table 101. Standard Offer PBI Characteristics

DESIGN FEATURE	DESCRIPTION
Incentive type	Cash payments from the purchasing/interconnecting utility.[170]
Basis for incentives	Performance based, typically expressed as $/kWh.
Payment Duration	Standard offer PBIs payments are paid over time, and are often designed to provide generators with long-term (e.g. 15-20+ years) revenue streams.
Commodities transferred	To date, many Standard Offer PBIs have been designed to require that electricity, RECs, and other environmental attributes are purchased (and therefore transfer to the purchaser). This is not always the case[171], however, and potential policy variations are discussed in detail below.
Degree of revenue certainty	Standard offer PBI payment levels can be fixed over time, or can be indexed to vary according to inflation, electricity market prices, or other benchmarks.
Timing of revenue and access certainty	Standard offer PBIs are available on a standard offer basis, which means that the available incentive levels are published and known in advance, and that (subject to queuing rules in the presence of a quantity cap) generators can rely on access to a payment stream under the FIT if they are able to come on-line.
Setting the incentive level	Standard offer PBIs are set administratively (similar to rebates and to tax credits)

Key Design Variations

As discussed above, standard offer PBI designs vary widely. There have been numerous recent efforts to describe standard offer PBI design options (Couture & Gagnon, 2010; Grace, Rickerson, Porter, DeCesaro,

170 Some, however, have pointed out the similarities between some European feed-in tariffs and the federal Production Tax Credit in the US (Olz, 2008; Toke, 2005).

171 For example, the performance-based incentive in California does not involve the transfer of any commodities.

Corfee, & Wingate, 2008; Mendonca, Jacobs, & Sovacool, 2009). Rather than revisiting these studies in-depth, this section focuses on the design options that are the main differentiators between standard offer PBI policy variants.

- ***Rate setting basis.*** The two major approaches to standard offer PBI rate setting can be classified as cost-based or valued-based.[172] Cost-based rates reflect the generation costs of the target technologies, including a return on investment. Value based rates, in contrast, reflect the value of the energy delivered and are typically pegged to benchmarks such as utility avoided cost. The majority of standard offer PBIs are cost-based. Value-based rates for solar have historically been too low to support solar.[173] The Sacramento Municipal Utility District, however, recently set FIT rates for generators up to 5 MW at a rate defined as the avoided cost of natural gas generation plus adders for carbon benefit and grid benefits.[174] The queue was rapidly filled by 100 MW of megawatt-scale PV generation.
- ***Technology differentiation.*** Standard offer PBIs can be differentiated according to different technologies, sizes, applications, or other characteristics. [175] For PV, standard offer PBIs have been differentiated according to size (i.e. with higher rates for smaller systems), application (BiPV vs. standard installations), and irradiance level (i.e. rates adjust downward for stronger solar resource).[176]
- ***Incentive structure.*** Standard offer PBIs can be paid as part of a long-term contract for power, paid as a premium on top of wholesale prices (e.g. Spain and the Dominican Republic) or on top of net metering rates (e.g. California and Washington State), or calculated as the difference between the wholesale price and a fixed payment level (e.g. the Netherlands and Finland) (Couture & Gagnon, An

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172 NREL notes that an alternative pathway would be to base payments on neither cost or value (Couture & Gagnon, 2010). Such approaches have not had significant market impact to date. This study assumes that policy makers utilize some type of explicit methodology to set incentive levels.

173 There are a wide range of methods for calculating value-based rates. Several different reports have attempted to calculate the value of PV, for example, to society, to ratepayers and/or to the grid. These values include energy and capacity value, avoided transmission and distribution costs, avoided system losses, ancillary services, hedge value, air emissions and greenhouse gas reductions, and reduced water use, among others (Contreras, Frantzis, Blazewicz, Pinault, & Sawyer, 2008). A recent study led by researchers from SUNY, for example, estimated the value of PV to be between \$0.15/kWh to \$0.41/kWh (Perez, Zweibel, & Hoff, 2011). There have also been several studies of PV value in California (American for Solar Power, 2005; Smeloff, 2005), the most recent of which concluded that PV could have an additional value of \$0.078/kWh - \$0.127/kWh above the market price referent (i.e. avoided cost) in California (Schell, 2010). PV value calculations can vary widely, however, depending on which values are included, whether simply value or net value is calculated (i.e. subtracting out the costs of PV integration), and depending on location. A study from the Princeton Environmental Institute, for example, calculated that PV value in Northern Illinois was significantly higher than in southern California (Duke, Williams, & Payne, 2005).

174 California has several value-based standard PBIs in place, including a statewide feed-in tariff, the SMUD feed-in tariff, and a standard offer contract offered by Southern California Edison.

175 Standard offer PBI differentiation is similar in intent to creating tiers or carve-outs in RPS to support specific technology types.

176 Germany and Ontario differentiate systems by size, while France has rates both that are differentiated according to application type (BiPV vs. standard installations) and irradiance levels.

analysis of feed-in tariff remuneration models: Implications for renewable energy investment, 2010).[177] Long-term contracts provide greater investor security than premium payments, but premium payments can enable generators to participate in electricity market competition instead of being locked into long-term contracts.

- ***Commodities purchased/transferred.*** As discussed in Table 101, many standard offer PBIs are explicitly purchases of electricity, RECs, and (in some cases) other commodities. A potential variant of a standard offer PBI, however, could involve the purchase of only one commodity – such as RECs. New Jersey, for example, considered introducing a 15-year standard price for RECs as part of its solar market transition (N.J. BPU, 2007), but ultimately opted for other mechanisms (see New Jersey Case Study in Section 0 below). In Delaware, Delmarva Power and Light has applied to the Public Service Commission to procure SRECs using 20-year contracts (Goodman & Farnan, 2011).[178] The Public Service Commission in New York State also approved NYSERDA consideration of the use of standard offer contracts for RECs as part of the state renewable portfolio standard (RPS) compliance, but NYSERDA has not yet proposed such a mechanism (N.Y. PSC, 2006).
- ***Policy adjustments.*** A key component of standard PBI design is how the policies are adjusted in order to manage market growth and volume. Almost all countries with PV standard PBIs have some type of hard program cap in place.[179] The cap can serve as a hard stop or as a trigger for an automatic adjustment or a review. Some standard offer PBIs also have an automatic schedule of rate declines, known as a degression schedule. A more detailed discussion of policy adjustments is contained in Section 2.5 on cost control mechanisms.

Strengths and Limitations

This section reviews the strengths and limitations of standard offer PBI policies from the perspective of investors, ratepayers and policymakers. The high-level discussion below is meant to provide policymakers with a frame of reference on standard offer PBIs, but it should be noted that actual policy performance will depend heavily on a program's design details.

Investors

Strengths.

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177 This third approach is also known as a "spot market gap" structure. See Couture and Gagnon (2010).

178 Under the proposed pilot program, SRECs for systems 250 kW to 500 kW (Tier 2B) and systems 500 kW to 2 MW would be competitively procured. Systems under 50 kW (Tier 1) would receive $260/MWh for years 1-10 and $50/MWh for years 11-20. Systems 50 kW to 250 kW (Tier 2A) would receive $240/MWh for years 1-10 and $50/MWh for years 11-20 (Public Service Commission of the State of Delaware, 2011).

179 The exception to this is the Germany which has no caps. Germany, however, does manage its market volume by using price levels and adjusting its feed-in tariff rates in order to bring more or less PV into the market each year (DB Climate Change Advisors, 2011).

- Generators are assured a market for their electricity and RECs, which are typically purchased under a long-term contract with a creditworthy counterparty (e.g. a utility or a central procurement entity). The availability of a guaranteed price, buyer, and long-term revenue stream allows standard offer PBIs to create a high level of investor security, minimizing market risk and lowering the cost of capital (Corfee, Rickerson, Karcher, Grace, Burgers, & Faasen, 2010; Grace, Rickerson, Porter, DeCesaro, Corfee, & Wingate, 2008).
- The fact that generators do not have to compete for the standard offer PBI rate lowers project transaction costs, costs associated with competition and contract negotiation, and development risks (Goodman & Farnan, 2011). The low risk nature of standard offer PBIs lowers the cost of capital required to finance projects and lowers the overall policy costs(DB Climate Change Advisors, 2009).
- Because standing tariffs are less costly and less complex than competitive solicitations, they increase the ability of smaller projects or developers to participate in the market (Grace, Rickerson, Porter, DeCesaro, Corfee, & Wingate, 2008).
- Market access is enhanced because project timing is not constrained by rigidly scheduled solicitations, completion dates may not be constrained by contractual requirements, can be uncapped, and interconnection is typically guaranteed (Grace, Rickerson, Porter, DeCesaro, Corfee, & Wingate, 2008).

Limitations.

- Standard offer PBIs that are designed to maximize investor security can attract a significant amount of PV development. If PV policy caps are achieved too quickly or if more PV is developed that expected or intended, causing greater than anticipated rate increases, this can limit policy durability (SEMI PV Group, 2009) (Spain case study in Section 9.7).[180]As with other policies, standard offer PBIs can be designed to balance market growth with progress towards policy targets and can include automatic market adjustments, such as rate decreases or hard caps.

Ratepayers

Strengths.

- As discussed above, standard offer PBIs have the potential to minimize financing costs for PV projects and can therefore support installations at a lower cost than policy approaches that place a greater degree of market and development risk on generators.

[180] Both Spain and France significantly scaled back their programs after exceeding (or making unexpectedly rapid progress toward) their program caps (400 MW and 5400 MW, respectively). Germany, by contrast, has no hard program caps and projects that it will install 51,000 MW by 2020 (Federal Republic of Germany, 2010).

- Standard offer PBIs are also performance-based, which means that they use ratepayer money to pay for the production of actual electricity rather than just potential performance.
- The long-term fixed price contracts often associated with standard offer PBIs can serve as a financial hedge against volatile fossil fuel prices – particularly as PV costs continue to fall.

Limitations.

- Standard offer PBI rates are administratively set and policymakers can choose to set rates "too high.". If there is significant volume response to high rates, this can result in a corresponding increase in ratepayer impacts.
- Standard offer PBIs do not adjust automatically to account for changes in market prices. PV prices have been dynamic during the past several years (see Section 2.6) and policymakers have been challenged to "keep up" with the market and adjust rates accordingly.

Policymakers

Strengths.

- As noted above, studies indicate that standard offer PBIs can deliver a renewable energy generation at a lower policy cost than policies that utilize variable incentive payments.

  Standard offer PBIs can be employed in a targeted fashion to encourage specific types of projects, locations, sizes and technologies, if so desired (Grace, Rickerson, Porter, DeCesaro, Corfee, & Wingate, 2008).

Limitations.

- Getting the price right is challenging. If set too high, the tariff introduces the risk of overpaying and over stimulating the market. If the tariff is set too low to provide adequate returns to investors, it may have little effect (Grace, Rickerson, Porter, DeCesaro, Corfee, & Wingate, 2008). As a result, a significant amount of attention is required to both set the rate and adjust it over time in a manner that balances driving investment with ratepayer impacts, while maintaining the benefit of known price and availability to developers.
- Standard offer PBIs would be challenging to implement if there were not a unique buyer, e.g. the interconnecting utility offering the tariff and payments (Grace, Rickerson, Porter, DeCesaro, Corfee, & Wingate, 2008). Yet placing a requirement to purchase electricity on the distribution utility, for example, would be a philosophical departure from the competitive retail market environment in New York, in which the interconnecting electric distribution utility is not intended to be the lone generation

service provider, and where a customer hosting a solar project may purchase electricity from a competitive electric service provider.[181]

- Besides issues of economic efficiency, effectiveness or equity, a policy's success may also be determined by its institutional feasibility, or the "extent to which a policy instrument is likely to be viewed as legitimate, gain acceptance, and be adopted and implemented." (Mitchell, Sawin, Pokharel, Kammen, Want, & Fifita, 2011) Some jurisdictions may value project-on-project competition because they place a value on the process of competition. Under such circumstances, policies that do not require projects to compete, such as standard offer PBIs, may not align well with prevailing regulatory practice and ideology.

Standard Offer Upfront Payment Framework

Up-front incentive payments typically share the structural elements described in Table 102 below.

Table 102. Up-Front Payment Incentive Characteristics

DESIGN FEATURE	DESCRIPTION
Incentive type	Cash payments
Basis for incentives	Typically capacity based.[182]
Payment Duration	One-time, delivered at or near the beginning of project life.
Commodities transferred	Electricity is not purchased through rebate programs. The treatment of RECs, however, varies by state as discussed below
Degree of revenue certainty	As a buy-down, upfront payments provide a high degree of revenue certainty of the value of the incentive itself, since they are delivered near the beginning of the project, but provide no certainty for the remaining revenue required
Timing of revenue and access certainty	Upfront payments provide a high degree of revenue certainty because they are delivered near the beginning of the project and because access to incentives is clearly understood ahead of time (subject to program rules).
Setting the incentive level	Set administratively

181 In NY, this role is already filled by NYSERDA for the RPS, as a central procurement agent.

182 The majority of current state upfront incentives are awarded based on capacity (e.g. $/watt). California and Connecticut award payments based on expected performance. Illinois, Pennsylvania, and Puerto Rico each utilize a combination of capacity and costs to determine incentive levels. (DSIRESOLAR, 2011). None of the state rebate programs are calculated based on expenditure. At the federal level, the federal 1603 Treasury Grant is based on project expenditures.

Key Design Variations

The key design variations with upfront payments involve the basis for the upfront payment, timing of the payment, and the commodities that are transferred with the payment.

- ***Basis for the incentive.*** Up-front payments are most commonly applied on either a capacity basis (i.e. $/W payments) or an expenditure basis. It is also possible to use performance as the basis for incentives (Hoff, 2006). Upfront incentives, for example, can be based on the projected performance of the system – i.e. the forecast output based on factors such as system siting (Barbose, Wiser, & Bolinger, 2006). It is also theoretically possible to tie upfront payments to actual performance by holding back (or retroactively reducing) the upfront payment amount if the system doesn't perform.[183] In practice, the majority of states use capacity based incentives. Payments on an expenditure basis are less effective than capacity-based payments at establishing incentives for least-cost construction, as the former would pay more for a more expensive system.
- ***Timing of the payment.*** Upfront payments can occur at the time of system purchase or after system installation. Payments at the time of purchase are typically referred to as grants or "buy-downs" whereas payments that are made once the installation is complete are referred to as rebates (Gouchoe, Everette, & Haynes, 2002). Grants or buy-downs paid at the time of system purchase can reduce the amount of the outlay and financing by the system owner, whereas rebates may require that the owner invest or borrow the full system cost until rebate funds are received. If rebates require a project developer to seek a bridge loan, additional transaction costs would be encountered.
- ***Commodities transferred.*** Upfront payments do not typically involve a purchase of electricity. The treatment of RECs, however, varies from state to state. Some states such as California and Connecticut specify that RECs remain with the generator when the generator receives a rebate. In other jurisdictions such as Nevada and Puerto Rico, the REC transfers to the entity that provides the upfront payment (DSIRESOLAR, 2011). In New York and Oregon, RECs transfer to the entity that provides the incentive for a portion of a system's life (e.g. three years in New York) with REC ownership reverting to the generator for production occurring thereafter.

Strengths and Limitations

Investors

Strengths.

- Upfront payments create a high degree of investor security because they provide a known incentive in advance and a high degree of revenue certainty.

[183] The impact of upfront payments on the cost of electricity is also tied to the tax treatment of such payments, as more fully described in Section 1.2.3 (Barbose, Wiser, & Bolinger, 2006), Tax-free grants and rebates reduce either the project's deprecation cost basis and ITC, or the availability of PTCs.

Limitations.

- Similar to standard offer PBIs, upfront payments for PV can be quickly subscribed and raise questions about policy durability.

Ratepayers

Strengths.

- The net present value of the upfront payments required to provide generators with a target return for a certain quantity of PV capacity may be lower than the net present value of the performance-based incentives required to accomplish the same goals (Project Catalyst, 2009).
- Simplicity compared to participating in performance-based, market-based approaches.

Limitations.

- Upfront payments can create a higher initial "rate shock" for ratepayers than performance-based incentives paid over time, even if they are more cost-effective on a net present value basis.
- Upfront payments leave energy market price risk on investors, which may result in a risk premium to investors reflected in higher required upfront incentives than would otherwise be the case.

Policymakers

Strengths.

- Upfront payments are particularly useful for supporting early adoption of PV since they reduce the need for additional financing (e.g. loans) which may or may not be readily available, depending on market maturity. Moreover, upfront payments can be an effective mechanism to create incentives for innovators and early adopters to invest in PV systems without necessarily setting the upfront payments at levels that would provide commercial returns.

Limitations.

- Upfront payments require securing a source of funding. Existing policies of this type have typically been funded by systems benefit-type charges, such as New York's RPS charge, and in some cases, by alternative compliance payments from renewable energy quantity obligations or RGGI allowance revenues. Neighboring states (including New Jersey, Massachusetts and Connecticut) have realized the limitations of such a funding approach when it comes to supporting aggressive solar energy targets: (i) the need to authorize such funding approaches, particularly if it requires increasing the level of funding, is politically challenging; and (ii) such funding approaches may be interrupted or volatile, placing industry growth at risk. The three states cited have all shifted to a greater reliance on policies which rely on passing policy costs directly through to ratepayers, rather than policies that only rely on stand-alone funds, and mechanisms that include explicit and longer-term support for solar power industry (e.g. solar-specific targets and/or long-term contracts).

- Upfront payments that are not performance-based create the risk that generators will not maintain their systems once they achieve their return on investment. Still, upfront payments are often awarded to systems that receive additional revenue streams that are based on performance – such as behind-the-meter systems that generate utility bills savings for system owners, or in-front-of-the-meter systems that generate revenue from wholesale sales. These additional revenue streams serve to create incentives for performance even if upfront payments do not. Policymakers can also support system performance by requiring equipment and installation standards and warranties, inspections, 30-day test periods, and system monitoring (Barbose, Wiser, & Bolinger, 2006).

Renewable Energy Quantity Obligation Framework

Quantity obligation policies typically offer support to PV installations with the structural elements described in Table 103.

Table 103. PV Obligation Characteristics

DESIGN FEATURE	DESCRIPTION – SOLAR OBLIGATION WITH NO REVENUE STABILITY MECHANISMS	DESCRIPTION – SOLAR OBLIGATION WITH COMPETITIVE PROCUREMENT OR REC PRICE FLOORS
Incentive type	Cash payments from load serving entities	Cash payments from either (i) load serving entities or (ii) central procurement agent
Basis for incentives	Performance-based, representing payments for RECs, and in some cases associated electric energy (sometimes depending on whether generation is consumed behind the retail meter)	
Payment Duration	Restructured Markets: Generally on a spot basis.	Contract or price floor typically 10-20+ years
Commodities transferred	Typically conveying at least RECs, although RECs sometimes purchased bundled with electrical energy.	Typically conveying at least RECs; RECs often purchased bundled with electrical energy in regulated markets and sometimes under long-term contracting policies in restructured markets.
Degree of revenue certainty	None	Substantial with fixed payment levels over long-term contracts, depending on policy structure and co-policies utilized.
Timing of revenue and access certainty	n/a	Price floors: generally well in advance. Long-term contracting: only after successfully competing for contract.
Setting the incentive level	Level of payments set in commodity market.	Level of payments set competitively through solicitation mechanisms.

Key Design Variations

Quantity obligation policies have a wide range of design choices falling into three broad categories (Grace & Wiser, 2003; Wiser, Porter, & Grace, 2004):

Structure, Size and Application

- ***Structure.*** Quantity obligation policies can allow all eligible resources to compete head-to-head within a single tier, or with multiple tiers to achieve different purposes (i.e. both pre-existing and new renewables, both least-cost and emerging renewable energy technologies).
- ***Percent targets & timeframes.*** Quantity obligation policies vary in the specific targets (usually established as a percentage of load) and ramp-up schedules of the targets over time.
- ***Duration and stability of purchase obligation.*** Well-designed quantity obligation policies maintain the requirements for a sufficient duration to allow financing to occur. Some policies explicitly continue well beyond the target schedule while others are silent. Not specifying whether targets continue creates a perception of uncertainty that can impede financing in the absence of long-term contracts. (Wiser, Porter, & Grace, 2004).

Eligibility

- ***Geographic eligibility/delivery requirements.*** States have adopted a range of approaches to electricity delivery requirements to define geographic eligibility in line with the applicable policy objectives.[184] States have also used long-term contracting co-policies to influence geographic eligibility. Both approaches are constrained by the U.S. Constitution's 'Commerce Claus' limitation on restraint of interstate trade, which bars state policymakers from discriminating in favor of in-state suppliers (Elefant & Holt, 2011; Rader & Hempling, 2001). When eligibility is specifically targeted to require behind-the-meter installations or interconnection to the distribution system of an in-state utility, this will effectively limit most generation to in- state. New York's RPS, for example, requires that energy be delivered for use by load in New York as a condition of eligibility.
- Policymakers can influence the supply, demand and cost of compliance (e.g. REC prices) through their choices of ***resource type eligibility***. Because sudden expansions can destabilize REC prices, best practices dictate that policymakers maintain consistency in defining resource type eligibility, with changes under limited circumstances and with ample forewarning, to maintain an attractive environment for investment in eligible generation. States often target resource types (such as those

[184] Approaches to influencing the location of generation used for quantity obligation compliance are expressed in the policies' geographic eligibility and import rules. By adjusting the eligibility requirements for imported renewable generation, policymakers can either level or tilt the playing field in a variety of ways (Grace & Wiser, 2003). For a discussion of the options for defining RPS geographic eligibility and their implications, see Grace and Wiser (2002). For a summary of current approaches and examples of states that use them, see Wiser and Barbose (2008), Table 3.

with strong local manufacturing or resource presence) through their inclusion in high value quantity obligation tiers.

Administration

- ***Compliance verification mechanisms.*** Quantity obligation policies typically use either RECs or a combination of generation ownership and tracking of energy along contract paths as means to verify compliance. New York is one of the only markets not currently utilizing RECs as a compliance verification vehicle (N.Y. PSC, 2011c).[185]
- ***Enforcement mechanisms.*** With the exception of central procurement approaches, an effective quantity obligation typically establishes a mandatory requirement that imposes repercussions on LSEs that fail to meet the specified targets. Credible enforcement ensures that the quantity obligation is met, and that renewable energy investors can understand the risk of their investments (Wiser, Porter, & Grace, 2004). Penalties can take the form of financial payments, or suspension of a license to sell for competitive retail suppliers**.**
- ***Price or cost caps, alternative compliance payments (ACPs).*** A common form of penalty is an alternative compliance payment, a price at which obligated LSEs may make a payment rather than complying with a REC, which effectively doubles as a price cap. Effective REC price caps for new quantity obligation tiers are typically set at a multiple of the cost of compliance in order to incentivize renewable energy development, but serve to limit the cost of compliance to ratepayers in periods of shortage. Some quantity obligation policies establish a cost cap (reflected as a maximum retail rate impact) to limit the costs to ratepayers. While the impact may be similar to a REC price cap, it imposes some uncertainty over the cap's timing and application which can undermine investment.
- ***Flexibility mechanisms.*** Renewable energy development timing is difficult to control (e.g. due to permit appeals), production can very over time, and load obligations are difficult to predict (particularly in retail choice markets). Flexibility mechanisms such as banking excess compliance or RECs or adjustments to future target ramp-ups, can help markets participants adapt to supply-demand imbalance, and help mitigate price volatility.

Strengths and Limitations

Quantity obligations can differ substantially depending on design details as well as the presence or absence of supportive co-policies. Variations have been introduced over the past decade to address many of the

185 To date, New York has relied on a contract-path oriented environmental disclosure system, which allows for a limited degree of unbundling via 'conversion transactions' combined with contractual representations, for means of verification (N.Y. PSC, 2011c).

early US quantity obligation models' limitations.[186] The following discussion provides a high-level discussion of the strengths and limitations of quantity obligations models that do not include mechanisms to remove or reduce market volatility from the perspective of investors, ratepayers and policymakers. Mitigating design features are also introduced parenthetically.

Investors/Developers

Strengths.

- Creates demand, market
- Supports financing (especially in the presence of long-term contracting provisions)
- Low administrative burden

Limitations.

- Price volatility/instability, and difficulty financing without long-term contracting (mitigated by policy stability, price floor or long-term contracting mechanisms)
- Risk that the quantity obligation policy will be changed, curtailed or removed in a way that adversely impacts project revenue

Ratepayers

Strengths.

- Favors least cost commercial renewable energy technologies
- Uses competitive market structure to drive lowest-cost available eligible resources

Limitations.

- Market prices can spike during shortage (ACPs, price caps, etc.) or inflated by risk premiums from investors if no securitization mechanisms are present

Policymakers

Strengths.

- Low administrative burden for policies that rely on spot market REC trading. There may be higher administrative costs for quantity obligations that rely on competitive procurements.
- Fits both restructured and regulated markets

186 For example, original RPS concepts envisioned only tradable RECs without securitization mechanisms (Rader & Norgaard, Efficiency and sustainabilty in restructured electricty utility markets: The renewables portfolio standard, 1996).

- Policymakers know in advance the quantity of renewable energy that will be supported
- Competitively neutral

Limitations.

- Unknown cost (mitigated by cost caps, rate caps, flexibility mechanisms, etc,)
- Lack over control of where generation will be built (unless mitigated by eligibility restrictions)
- Little support for emerging technologies (mitigated by tiers, multipliers, contracting provisions, etc.)(Grace, Donovan, & Melnick, 2011)

A2.4. Best Practices

PV incentive best practices effectively balance the competing needs of multiple stakeholders while stimulating market growth. As the previous section indicates, there is a range of potential policy mechanisms that can be implemented to meet similar goals. Additionally, design aspects of each policy type can be used to minimize differences in incentive program outcomes. Given the wide range of policy choices, the following section will examine best practices from each of the previously defined perspectives (investor, ratepayer and policymaker), highlighting notable policies that have effectively addressed key concerns of solar market stakeholders using different policy mechanisms. It should be noted that state and federal government solar policy choices are highly context specific and policy design choices made by individual governments may not be applicable to New York.

Investor Perspective Best Practices

Given the significant role of state incentive programs in solar project financing, investor concerns are a critical factor in policy design. Poorly designed solar policy regimes may not successfully mitigate investor risks leading to limited capital deployment and high program cost. As outlined in section 3.1 above, a number of potential risks must be considered during any policy design process. Recent work by Deutsche Bank Climate Change Advisors described the project investor perspective as preferring policies that have "transparency, longevity and certainty"(DB Climate Change Advisors, 2009). Transparency is described as the ability to easily understand and navigate an incentive regime. Longevity is characterized as the creation of programs that provide support on a timeline that matches the investor's time horizon. Certainty is defined as providing a reasonable assurance that incentives are bankable over the life of the program. The following section briefly describes the Massachusetts SREC program and the design choices policymakers used in developing that program's regulatory rules in an effort to address investor and developer concerns. New Jersey's IOU long-term contracting programs and Germany's solar feed-in tariff, further discussed in section 3.6 of this report, are other successful policies that mitigate investor concerns about incentive program transparency, longevity and certainty.

The Massachusetts Solar Renewable Energy Certificate program uses a series of innovative design mechanisms to establish an SREC market price floor intended to provide investors and developers with long-term price security. This program launched in early 2010 and is intended to support the development of 400 MW of PV over the course of the next decade. Through a series of intricate design mechanisms, the program attempts to establish an SREC price floor by granting generators eligibility to deposit un-sold SRECs in a "last chance" certificate auction at the end of each compliance year. The certificate auction is designed to clear at the market floor price of $300 per MWh[187], and, while LSEs are not obligated to purchase certificates from the auction, a series of future LSE obligation triggers is incorporated into the program regulations that highly incentivize LSEs to purchase certificates from the auction. PV system investors are assured eligibility in the last-chance auction for a period of between five and 10 years depending on market conditions, effectively giving long-term minimum price certainty to generators before the project is completed.[188]

While project developers were initially skeptical of the program's complex rules and triggers, to date, more than 27 MW have been developed under the program with close to 1,000 installations qualifying for SREC eligibility (Mass. DOER, 2011). National solar developers have also become active in the Massachusetts market as they have become more comfortable with the SREC market's regulatory complexity.[189] It should be noted that, as an early stage SREC market, the Massachusetts market is currently under-supplied, meaning that the SREC last-chance auction mechanism has not yet been activated.

Ratepayer Perspective Best Practices

As the funders of solar incentive programs, ratepayers have a unique perspective on appropriate solar incentive program design. The primary ratepayer concern involves exposure to unexpected or uncontrolled program costs and assuring least-cost development of solar resources. This topic is discussed in detail in section 3.6. In addition to policy cost issues, policies that account for ratepayer perspectives can consider system performance assurance and consumer protection as well as equity concerns related to distribution of program benefits (DSIRE Solar, 2011e). Policy mechanisms that focus on system performance are designed to assure that incentives promote properly sited, installed and maintained PV systems while also helping build the credibility of the technology in the marketplace. Poorly designed incentive programs risk

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187 Note: The Mass. DOER charges a $15 per MWh administrative fee on certificates deposited in the auction account, effectively reducing the price floor to $285 per MWh.

188 The mechanics of the Massachusetts SREC program are highly complex and a full discussion of this program is beyond the scope of this report. More information on the program is available at: http://www.mass.gov/?pageID=eoeeasubtopic&L=5&L0=Home&L1=Energy%2C+Utilities+%26+Clean+Technologies&L2=Renewable+Energy&L3=Solar&L4=RPS+Solar+Carve-Out&sid=Eoeea

189 National residential third-party financiers Sun Run, Sungevity and Solar City have entered the Massachusetts market in the past year.

providing subsidies that promote non-functioning PV systems, negating many of the societal benefits of PV installations and risking consumer backlash for this largely unfamiliar technology. Policymakers have also used solar policy design parameters to promote more equitable distribution of program benefits. In many states, non-profit and local government ratepayers provide significant contributions to funding solar incentive programs, but may not be able to cost-effectively take advantage of PV installations as federal incentives (the ITC and depreciation credits) cannot be monetized by non-taxable entities. As a result, policymakers in some states have developed programs that provide additional support to non-taxable entities. Similarly, policies in other states have been developed to ensure that incentives for low and moderate income ratepayers are sufficient to support installations in that residential sub-market.

Performance-based incentives, such as those in the New York Regional program, which compensate project owners and developers based on energy generated instead of capacity installed or total investment, are the most effective policy tool for ensuring appropriately sited, installed and maintained PV systems. Under a PBI, incentives are only available for actual system production. As previously mentioned, PBIs have been successfully implemented both by U.S. states and national governments internationally and are an increasingly popular policy option for state policymakers (DSIRE Solar, 2011e).

Policymakers have implemented solar incentive programs that meet strategic equity goals using several mechanisms. For instance, in Massachusetts, residential systems can qualify for both upfront rebates and SREC market participation. The rebate program is structured to provide added incentives to homeowners with moderate or low income or with moderate to low home values. Other states have structured rebate programs tailored to support the non-profit and public-sector solar markets. Illinois, Pennsylvania, Nevada and Delaware have all implemented solar rebate programs with increased non-profit incentives (DSIRE, 2011d). While PBI additions are not common in the U.S., internationally, Ontario has designed its feed-in tariff to support equity goals by offering increased tariff payments for renewable energy systems developed by aboriginal tribes or under a community ownership model (Ontario Power Authority, 2011).[190] New York's RPS approach is strictly budget-limited, avoiding cost containment concerns.

Policymakers Best Practices

Many of the best practices implemented to meet policymaker and program administrators' goals may overlap with either investor or ratepayer best practices. Typically, incentive design goals such as minimal administrative burdens and program simplicity are a benefit to all solar market stakeholders, while others, such as flexibility, may or may not be supported by other market stakeholders depending on design and implementation specifics (Summit Blue & RMI, 2007).

190 Under the directives of the Public Service Commission, the NY program has been strongly driven by the desire to protect ratepayers and as such as developed fairly tight budget control mechanisms.

One policymaker best practice involves limiting administrative burdens and program complexity by adopting solar incentive policies that can be effectively integrated into existing administrative and regulatory frameworks. Many of the exiting solar set-asides in the U.S. use existing tracking platforms to measure and monitor program performance. In New Jersey, the SREC market uses the PJM-EIS GATS system provided by the regional transmission operator to track system production.[191] This system is also used by a number of other states (Pa., Ohio, Maryland, Del. and DC) track both solar credit generation as well as main-tier RPS generators. Additionally, well designed solar incentive programs that limit administrative costs are typically designed to easily integrate into existing electricity market structures. This is one of the primary goals of the existing New York RPS program.

A2.5. Cost Control Mechanisms

The recent dynamic reductions in PV installed costs and the rapid scale-up of PV markets in Europe under standard offer PBI policies has focused policymakers on strategies for controlling PV policy costs. Several recent reports have focused specifically on cost control strategies for PV standard offer PBIs (DB Climate Change Advisors, 2011; Kreycik, Couture, & Cory, 2011). The same cost control principles that apply to standard offer PBIs, however, are also broadly applicable to all PV policies. Generally, there are two strategies for controlling policy cost: controlling market volume (i.e. the amount of PV that is installed) and controlling market price (i.e. the amount that PV generators get paid). It is also important to note that these two approaches are closely related in that controlling the price that generators receive can also control market volume since lower prices reduce the number of projects that viably be built. This section provides overviews of the cost control mechanisms that are in common use for each of the major policy types.

Standard Offer PBI Cost Control Mechanism

- **Price controls**. The most straightforward cost control strategy is to set conservative, rather than aggressive, rates at the outset of the policy in order to provide incentives only for the most competitive plants to be built (Gifford, Grace, & Rickerson, 2010). Different policymakers have different philosophies about whether PV incentives should be inclusive of a broad range of projects or restricted only to the lowest cost projects, but many current PV standard offer PBIs are designed with mechanisms that can place downward pressure on prices. In the past, this has typically been accomplished through the establishment of pre-set schedule of automatic price decreases, known as a degression schedule. The automatic decrease occurs after the passage of a certain amount of time (e.g. one year) or after a certain amount of capacity has been installed or reserved (e.g. 100 MW). Germany

191 PJM-EIS GATS is the online generation attribute tracking system for the PJM independent system operator. PJM is the grid operator for much of the mid-Atlantic.

uses time-based degression, whereas California has used capacity-based degression for its PV incentives. As PV costs have rapidly decreased during the past several years, policymakers have introduced more complex and reactive degression schedules. Germany, for example, has introduced a series of planned decreases whose magnitude is tied to the PV capacity installed in prior periods such that the rate decreases faster if the market grows more than anticipated. Even with this adjusted degression, however, Germany has joined several other countries and states to conduct an "off-cycle" rate adjustment to account for rapidly declining prices (DB Climate Change Advisors, 2011). Both Spain and Oregon (Oregon P.U.C, 2011) have established a mechanism that adjusts rates depending on quantity and timing of developer response to a current price. If periodic program capacity allotments are reached quickly, the price is dropped for the next allotment. Conversely, if less than the allotment goes unfulfilled within a specified timeframe, prices are adjusted upwards (Kreycik, Couture, & Cory, 2011).

- **Volume controls**. Almost all PV standard offer PBIs utilize an overall capacity cap[192], and many also use interim capacity caps in parallel.[193] Ratepayer impact or electricity generation (e.g. 10% by 2020) caps could also be utilized. The introduction of caps in a standard offer PBI – whether capacity, cost, or generation based – requires the introduction of queuing protocols that govern how generators "get in line" and "stay in line" (Grace, Rickerson, Porter, DeCesaro, Corfee, & Wingate, 2008).
- **Review.** Many standard offer PBIs also involve a periodic review (e.g. every 2-4 years) that can be used to adjust the policy framework. Reviews can be used to adjust price, to adjust volume controls, or to amend broader policy issues (e.g. technology eligibility).

Upfront Payments Cost Control Mechanisms

The menu of potential cost control mechanisms for upfront payments are essentially the same as for standard offer PBIs. Upfront payments can be controlled through conservative price setting, automatic degression, program caps, and program reviews. A distinguishing feature of upfront payments is that they are typically supported through the creation of a Public Benefits Fund (PBF), or other mechanism, which has a finite budget. Caps on the overall and/or annual amount that can be collected under the PBF can be a strategy for controlling PV policy costs.

Quantity Obligation Cost Control Mechanisms

The establishment of volume limits is central to quantity obligations. The establishment of overall and annual targets sets up the framework in which the obligated entities must procure RECs. Beyond the overall

192 The primary exception to this rule is Germany. Germany has not utilized capacity caps since it amended the national Renewable Energy Law in 2004 (Jacobs, 2010).

193 The City of Gainesville, FL, for example, has an overall programmatic cap of 32 MW and a cap of 4 MW on the amount of capacity that can be installed annually.

target, however, the different procurement strategies each employ different cost control mechanisms.

Quantity obligations with REC trading, but no revenue stability mechanism

Price controls. In theory, quantity obligations deliver the lowest price by requiring price competition between generators (Rader & Norgaard, Efficiency and sustainabilty in restructured electricty utility markets: The renewables portfolio standard, 1996). As empirically documented in a range of recent studies and discussed in Section 9.3.1, however, the volatility inherent in tradable REC markets may actually drive policy costs up because of the financial risk premium required by investors. Most REC markets rely on several strategies in parallel with price competition in order to control costs.

- ***Generator eligibility***. Generator eligibility can be defined either narrowly or broadly (Grace & Wiser, 2003). Broad definitions expand the number of potential participants in the market. For example, eligibility might be defined to allow generators from other states in the region to also participate in the market, rather than restricting eligibility to within the boundaries of the state (Farell, 2011). Expanding eligibility to additional types of supply will inevitably shift the supply-demand balance and lower price. Broader eligibility increases the number of potential suppliers, thereby increasing competition and putting downward pressure on price. Such action, if not taken deliberately and with substantial notice, signals political instability that can destabilize markets and discourage investment (Wiser, Porter, & Grace, 2004).
- ***Alternative compliance payments (ACPs) or penalty payments***. Six states have implemented solar alternative compliance payments that obligated entities can pay in lieu of procuring SRECs from the market (Wiser, Barbose, & Holt, 2010).[194] ACPs are typically expressed as a $/kWh payment level and effectively serve as a price cap on the price of RECs and a cap on overall compliance costs. Several of the solar ACPs are also scheduled to decline over time, steadily restricting the price range in which RECs can trade. Several other states have established similar $/kWh payments for non-compliance but have set them up to be penalties that are not recoverable from rates. These penalties also have the effect of capping REC prices, but have different implications for utilities and ratepayers.

Volume controls.

- ***Quantity targets***. The overall amount required under a quantity obligation, which is typically expressed as a share of total generation, effectively serves as cap on the volume of projects that are installed. There are usually annual targets as well which serve as interim caps on volume growth.

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194 ACPs are considered a legitimate form of compliance and are not considered a penalty payment for failing to comply.

- ***Rate caps***. In addition to setting state targets, seven states[195] have established rate impact limitations for their quantity obligation policies, and four states[196] have established rate impact limitations specifically for solar (Wiser, Barbose, & Holt, 2010).

Quantity obligations with REC trading and a price floor

The price control strategies for quantity obligations with REC trading and price floors are the same as policies without price floors. The primary difference is that the price floor provides another lever with which to attempt to control costs. Since bankers deeply – or entirely – discount the value of tradable RECs, the price floor is used as the basis for establishing project bankability. Depending on the relationship of the price floor level to a project's generation cost, raising or lowering the price floor could have the opposite effect on policy cost. When the price floor is below generation cost, developers and investors lack revenue certainty:

- raising the price increases revenue certainty, lowers financing costs, and can therefore lower overall policy cost.
- lowering the price floor increases generator exposure to REC volatility, raises the cost of capital, and increases policy cost.

If the price floor is above generation cost, then the project enjoys excess profits.

- Raising the price floor increases the profit that a generator is able to achieve, thus increasing policy costs
- lowering the price floor decreases generator profits and lowers policy costs.

Quantity obligations with competitive procurement under long-term contracts

Price controls

- **Procurement design**. The intent of competitive procurement mechanisms is to create price competition between generators. There is a broad range of different structures for competitive procurement, and the type of competition created will depend heavily on the design of the procurement itself
- **Benchmark prices**. Under some types of competitive procurement (e.g. pay as bid), a benchmark price can be established above which contracts will not be awarded. This serves as a price ceiling and cost cap for the policy. New York and Illinois both apply this approach in their renewable energy central procurements

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195 CO, IL, MO, NC, NM, OH, OR

196 DE, MD, NJ and NM

- **Tier differentiation**. Although some competitive procurements are open to a broad range of different project types, others restrict eligibility to certain types of generators. Creating tiers that enable only the most cost-competitive projects to participate can be used as a cost control strategy

Volume controls

- **Fixed budget**. A budget can be allotted for each competitive procurement round which will limit the total amount of new capacity that can be built. NYSERDA's finite collections currently serve as a budget to control costs under its MT and CST central procurement mechanisms
- **Caps**. Related to the use of a fixed budget, auctions can also be capped based on capacity or total generation procured
- **Frequency and size**. Costs can also be controlled by holding infrequent and small competitive procurements. This option is less relevant for the current report since limited procurements would likely not be sufficient to produce the amount of solar envisaged for New York State.

The impact of the different cost control strategies on the market will vary depending on their designs. A common evaluation criterion for cost control strategies, whether they are used for standard offer PBIs, upfront payments or quantity obligations, is their transparency. Cost control mechanisms that are opaque or otherwise create uncertainty serve as deterrents to investors. Cost control mechanisms that have clear and transparent rules and are perceived by the market to be credible and stable can minimize impact and support policy durability without undermining investor confidence. Policies that use caps, for example, can be supported by clear and transparent queuing procedures and by publicly accessible registries of projects and/or other tools to allow the market to monitor progress toward the cap. A recent report from Deutsche Bank concluded that price controls that require automatic declines after a period of time elapses according to a known schedule provide the highest degree of transparency. The same study found that the use of capacity caps is preferable to the use of generation or rate caps since project caps can be actively monitored by both policymakers and market participants, where rate caps and generation caps can typically only be evaluated retroactively(DB Climate Change Advisors, 2011).

A2.6. Case Studies

The following section examines three globally significant PV markets with unique program and market structures. Germany is the leading PV market in the world and German incentive policies have created a stable solar market with installed costs expected to reach grid parity in the next several years. Spain's PV program is notable for the challenges it experienced during later part of the last decade when it experienced a market boom and followed by a sharp industry contraction. The New Jersey market is also profiled. Over the past few years, New Jersey has consistently been the largest east coast solar market and is also one of the longest running solar quantity obligation programs in the U.S.

Case Study: Germany

Germany is the global leader in cumulative PV installations, and accounts for 44% of the world's global PV capacity (REN21, 2011). For six of the last seven years, it has added more solar capacity to the grid than any other country. In 2010 Germany installed 7.4 GW of PV, for a cumulative total capacity of 17.3 GW nationally (AGEE Stat, 2011). PV supplied 2% of national electricity in 2010 and is on track to supply 3% of national electricity in 2011 (Chrometzka, 2011). Growth of its PV market is expected to continue: according to Germany's National Renewable Energy Plan, the country will have 51 GW installed by 2020 (Germany, 2010).

With the support of a strong policy climate and renewable energy targets, growth of Germany's PV and broader renewable energy market has been driven by the federal government's feed-in tariff policy. First targeting PV with generation-cost based rates in 2000, the feed-in tariff provides generators a 20-year contract at rates based on the cost of PV generation, which provide solar market players with stable prices and a reasonable rate of return sufficient to grow the market.[197] Though specifics of the solar feed-in tariff policy have been restructured a number of times over past decades, it has consistently provided the market transparency and certainty required to drive demand for solar power. Additionally, the policy has been developed with a degression schedule, which drives down the cost of solar energy over time. As discussed below, Germany has comparatively low rates for PV. The market is not subject to hard capacity caps, however, and so it has recently served as a backstop for the global solar market, absorbing excess global solar panel capacity.

Finally, Germany's solar policies have led to development of a robust solar manufacturing industry, creating over 64,700 jobs in the solar industry by 2009, the vast majority of which went to skilled trades (80.3%) or to individuals with university degrees (24.4%)(van Mark & Nick-Leptin, 2010). Leading global solar component firms – such as SolarWorld AG, SMA Solar Technology AG, and Q-Cells – are both headquartered and have major manufacturing facilities in Germany (DB Climate Change Advisors, 2011). Solar industry job growth is expected to increase in coming years as Germany aims to increase its export potential (van Mark & Nick-Leptin, 2010). The development of an internal solar manufacturing base is an explicit goal of the German solar feed-in tariff (Nitsch, Krewitt, Nast, Viebahn, Gartner, & Pehnt, 2004).

Policy Type and Goals

Germany's solar feed-in tariff has been structured to enable the country to meet aggressive climate and renewable energy goals. As a member of the European Union, Germany is subject to the 20-20-20 goal,

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[197] From 1990-2000, PV was eligible for a payment set at 90% of the retail rate of electricity, which fluctuated between 8.45 and 8.84 Eurocents/kWh during that time period. This rate was insufficient to support significant PV development (DB Climate Change Advisors, 2011). During this same period a number of German municipal utilities such as Aachen and Hammelburg did offer generation cost based rates, which contributed to the development of local markets (Solarenergie-Forderverein, 1994).

which aims to reduce greenhouse gases by 20%, reduce energy consumption by 20%, and increase renewable energy use to 20% across member states by 2020. Actual targets for each country vary (depending upon their ability to contribute to the broader goal), with Germany subject to some of Europe's most aggressive targets.

For example, Germany has established (i) a national mandate to reduce greenhouse gas emissions by 40% below 1990 levels by 2020 and (ii) a national mandate to derive *at least* 35% of electricity from renewable energy sources by 2020. In addition, it has also established aggressive goals for renewable heating and energy efficiency (BMWI & BMU, 2010).

While the country does not have *binding* targets specifically for solar or other renewable electricity technologies, PV is nevertheless an essential part of Germany's strategy to meet it GHG reduction and renewable energy goals. Like other EU members, Germany was required to develop a National Renewable Energy Action Plan (NREAP), which serves as a planning document outlining how the country will meet its climate and energy goals. Under the NREAP, Germany projects that solar will be one of the fastest growing renewable energy technologies, accounting for 19% of the total renewable electricity portfolio and 7% of the national electricity portfolio by 2020 (Germany, 2010).

Feed-in Tariff Policy Structure

The feed-in tariff is designed to enable Germany to meet its aggressive energy and climate goals and is explicitly linked to the floor target of 35% by 2020. To this end, the feed-in tariff provides PV project developers three key elements, which have driven robust market growth: (i) guaranteed priority access to the grid, (ii) a 20-year long-term contract for energy production, and (iii) an energy rate based on the cost of PV generation that affords a reasonable rate of return (targeting an IRR between five and 9% (Gifford, Grace, & Rickerson, 2010). Of these, the priority access to the grid provides particularly powerful support, including:

- **Guaranteed interconnection.** Utilities must interconnect all renewable generation to the grid, and must strengthen, upgrade, and/or extend the grid as necessary to accommodate new projects
- **Interconnection cost allocation.** Renewable energy generators bear the costs of interconnection up to the interconnection point. The costs of upgrading the grid to accommodate renewables, however, is borne by ratepayers
- **Guaranteed purchase.** Utilities must purchase 100% of the renewable electricity offered, similar to a "must take" obligation. Generators, however, may opt for several different sales options and may change their sale pathway monthly
- **Guaranteed dispatch.** Renewable energy must be dispatched as "must run" facilities ahead of all conventional generation in the economic merit order. The exception to this rule is if priority dispatch

for renewables endangers the stability of the grid. In this case, intermittent renewable generation can be curtailed

- **Curtailment compensation.** If renewable generation is curtailed, generators may be compensated for the electricity they generate under certain conditions (Rogers, Fink, & Porter, 2010; Rutschmann, 2011).

Additional policy elements are detailed in Table 104 below using the framework from Section 9.3.3.

Table 104. German Feed-in Tariff policy Framework Evaluation

POLICY FRAMEWORK CATEGORY	GERMAN FEED-IN TARIFF PROGRAM FEATURES
Incentive type	Cash payment
Basis for incentives	Performance-based
Timing of incentives	Paid over time through a 20 year contract
Degree of revenue certainty	High; guaranteed purchase and interconnection with priority dispatch
Timing of revenue certainty	Payment rates are known pre-construction
Commodities transferred /purchased	Electricity
Setting the incentive level	Administrative; sliding FIT system geared to annual installation volume

In order to incent the deployment of a diverse PV market that includes small residential systems along with large ground mounted arrays, the German incentive program includes tariff rates differentiated by system size and type. Table 105 shows the current German tariff rates for all PV system classes.

The majority of the PV systems installed in Germany to date have been small rooftop systems. The market share of larger, ground-mounted systems has increased each year, but smaller systems continue to account for the largest amount of new capacity. In 2010, for example, 4.3 GW of installed capacity – or 58% of the total for that year – was 100 kW or smaller and 2.5 GW was 30 kW or smaller (Chrometzka, 2011).

Table 105. German PV Feed-in Tariff rates (€/kWh) 2010-2012 (German Energy Blog, 2011)[198]

SYSTEM TYPE	SYSTEM SIZE	OCT - DEC 2010 €($)	JAN - JUN 2011 €($)	JUL - DEC 2011 €($)	2012 €($)
Ground Mount	<30 kW	0.24 (0.32)	0.21 (0.28)	0.21 (0.28)	0.19 (0.25)
	30-100 kW	0.24 (0.32)	0.21 (0.28)	0.21 (0.28)	0.19 (0.25)
	100-1000 kW	0.24 (0.32)	0.21 (0.28)	0.21 (0.28)	0.19 (0.25)
	>1000 kW	0.24 (0.32)	0.21 (0.28)	0.21 (0.28)	0.19 (0.25)
Rooftop	<30 kW	0.33 (0.44)	0.29 (0.39)	0.29 (0.39)	0.24 (0.32)
	30-100 kW	0.31 (0.42)	0.27 (0.36)	0.27 (0.36)	0.23 (0.31)
	100-1000 kW	0.3 (0.40)	0.26 (0.35)	0.26 (0.35)	0.22 (0.31)
	>1000 kW	0.25 (0.33)	0.22 (0.29)	0.22 (0.29)	0.18 (0.24)

Under the German feed-in tariff, transmission system operators are required to purchase power from tariff-eligible PV systems. Funds to support tariff payments are charged to ratepayers through their distribution companies. At the end of each year, ratepayer costs are trued-up to match tariff-eligible energy production to ensure that costs are equally distributed among ratepayers.

In 2008, Germany also permitted non-utility entities to purchase electricity from solar and other renewable energy producers. In this case, solar energy producers may structure bilateral contracts with third parties, like municipalities, on a monthly basis. Investors, in particular, favor this option. According to the US National Renewable Energy Laboratory (NREL),

> Customers in good standing and with solid credit can increase the certainty of revenue streams; and, in cases where premium-price policies are used, this option can provide a purchase guarantee that is generally not included within the policy framework. In addition, this option allows RE generators to sell electricity directly to customers at rates that may be lower than the retail price offered. This may provide benefits for consumers without significantly increasing the risks for producers (Couture, Cory, Kreycik, & Williams, 2010).

Evolution of the German Market and PV Policies

The German market has typically grown at a rate between 40 to 80% annually since 2000 with two notable exceptions of 144% in 2001 and 154% in 2004. PV market growth in Germany has been steady and tariff payment adjustments have trended downward over the course of the feed-in-tariff policy.[199]

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198 Dollar figures used in this section are approximate, based on Euro to U.S. Dollar exchange rates in effect during early December 2011.

199 Different feed-in tariff rates are available, based on rate differences for capacity and/or application.

The first iteration of the German feed-in tariff was passed in 1990 and had a program cap, requiring utilities to purchase up to 5% of their total power supply from renewable energy sources. FIT payments for further installations were passed on to the transmission operator. In 1998, an amendment added a second 5% cap in order to protect the costs to the transmission operator. The FIT policy of the 1990s resulted in minimal market growth.

The second iteration of the German feed-in tariff came in 2000 and guaranteed tariff payment for the first 350 MW of installed PV. The policy favored small installations by applying a five MW system capacity limit. The 2000 law also differentiated between roof-mounted and ground-mounted installations, placing a 100 kW size limit on ground mounted plants. This policy feature was implemented to avoid widespread installation on farm land and to encourage the development of small and distributed generation sites. Prior to reaching the 350 MW cap, the German government adjusted the limit in June 2002 up to 1,000 MW.

In 2003, Germany completely removed the program size cap for PV and an additional revision of the law removed the plant-size cap for PV installations in 2004. However, ground-mounted systems still have to comply with additional criteria not required by roof-top systems in order to become eligible for tariff payments.

The 2009 amendment created a flexible degression system in which the tariff rate is lowered as certain volume targets of PV installations are met. This mechanism is described in detail in the next section.

Cost Control Mechanism

As described above, Germany has used a variety of mechanisms to control PV costs in the past, including generation caps and capacity caps. The German FIT is not currently capped and the German government instead uses price levels to control PV market volume (DB Climate Change Advisors, 2011). Between 2000 and 2009, the German solar feed-in tariff included automatic, annual degressions as a transparent method of putting downward pressure on prices. The 2009 policy revisions included a new flexible degression system that had the goal of throttling the market based on market conditions. The new mechanism adjusts the tariff rate downward in future periods by an amount pegged to market performance. Under current laws, if the German solar market installs more capacity than the projected baseline installations during a particular quarter, the next scheduled PV tariff degression will be larger than the baseline degression. Similarly, if the market is undersubscribed, the tariff will not decrease. Table 106 displays the tariff degression schedule for 2012 (DB Climate Change Advisors, 2011). This flexible degression mechanism attempts to make future tariff prices transparent while still reacting to global PV market dynamics. Based on market growth in 2011, the German government recently announced that rates would be cut by 15%.

Table 106. German PV Feed-in Tariff Degression Schedule

SCENARIO	PROJECTED MW INSTALLED IN 2011	INTERIM (JULY 2011) DEGRESSION	TOTAL DEGRESSION (JANUARY 2012)
-2 GW	1,500	0%	2%
-1.5 GW	2,000	0%	4%
-1 GW	2,500	0%	7%
Base Case	3,500	0%	9%
+ 1 GW	4,500	3%	12%
+2 GW	5,500	6%	15%
+3 GW	6,500	9%	18%
+4 GW	7,500	12%	21%
> +4 GW	>7,500	15%	24%

Even with the flexible degression system, the German federal government has implemented several unscheduled tariff rate reductions in response to rapidly changing solar market conditions during 2009-2010. This occurred in July 2010 when the PV tariff rates were reduced by up to 13% (depending on system class) and again in July 2011 when PV rates were decreased according to the level of PV installed during the first quarter of the year. These unscheduled rate reductions have not led to a significant exit of investors from the German market. The German feed-in tariff program also has regular four-year program reviews which serve as an additional opportunity for appropriate regulatory oversight.

Lessons Learned

The German solar feed-in tariff policy has created the world's largest PV market. The certainty and long-term stability of the German market has created a significant export industry and a backstop market for global PV sales. This stability has also created one of the lowest installed-cost PV markets in the world. Average PV market prices in 2010 for Germany were about 40% below similar installed costs in the United States overall, and installed costs for small residential systems in Germany ($4.2/watt) were 64% lower than in the U.S. ($6.4/watt)(Barbose, Darghouth, Wiser, & Seel, 2011). Germany installed costs have continued to fall as panel prices have collapsed, with average installed costs in Q2 of 2011 reported as $3.3/watt (Chrometzka, 2011). A lesson learned is that increased market scale can unlock significant economies of scale with regard to installed costs (Barbose, Darghouth, Wiser, & Seel, 2011).

This stable, policy-driven market has also created conditions in which PV tariff payments may soon reach parity with retail electricity rates. Starting in 2012, the tariff rate 30 kW or smaller roof-mounted PV systems is expected to be € 0.261, roughly equivalent to the retail cost of power for homeowners (Energy.EU, 2011). Deutsche Bank analysts are also predicting that rising German retail electricity prices will cause all classes of German PV feed-in tariffs to be at or below retail electricity costs by 2012. It should be noted that European retail electricity prices are significantly higher than prices in New York with average household retail rates in German averaging $0.32 per kWh (€0.238) in 2011 (DB Climate Change Advisors, 2011).

The German feed-in tariff has been praised by investors for its transparency, longevity and certainty that have driven down financing costs and supported stable, long-term investment by installers and manufacturers (DB Climate Change Advisors, 2011). The policy has resulted in a robust solar manufacturing sector, although market competition for low-cost Asian suppliers has challenged German manufacturers.[200] Additionally, the un-capped nature of the market has given project developers confidence that incentives will be available leading to lowered financing costs and greater market stability.

Germany has conducted a cost benefit analysis of its feed-in tariff programs on an ongoing basis for several years, including a separate focus on direct impacts, transfer payments, and macro-economic impacts (DB Climate Change Advisors, 2011). The most recent calculations of the direct costs of the feed-in tariffs are included below. PV costs are not explicitly broken out, but the German government notes that a significant driver of the $2.5 billion increase in the cost of incremental electricity from 2009 to 2010 was as a result of the dramatic increase of PV installations (Breitschopf, Sesfuss, Klobasa, Steinbach, & Ragwitz, 2011). In 2010 alone, Germany installed 7,400 MW of PV capacity.

Table 107. 2010 Costs of the German PV Feed-in Tariff

DIRECT COSTS (MILLIONS)	
Incremental cost of electricity	€8,100 ($ 10,851)
Balancing electricity[201]	€385 ($516)
Grid expansion / upgrades[202]	€60 ($80)
Administrative costs	€27 ($36)
DIRECT BENEFITS	
Environmental benefits	€ 5,800 ($ 7, 700)

The German government also explicitly tracks transfer payments within the economy created by the feed-in tariff. For example, the wholesale price suppression effect of renewable electricity in Germany ("the merit order effect") created a €3.1 billion ($4.1 billion) savings in 2009, which represents a transfer from utilities

200 Photon's August 2011 module price index reports spot market prices for German and U.S. manufactured panels at $1.30/watt, with Asian manufactured panels (excluding Japan) cost $1.02/watt.

201 Balancing electricity refers to the cost of the additional electricity that needed to be purchased to compensate for the intermittence of renewable energy

202 Grid expansions refer to the fact that generators are guaranteed interconnection in Germany and that the cost of the required grid upgrades are allocated nationally.

to consumers. Similarly, renewable electricity generated €1.2 billion ($1.6 billion) in new taxes paid to governments from renewable generators.

Another critical lesson learned from the German feed-in tariff experience is the importance of well differentiated rate classes for different system sizes and types. The German tariff structure has created a diverse PV market with a wide range of system sizes, from small roof-mounted installations to utility-scale generators. This size diversity has allowed a wide range of German society to participate in the tariff program.

The growth of the German solar market has also created unique conditions in EU wholesale electricity markets. On July 16 of 2011 industry publications report that spot market electricity prices in the EEX during day-time peak hours dropped below typical night-time prices as renewable energy generators significantly reduced the need for fossil generation (Beneking, 2010; Rutschmann, 2011). While wind power had some contribution to this event, the 17 GW of installed German PV capacity was a significant factor in the shaving of the daytime electricity price peak. Because, under the German feed-in tariff laws, renewable resources are subject to guaranteed dispatch, PV generators can reduce the number of peaking facilities that must be brought online during the high-demand daytime peak. As the German PV market continues to grow reductions in wholesale peak energy prices will become more common resulting in lowered retail electricity prices for consumers.

As mentioned, Germany's PV tariff is uncapped, and there are no limits to the total ratepayer costs. While this has been a key feature that allowed significant, stable market growth, the policy has had an impact on German ratepayers. A recent analysis by the BMU reported that the average German ratepayer pays €12 per month to support the German feed-in tariff policy. The current per kWh surcharge is € 0.035 ($0.047) per kWh and may be rising to as much as € 0.06 ($0.08) per kWh in 2012 (Reuters Deutschland, 2011). The German environmental ministry (BMU) periodically updates a cost-benefit analysis of the German renewable energy policies. The most recent analysis found that the benefits of the programs were generally in line with or exceeded the costs, particularly when environmental impacts were considered (van Mark & Nick-Leptin, 2010). The study also found significant benefits from reduced wholesale market electricity prices as a result of renewable energy generation during periods of peak demand (Federal Ministry of Environment, Nature Conservation and Nuclear Safety, 2009).[203]

Table 108 below defines some of the strengths and limitations of the German solar feed-in tariff.

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[203] The phenomenon, known as the "merit-order" effect has been cited as one of the main contributors to the cost effectiveness of the German feed-in tariff. In 2006 alone, it was estimated that reductions in wholesale energy prices resulted in €5 billion in energy costs savings from German consumer.

Table 108. Strengths and Limitations of the Germany's Feed-in Tariff

Policy Strengths
Driving rapid market expansion
Supporting world's largest PV market
Policy structure minimizes risks for developers and investors
Differentiated rates and standard offers support growth among all system sizes
Majority of new capacity is from smaller-scale systems
Program participation not tied to building loads
Policy Weaknesses
Lack of cap and large market response mean high comparative policy costs
Annual automatic adjustment mechanism has not kept pace with market

Case Study: Spain

Like Germany, the primary PV incentive in Spain is structured as a feed-in tariff. Nevertheless, unlike the German PV market, Spain's solar incentive policy has produced a less stable market, with uneven growth in recent years. At the end of 2010, Spain had a total installed capacity of 3.8 GW. In 2010 the market added 369 MW, after having added just 17 MW in 2009 (EPIA, 2011). According to industry estimates, PV provides roughly 4% of Spain's electricity consumption during summer months and 1% during the winter season. The Spanish PV market is expected to more than double over the next decade as the National Renewable Energy Plan calls for 8.7 GW of cumulative capacity by 2020 (MITYC and IDEA, 2010)

Spain's PV feed-in tariff policy has undergone significant changes in recent years. In 2008 an inadequately designed limit on the volume of deployed PV installations created an over-heated market that quickly and significantly exceeded the program's expected capacity. The Spanish government had set a target of installing 400 MW of PV by 2010, however this target was exceeded by 2007 and an additional 2.7 GW was installed in the country in 2008 – before the legislature officially revised the feed-in tariff rates. More recently, the nation's financial challenges have led to a retroactive decrease in tariff payments for existing installations and a reduction in payments for future PV systems. This has led to several lawsuits from PV system developers (Castano, 2011).

The inconsistent Spanish incentive programs have led to a boom-bust cycle in the Spanish solar industry. Industry participants report significant job losses in the sector since the 2008 market peak (SolarServe, 2010). It is important to note that the Spanish economy is experiencing significant distress and is currently implementing nationwide austerity measures in an effort to improve its government balance sheet (Reuters, 2010). The cuts to solar incentive programs have been a part of these austerity efforts (GlobalEnergy Magazine, 2010).

Policy Type and Goals

Spanish government PV goals have changed over the course of the past decade as global market conditions have changed and incentive programs have led to rapid, if uneven, capacity growth. The 2005-2010 long-term renewable energy plan targeted 400 MW installed capacity by 2010 (IDAE, 2005). This target was exceeded in 2007 during the boom years of the Spanish PV market. More recently the government has established a 2020 projection of installing 8,367 MW. Given Spain's base of installed capacity, this projection would result in 430 MW installed per year from 2011 to 2020.

Feed-in Tariff Policy Structure

Like Germany, Spain uses a cost-of-generation-based feed-in tariff with a standard offer contract and guaranteed interconnection. The basic features of the feed-in tariff were first implemented in 1997 (BOE, 1997); however, the PV market did not grow significantly until the program was expanded in 2004. Spain uses periodic revisions as well as market size triggers for policy amendments. Under current Spanish law, tariff payments have up to a 28-year term (BOE, 2010). Table 109 provides key policy features of the Spanish feed-in tariff.

Table 109. Spanish Feed-in-Tariff Policy Features

POLICY FRAMEWORK CATEGORY	SPANISH FEED-IN TARIFF PROGRAM FEATURES
Incentive type	Cash payment
Basis for incentives	Performance based
Timing of incentives	Paid over time based on a contract up to 28 years
Degree of revenue certainty	Revenue certainty is established by a long-term contract of 28 years. (Although recent retroactive payment changes have changed project economics and rattled investor confidence)
Timing of revenue certainty	Payment rates are known pre-construction
Commodities transferred /purchased	Electricity
Setting the incentive level	Cost-based tariff level, adjusted quarterly based on capacity additions

As with the German feed-in tariff, the Spanish solar feed-in tariff is divided into multiple system classes. The current Spanish policy has three system classifications: rooftop smaller than 20kW, rooftop larger than 20kW and all ground mounts. Table 110 shows 2010 and 2011 tariff rates from the Spanish PV incentive program.

Table 110. Spanish PV Feed-in Tariff Rates 2010 and 2011

	2010 TARIFF RATE €/kWh ($/kWh)	Q1 2011 TARIFF RATE €/kWh ($/kWh)
Ground Mount	0.32 (0.43)	0.176 (0.235)
Rooftop > 20kW	0.31 (0.41)	0.233 (0.312)
Rooftop <= 20 kW	0.34 (0.45)	0.323 (0.432)

Evolution of the Spanish Market and PV Policies

The Spanish PV market has fluctuated significantly over the last five years. The market grew relatively moderately until 2006 with a total installed capacity of 146 MW at the end of that year. During 2007 and 2008 the market grew exponentially, with annual growth rates of nearly 500%. In 2008 alone, approximately 2.7 GW of new PV capacity was added to the grid making Spain the second largest PV market in the world at the time. After this unexpected market growth, the government imposed a new capacity cap and reduced tariff rates, resulting in significantly lower levels of installed capacity in 2009 and 2010. During 2009, only 17 MW of PV were installed while the market recovered in 2010 with 369 MW of additional capacity—below the federally imposed 502 MW cap. Figure 60 shows upper and lower bounds for Spanish PV tariff rates from 2003 to 2010 as well as cumulative installed capacity.

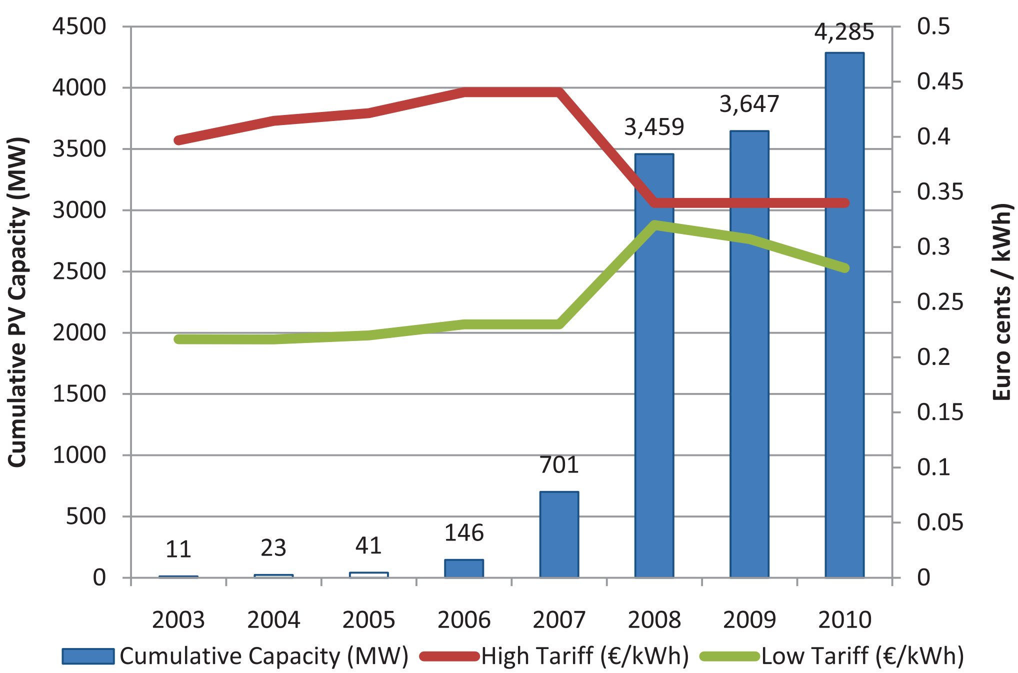

Figure 60. PV Market Growth and Feed-in Tariff Adjustments in Spain (2003-Present)

Tariff differentiation in Spain has evolved over time. From 2004 to 2007, the Spanish government implemented a two tier system in which a project below 100 kW received a different rate from projects larger than 100 kW. This was modified to a three-tier system in 2007, where rates were set for projects that were 0 – 100 kW in size, 100 kW – 10 MW in size, and 10 MW to 50 MW in size. The tiered system quickly became problematic, as the legislation did not properly define the parameters of a single "project". Developers took advantage of this ambiguous legislation to split large projects into many smaller projects of 100 kW in size, securing higher tariff rates.

Under laws implemented in 2007, a rate adjustment was triggered when 85% of the program's 2010 target capacity was reached. In theory, this provided flexibility and control to the Spanish government, as they could readjust rates based on the market size and available funds. This structure was design based on experience from the wind energy market, where project planning can take several years and project developers need long incentive certainty horizons to effectively develop projects. Still, legislators failed to stipulate that the 85% rule only applied to wind projects. As a result, PV developers rushed to get projects built within the 2007-2008 tariff level knowing that a reduction would take place in the autumn of 2008 – one year after the 85% target of the 400 MW for 2010 had been reached. This overheated the market led the Spanish government to significantly revise the program in 2008 by enforcing a capacity cap, dramatically cooling the Spanish PV market. This new legislation included a yearly hard cap along with quarterly price "calls" to determine the tariff level for specific blocks of PV capacity targets.

Under this new price setting policy, the Spanish government established a series of triggers to dynamically adjust rates based on market demand. The tariff degression schedule is modified based on how much capacity has been added to the market. If the quarterly shares are undersubscribed, meaning they hit less than 50% of their target amount, rates increase by 2.6%. If between 50 – 75% of the quarterly target is met, rates remain stable. If between 75 – 100% of the target rate is met, rates are reduced by an amount proportional to the capacity added to the market up to 2.6%. While in theory this system keeps rates in line with market costs, in reality the complexity has caused uncertainty for developers and investors (Kreycik, Couture, & Cory, 2011).

Costs and Cost Control

In Spain the national legislature controls the costs of renewable electricity support by instituting capacity caps. Nevertheless, in the period 2007 to 2008 these caps were ineffective in the PV market as the one-year interim period did not allow Spanish legislators to intervene. As of 2010, solar subsidies totaled roughly had €4 billion ($5.36 billion) (Comisión Nacional de Energía , 2010). Bloomberg New Energy Finance estimates program costs for the Spanish solar feed-in tariff to be €783 million ($1.05 billion) per year. The Spanish legislature is also tasked with adjusting the tariff level to reflect generation costs and to this end the most recent Spanish feed-in tariff rates are similar to those in Germany. Still, there have been frequent adjustments of the tariff levels in 2007, 2008 and again in 2011. Currently the electricity system is running under a budget deficit and therefore cost control has taken on additional significance to legislators.

In Spain's energy market, electricity rates for some ratepayer classes are regulated in a way that electricity prices can only increase by a certain capped amount each year. This unique market mechanism has caused the budget deficit in the national electricity budget, in part due to the increased costs of renewable energy supply on the grid and in particular from capacity additions from 2008 (Couture, Cory, Kreycik, & Williams, 2010). This deficit was historically financed by capital markets, however, global financial conditions have made financing this debt difficult and in 2009, Spain created a special securitization fund to finance this €10 billion debt. The current Spanish plan is to pay down this remaining debt by incrementally increasing electricity costs. Special provisions have been made to assist low income ratepayers.

Lessons Learned

In 2008, Spain was the world's second largest PV market; however, the frequent policy changes and tariff adjustments, along with the policy loophole in 2008, have created a template for how not to implement a PV feed-in tariff. One problem was that tariff levels in the 2007 legislation were too high. The most significant problem, however, was the decision to guarantee this high tariff payment for twelve months after 85% of the interim target was achieved. In short, the Spanish market exploded because of a high tariff payment combined with a poorly-designed capacity cap. In addition, frequent policy changes have eroded investor confidence and drastic cuts and retroactive payment reductions have resulted in thousands of lost jobs in the Spanish PV industry as well as industry lawsuits against the government (Castano, 2011). Additional complicating factors were the unique regulations within the Spanish electricity market. Due to restrictions on distribution company's abilities to recover costs from ratepayers, distribution companies are forced to finance their annual operating deficits. This regulatory requirement proved especially problematic as the share of tariff-eligible PV systems increased dramatically in 2008 and the global credit crunch began to take effect (Couture, 2011).

The weakness of the Spanish feed-in tariff has been its boom-and-bust cycle and the overrun on policy cost caps. Under current rules, the program has been more stable, controlling both costs and market growth with a system of quarterly capacity caps and tariff price degressions. In addition, prior tariff rate triggers did not effectively follow PV price reduction trends and led to over building of the market. Additionally, the error made in the 2007 tariff adjustment caused long-term stress on the Spanish energy sector. Over the past three years, the government has been actively trying to re-negotiate tariff rates for systems installed in 2008. This renegotiation has been justified based on the windfall returns developers have made due to the poorly designed tariff. Still, these prolonged negotiations have resulted in market uncertainty with Spanish solar companies restructuring or going out of business (Photon International, 2011). The dynamics of the

Spanish PV market have also affected global PV module prices, with some commentators attributing the drop in global module prices in 2009 to the cooling off of the Spanish market.

Table 111 below defines several of the strengths and limitations of the Spanish solar feed-in tariff policy.

Table 111. Strengths and Limitations of the Spanish PV Feed-in Tariff

POLICY STRENGTHS
Created the Spanish PV industry
Long-term FiT contract provided financing and investment opportunities during the years prior to 2008
Created a large market for and experience with ground-mounted PV systems
POLICY WEAKNESSES
Boom and bust cycle due to FiT rate fluctuations
Overrun on policy and program caps
Tariff rate adjustment triggers did not effectively follow PV price reduction trends
Design flaws that focused on wind power projects did not translate to PV projects
Retroactive payment and contract adjustments

Case Study: New Jersey

With nearly 400 megawatts of installed PV capacity, New Jersey is the second-largest solar market in the U.S. behind California. In 2010, New Jersey installed more than 132 MW (N.J. BPU, 2011d) and analysts expect more than 241 MW of capacity will be added in 2011(Photon, 2011a). In recent years, the New Jersey PV market has been driven by a solar requirement in the state's renewable portfolio standard. In addition to the state's RPS solar requirements, a number of supporting policies have been created through regulatory orders that have reduced market volatility and provided revenue certainty to PV project developers.

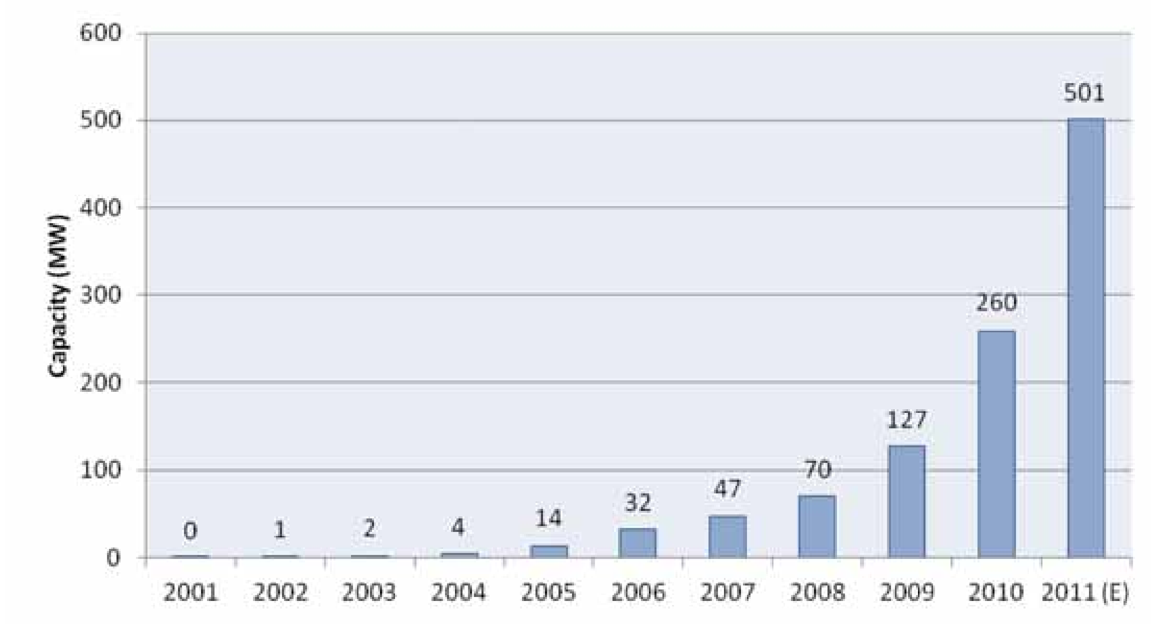

Figure 61. New Jersey Cumulative PV Capacity 2001-2011

Since transitioning to an SREC-only incentive program, the New Jersey solar market has seen high prices in the state-wide SREC market. Still, in recent months, market participants have grown concerned that this fast growing market may have overheated. After trading near their maximum value for the first three years of the program, SRECs for the 2012 compliance year are now trading near $225 per MWh, a significant decrease from previous compliance years where SREC frequently traded over $600 per MWh. A number of analysts have observed that the state's existing installed capacity at the beginning of the 2012 compliance year (July 2011) was sufficient to meet the compliance requirements for the entire year without any incremental capacity additions over the next twelve months (SRECTrade, 2011). This has resulted in a sharp decline in SREC prices. In reaction to this price decline, and the subsequent concern from PV system owners and project developers, several New Jersey legislators have introduced a bill to increase the state's RPS obligation in order to increase SREC requirements on LSEs and SREC market prices (Flett Exchange, 2011).

The following section discusses the structure and regulatory history of the New Jersey PV incentive program and also provides an overview of the market as it has grown over the past decade.

Policy Type and Goals

New Jersey's LSEs have had a solar obligation under the state's SREC program since 2005. During the early part of the last decade, the New Jersey Board of Public Utilities, through the Clean Energy Program, operated solar rebate programs funded through a state systems benefit charge (SBC) that supported a significant share of the state solar market. During 2007, the Board decided that the rebate-supported market could not grow sufficiently to meet the LSE's solar obligations under the state RPS, so stakeholder process was initiated that resulted in recommendations to transition the New Jersey solar market away from rebate payments and towards an renewable energy quantity obligation program (N.J. BPU, 2010). In late 2007, the BPU revised the existing RPS regulations to increase the solar alternative compliance payments to a level that could support solar generation without rebates. PV rebate programs were phased out, with the last solar rebates for smaller systems being distributed in 2010.

New Jersey's current solar incentive program is structured as a solar-specific requirement that makes up part of the state's renewable portfolio standard. In order to meet the solar requirements of the state's RPS law, New Jersey's load serving entities (both third party electricity suppliers and basic service suppliers) must acquire Solar Renewable Energy Credits (SREC) in quantities sufficient to meet their solar RPS obligations. Table 112 shows the annual total SREC obligation that the state's LSEs must procure from solar generation under current regulations. Prior to the enactment of A.B. 3520, the SREC program obligation was expressed as a percentage of total LSE load. The obligation was changed from a percentage to a fixed energy production requirement for all compliance years after 2010.

Table 112. New Jersey SREC Program Obligations.

YEAR	PV CARVE-OUT	YEAR	PV CARVE-OUT
2005	0.01%	**2016**	1,150 GWh
2006	0.02%	**2017**	1,.357 GWh
2007	0.04%	**2018**	1,591 GWh
2008	0.08%	**2019**	1,858 GWh
2009	0.16%	**2020**	2,164 GWh
2010	0.22%	**2021**	2,518 GWh
2011	306 GWh	**2022**	2,928 GWh
2012	442 GWh	**2023**	3,433 GWh
2013	596 GWh	**2024**	3,989 GWh
2014	772 GWh	**2025**	4,610 GWh
2015	965 GWh	**2026**	5,316 GWh

SREC Market Structure

Table 113 below describes the New Jersey solar RPS carve-out using the framework defined earlier in Section 9.4.3 of this report.

Table 113. New Jersey SREC Program Policy Features

Policy Framework Category	New Jersey SREC Program Features
Incentive type	Cash (tradable Solar Renewable Energy Certificates)
Basis for incentives	Performance based; SRECs are created in MWh denominations
Timing of incentives	SRECs are generated as produced by a PV system and monetized during or shortly after the close of a compliance year (Note: SREC have a two-year shelf life)[204]; Generators are eligible to produce SRECs for 15 years
Degree of revenue certainty	Revenue for RECs that are traded in spot or short-term markets is highly uncertain. There are mechanisms available, however, to securitize REC revenue streams (e.g. price floors or utility financing programs).
Timing of revenue certainty	There is no certainty for traded RECs. Timing of security for utility financing programs depends on the program. For the auction programs, for example, revenue certainty is not established until after the auction.
Commodities transferred /purchased	SRECs under New Jersey regulation, are decoupled from electricity
Setting the incentive level	• Market-based for tradable SRECs • Competitive process for SREC auctions • Administrative determination for price floor (e.g., utility loan program floor value)

Unlike neighboring Pennsylvania, the New Jersey SREC market is limited to PV generators located within the state borders. Under current regulations, system sizes are not capped; however, net-metered systems are limited to only serve the annual on-site energy demand. Projects currently qualifying under the New Jersey SREC program are eligible to produce SRECs over a 15-year period.

The New Jersey SREC market operates on an Energy Year cycle that runs from June to May. Obligated entities include all load serving entities, from Third Party Suppliers (TPSs) to electric distribution companies that offer Basic Generation Services (BGSs). Electricity under contract with BGS suppliers prior to the initiation of the revised SREC program in 2009 are exempt from new SREC obligations, however state law requires that the state-wide solar target must be met. In effect, SREC obligations that would have been met by compliance entities with exempted loads are dispersed to non-exempt loads in order to ensure the state-wide obligation target is met (Flett Exchange, 2011) .

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204 In New Jersey, SRECs can be sold in multiple compliance years, not just the compliance year in which they were generated.

Utility Financing Programs

In addition to requiring load serving entities to meet solar-specific RPS obligations, the four New Jersey electric distribution companies are required to support the state SREC program with long-term financing programs. In 2009 the New Jersey BPU ordered each of the state's Electric distribution companies (EDCs) to develop financing programs that reduce solar developer risk by offering long-term price stability to project developers (N.J. BPU, 2010). The BPU views the New Jersey SREC market as segmented into two tiers, the "structured market" where SRECs are contracted for 10-15 years through the utility financing programs, and the "open market" where SRECs have less price certainty (N.J. BPU, 2011d). The state regulator is currently exploring the effectiveness of these initiatives as it reviews whether they should be renewed or revised at the end of the 2012 compliance year. The following sections discuss the details of these utility financing initiatives.

PSE&G Loan Program. Public Service Electric and Gas (PSE&G) is the largest investor owned utility in New Jersey, serving nearly three quarters of the state's customers(PSE&G, 2011a). In April 2008, the BPU approved PSE&G's solar loan initiative and subsequently approved an updated version of the same program in November 2009 that met the regulatory requirements of the utility financing program regulations (N.J. BPU, 2009).

The Solar Loan Program provides PSE&G customers financing valued at between 40-60% of a PV system cost. System owners have the option of repaying PSE&G through transfer of SRECs or through cash payments. The program establishes an SREC *price floor* by guaranteeing the repayment value of SRECs. Table 115 shows the current price floor for SRECs paid to PSE&G as loan repayments under the existing program. If a system owner chooses to repay by transferring SRECs, PSE&G will auction off the transferred SRECs into the open market. If the value at auction is above the transfer value, the system owner will receive a further credit above the guaranteed minimum SREC value against their loan.

Table 114. Price Floor for the PSE&G Loan Program ($/MWh)

PROJECT CLASS	DEC 2009- JUN 2010	JULY 2010- DEC 2010	JAN 2011- JUN 2011	JULY 2011- DEC 2011
Residential	$450	$435	$420	$400
Small Non-residential (up to 150kW)	$410	$395	$380	$360
Large Non-residential (>150-500kW)	$380	$365	$350	$330

To date, the program has supported 24 MW of PV and has a total expected capacity of 51 MW (PSE&G, 2011b). The initiative is scheduled to expire by December 2011 after eight quarters of operations. In addition to its solar lending initiatives, PSE&G is operating a direct solar ownership program. The

Solar4All program is a BPU approved initiative for PSE&G to develop 80 MW of solar capacity. The program is divided between 40 MW of utility-pole mounted PV and 40 MW of traditional ground and roof-mounted PV systems.

Other EDC Financing Programs. The state's three other EDCs (Atlantic City Electric, Rockland Electric Company and Jersey Central Power and Light) operate a joint solicitation program in order to meet their requirement to provide a long-term financing program. Unlike the PSE&G program the joint program is not structured as a loan, but provides a long-term, fixed price SREC contract.

Under the approved programs, each of the three utilities must contract for SRECs from a specified amount of PV capacity over a three year period (EYs 2010-2012). The program is designed to support 64 MW of capacity with ACE accounting for 19MW, JCP&L 42 MW and RECO 3.8 MW. The first program auction was conducted in August 2009. To date, seven solicitations have been completed, with 341 PV systems receiving contracts with a total capacity of more than 58 MW (NJEDC, 2011). Depending on auction results, the program may be fully subscribed after the next solicitation.

Table 115. Average Prices in Dollars per MWh for 10-Year Contracts under the ACE, REC and JCP&L PV Contracting Programs (NERA Economic Consulting, 2009-2011)

<table>
<tr><th>SOLICITATION DATE</th><th colspan="3">AVERAGE PRICE ($/MWH)</th><th>NOTES ON SIZE CLASSES</th></tr>
<tr><td>8/25/2009</td><td colspan="3">$410</td><td>< 500kW</td></tr>
<tr><td>12/11/2009</td><td colspan="3">$405</td><td>< 500kW</td></tr>
<tr><td>3/5/2010</td><td colspan="3">$424</td><td>< 500kW</td></tr>
<tr><td>6/11/2010</td><td colspan="3">$466</td><td>< 500kW</td></tr>
<tr><td>10/14/10</td><td colspan="2">$479</td><td>$450</td><td><50kW and 50kW-500kW</td></tr>
<tr><td>2/17/2011</td><td colspan="2">$448</td><td>$414</td><td><50kW and 50kW-500kW</td></tr>
<tr><td>6/7/2011</td><td>$379</td><td>$303</td><td>$280</td><td><50kW, 50kW-500kW, >500 kW– 2MW</td></tr>
<tr><td>9/2/2011</td><td>$233</td><td>$222</td><td>$215</td><td><50kW, 50-500, >500 – 2MW</td></tr>
</table>

Cost Control Mechanism

The primary cost control mechanism in the New Jersey SREC program is the solar alternative compliance payment (SACP). If insufficient SRECs are generated in a given year to meet the regulatory requirements of the state's RPS, LSEs have the ability to pay the SACP in lieu of purchasing and retiring SRECs. The SACP effectively places an upper bound on the cost of the solar incentive program. This cost control mechanism has been widely used in both solar RPS carve outs and RPS main tiers. Given the cost premium associated with PV, SACP levels need to be significantly higher than main tier ACP levels. The BPU is currently engaged in a rulemaking process to set the SACP level through 2026(N.J. BPU, 2011a). In setting SACP levels, the Board had the explicit goal of setting a cost high enough to incent obligated entities to sign long-term contracts with SREC suppliers and also at levels high enough to allow for PV system project development.[205]

Table 116. Solar Alternative Compliance Payment Schedule for New Jersey SREC Program 2009-2016 and Average SREC Prices 2009-2011 .(N.J. Administrative Code, 2010; N.J. BPU, 2011c)

REPORTING YEAR	SACP	AVERAGE REC PRICE	AVERAGE PRICE/ SACP
JUNE 1, 2008 - MAY 31, 2009	$711	$544.85	0.77
JUNE 1, 2009 - MAY 31, 2010	$693	$615.50	0.89
JUNE 1, 2010 - MAY 31, 2011	$675	$601.43	0.89
JUNE 1, 2011 - MAY 31, 2012	$658		
JUNE 1, 2012 - MAY 31, 2013	$641		
JUNE 1, 2013 - MAY 31, 2014	$625		
JUNE 1, 2014 - MAY 31, 2015	$609		
JUNE 1, 2015 - MAY 31, 2016	$594		

In the 2010 compliance year, New Jersey's obligated entities had a total SREC obligation of 171,094 MWh. More than 70% of this obligation was met through purchase and retirement of SRECs and roughly 30% of the obligation was met through SACP payments. The BPU estimates the entire 2010 compliance costs for the program was slightly over $108 million (N.J. BPU, 2010).

Under previous rules, the New Jersey SREC program had a programmatic cost limit that capped compliance costs at 2% of total retail electric prices. This provision was revoked as part of the Solar Advancement Act of 2010 (DSIRE, 2011b). Industry analysts have reported that the cap was removed as it created a challenging financing environment for project developers as project revenues could be significantly affected in the event the cost cap was reached(SREC Trade, 2011a).

Lessons Learned

The New Jersey solar program has incented the development of nearly 400 MW of PV in short period of time and the BPU expects nearly 500 MW to be installed by the end of 2011. One important lesson from the New Jersey market is that high prices in the early years of an SREC market can drive aggressive development. This early growth has, however, led to an unstable market. It is estimated that the New Jersey market could be oversupplied for at least the next few years, with little new market growth needed to meet

[205] "The SACP levels were set approximately $100 above the SREC values estimated to be necessary to reach the RPS goals with diverse market participation. The SACP levels were also designed to serve as a motivation for load serving entities to procure SRECs in lieu of seeking compliance via payment of SACPs." in http://www.njcleanenergy.com/files/file/Renewable_Programs/9-21-11-8D.pdf pg 2

current RPS obligations. This market overshoot has led to a ramp-down in system installations. Market based quantity obligation programs, such as New Jersey's, have the risk of cycling between over and undersupply, leading to market boom-bust cycles and challenging environment for installers and project developers. Sharp decline in SREC prices precipitated by an over-supplied regulatory market are not unique to New Jersey. A number of other state solar markets have undergone the same cycle of SREC under-supply followed by a price crash as the markets becomes overbuilt(Photon Consulting, 2011). The Pennsylvania SREC market recently saw a crash in credit prices after enough capacity was installed to meet compliance obligations for several years.

The New Jersey Investor Owned Utility contracting and financing programs have been a unique innovation to an SREC market and have been successful in supporting a limited portion of the market. These programs have created long-term SREC price security for the limited segment of the market that receives EDC support. Still, the EDC financing programs are set to expire in the near term, compounding the effect of the SREC oversupply and likely precipitating further contraction in the New Jersey PV market. One important lesson learned from the New Jersey case is that utility financing programs can be an effective tool at taking price risk out of an SREC market, but that those programs must have long time horizons to ensure continued effectiveness.

New Jersey regulations allow EDCs to develop and own their own PV generation assets. This has led to the development of some of the largest megawatt scale PV systems in the state. Direct utility owned systems account for the majority of the wholesale PV generator in New Jersey. An important lesson from the New Jersey market is that utility PV ownership can be a leading driver of system size diversity.

Table 117. Strengths and Limitations of the New Jersey Solar RPS Carve Out

STRENGTHS
Market-based solution that adjusts to declining PV installation prices
SREC price support through long-term contracting under utility programs
Long time horizon for market solar requirements
Adequate SACP to support solar projects
Direct ownership by utilities has spurred market of large-scale installations
LIMITATIONS
SREC price support through utility programs is limited
Near-term oversupply has led to swings in SREC prices and uncertainty in the market

APPENDIX 3 – SELECTED POLICY OPTIONS ANALYSIS

A3.1. Administrative Cost Considerations

Administrative costs are costs for the government or utility to administer an incentive or regulatory program. This study considered the comparative administrative costs of different policies as part of the effort to select a subset of policies for modeling. Administrative costs were determined to not be a significant driver of overall ratepayer costs, so standard administrative cost assumptions were aligned for each of the policies chosen for modeling. This Appendix summarizes administrative cost considerations that were taken into account during the research phase of this project.

Administrative Cost Drivers

The administrative costs of renewable energy programs include the following[206]:

- Program administration costs – creating and processing applications for incentives, running competitive procurements, evaluating responses, marketing the program to prospective participants, and tracking and reporting program progress. These costs would be incurred either by NYSERDA or the utilities, depending on how program management responsibilities are allocated
- Legal costs – the costs associated with developing and managing legal contracts with developers and with dealing with any other legal issues
- Monitoring and verification costs – the hardware, software, consultant fees , and staff time involved with tracking program progress, expenditures, and performance
- REC tracking system costs – most regions in the country use an online REC tracking system to monitor both in-state and trans-boundary REC transfers (FERC, 2010)
- Regulatory oversight costs – the costs to regulators of monitoring, evaluating, and approving changes to policies, developing and promulgating new regulations, and maintaining relationship with program administrator.

New York Administrative Cost Baseline

New York already has established administrative infrastructure and capacity in place for its clean energy programs, as well as an in-state clean energy industry familiar with navigating the process to build PV projects. For the discussion of administrative costs, the NYSERDA-administered procurements were used as a proxy, although both NYPA and LIPA administer unique programs:

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206 Adapted from Summit Blue and RMI (2007)

- The costs of the MT procurement included the upfront costs of developing and maintaining the bid processing system (including bid technical review), and the legal costs associated with contract development. The MT also incurs annual costs, including: the staff and consulting time to organize and administer the periodic competitive procurements, the cost of contract negotiations and adjustments, legal and administrative costs over time to administer contracts, the verification of project economic benefit claims, and the costs of program monitoring
- The costs associated with the CST are the costs of setting up the rebate intake, review, and processing system, including software and consulting fees. On an annual basis, there are costs associated with processing rebate applications, including inspection and verification
- Although NYSERDA manages the state programs, it is distribution utilities that are responsible for administrating the RPS fund collection through a surcharge per kilowatt-hour of electricity they sell applied on ratepayer bills
- New York State is also actively developing a REC tracking system for the state (Saintcross, 2011; Windgate, Pepper, Wiser, DeWitt, Adels, & Hamrin, 2003). For the purposes of this study, it was assumed that the costs of developing a REC tracking system are already included in the baseline and that new polices (e.g. those requiring tradable RECs) would not incur the incremental cost of a tracking system.

Lessons from Other Jurisdictions

In order to evaluate whether any of the proposed policies will have a significant impact on administrative costs, a scan of administrative cost data and studies of other jurisdictions was conducted. There have been several recent publications that discuss the comparative administrative costs of different types of policy mechanisms at a high level. During the recent Reverse Auction Mechanism proceedings in California, for example, some intervening parties argued that standard offer PBIs have far higher administrative costs than auctions (Nimmons, 2009). Other papers have argued that standard offer PBIs actually have comparatively low administrative costs (Haase, Podewils, & Hirsch, 2011).[207] There have been few empirical efforts to date in the US, however, to compare administrative costs according to policy type.[208] A recent effort to quantitatively estimate administrative costs was undertaken in support of New Jersey's solar energy market transition proceedings. This study (which did examine similar types of policies to those explored in this study) found that there were differences in costs between policies, but that, "the effects on overall ratepayer impacts would be negligible… even if the estimated administrative cost estimates were to increase by a factor of two (Summit Blue & RMI, 2007)."

[207] Evidence from Germany suggests that the program administrative costs are less that 1% of total program costs (Breitschopf, Sesfuss, Klobasa, Steinbach, & Ragwitz, 2011).

[208] The State of Delaware gathered administrative cost data from several different states during its Sustainable Energy Utility design process, but the programs reviewed do not cover the full range considered in this study (Sustainable Energy Utility Task Force, 2007).

Administrative Cost Considerations for Alternative Policies

It is unlikely that the introduction the policy types considered under the “pure” policies (Section 10.2.2) will create significant new administrative burdens on the state in New York, given the administrative infrastructure that is already in place. Standard offer PBIs would require new regulatory proceedings to design the policy and set rates, but it is unclear how much incremental work would be required above the effort currently required to set rebate levels for the CST.[209] The increased costs of new policy types might also be offset by savings from other current policies. A standard offer PBI, for example, would avoid the costs of administering competitive procurements under the MT.[210]

Although the type of policy may not significantly impact overall policy cost impact, there are several administrative cost considerations that deserve policymaker attention:

- The cost of scale. The scaling-up of policies will add significant new costs as more staff are added to deal with a greater magnitude of systems. A key question is how easily the policy type can absorb scaled-up administrative requirements. A significant expansion of public sector staff to administer a government-run central procurement may not be politically acceptable, for example. An expansion of LSE staff distributed across several service territories, however, could be more feasible
- Transfer of costs to other entities. Several of the models contemplate that large portions of program administration and management will be largely transferred to utilities (e.g. standard offer PBIs). These scenarios do not leverage the state’s existing infrastructure and instead require the utility to create new systems and build internal management capacity. At the same time, they do permit the state to reduce its program management resources for the roles that have been outsourced to the LSEs
- Funding mechanisms. Administrative costs can be recovered through state budgets or recovered from the ratepayers using a variety of different channels. One example is the Massachusetts solar market’s price floor auction mechanism, which includes a $15/MWh surcharge on developers for administrative costs. The surcharge supports the management of the program. Table 118 below summarizes some of the key administrative cost considerations associated with the pure policies considered as part of this study.

209 A key factor would be how differentiated the standard PBI rate was (i.e. how many different rates need to be set) compared to the number of existing rebate levels.

210 The “start-up” phase of the FIT can involve significant regulatory work, including designing a rate setting model, identifying the types of inputs required, identifying sources of data, and then reviewing outputs. Subsequent rate setting proceedings, however, are a process of adjustment rather than creating the process from scratch - many of the same models, data sources, and input assumptions can be reused.

Table 118. Incremental Administrative Cost Considerations for Pure Policies

1A. SOLAR QO WITH TRADABLE SRECS	1B – SOLAR QO WITH TRADABLE SRECS + PRICE FLOOR	2A - AUCTION FOR LT CONTRACTS	2B - CENTRAL PROCURE-MENT	3 - STANDARD OFFER PBI	4 – STANDARD OFFER REBATE
Avoids need for competitive bidding Transfers program management to LSEs	Avoids need for competitive bidding Transfers program management to LSEs Potentially high cost of capitalizing floor price mechanism	If utility managed, requires the utility to create new systems and build internal management capacity	Costs of scale-up to handle large volume of small projects	Potential additional costs from rate setting Avoids competitive procurement Shifts most program administration costs to LSEs	Avoids competitive procurement Avoids need for ongoing relationship with generator

APPENDIX 4 – LCOE FORECAST BY PROJECT SIZE & LOCATION, 2011-2025

Real LCOE in 2011$ (first 3 tables) and Nominal LCOE (Last 3 Tables)

Table 119. Base Case LCOE: (Including 5-year Phase-Down of 15% ITC Value), 2011 ¢/kWh

Location	Size	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Upstate	Residential	48.75	45.60	42.48	39.67	37.13	34.82	34.46	33.92	33.39	32.75	32.07	30.32	28.80	27.50	26.34
	Small C&I	45.75	42.84	40.06	37.48	35.16	33.17	32.74	32.24	31.65	31.04	30.56	29.01	27.67	26.56	25.65
	Large C&I	42.45	39.78	37.25	35.00	32.82	30.96	30.49	30.02	29.39	28.73	28.22	26.88	25.67	24.68	23.80
	MW-Scale	34.75	32.98	31.25	29.67	28.23	26.91	26.78	26.56	26.34	26.00	25.96	25.00	24.07	23.34	22.65
Capital	Residential	47.05	43.92	41.03	38.33	35.82	33.63	33.29	32.77	32.26	31.55	30.98	29.25	27.83	26.56	25.41
	Small C&I	44.35	41.56	38.80	36.33	34.13	32.15	31.75	31.26	30.78	30.10	29.64	28.19	26.87	25.78	24.88
	Large C&I	41.35	38.80	36.28	34.05	31.98	30.13	29.67	29.22	28.60	28.05	27.55	26.14	25.03	24.05	23.18
	MW-Scale	33.55	31.89	30.18	28.62	27.20	25.99	25.88	25.67	25.47	25.15	25.13	24.10	23.27	22.56	21.88
Downstate	Residential	44.75	41.85	39.09	36.52	34.13	32.06	31.66	31.17	30.69	30.10	29.48	27.86	26.47	25.23	24.26
	Small C&I	42.35	39.58	37.06	34.72	32.54	30.68	30.31	29.84	29.30	28.73	28.31	26.88	25.59	24.60	23.72
	Large C&I	39.45	37.02	34.64	32.52	30.48	28.75	28.32	27.89	27.30	26.68	26.22	25.00	23.83	22.95	22.11
	MW-Scale	32.05	30.42	28.82	27.38	25.99	24.79	24.71	24.52	24.25	23.95	23.96	23.03	22.23	21.54	20.88
NYC	Residential	53.95	50.33	46.94	43.76	40.88	38.32	37.89	37.29	36.70	35.91	35.25	33.26	31.52	30.01	28.80
	Small C&I	45.75	42.84	39.96	37.38	35.07	32.98	32.65	32.15	31.57	30.95	30.48	28.93	27.59	26.40	25.49
	Large C&I	42.65	39.88	37.35	35.00	32.82	30.96	30.49	29.93	29.39	28.73	28.22	26.80	25.59	24.60	23.72
	MW-Scale	34.65	32.88	31.05	29.48	27.95	26.73	26.51	26.38	26.08	25.75	25.80	24.75	23.83	23.11	22.42
Long Island	Residential	44.75	41.85	39.09	36.52	34.13	32.06	31.66	31.17	30.69	30.10	29.48	27.86	26.47	25.23	24.26
	Small C&I	42.35	39.58	37.06	34.72	32.54	30.68	30.31	29.84	29.30	28.73	28.31	26.88	25.59	24.60	23.72
	Large C&I	39.45	37.02	34.64	32.52	30.48	28.75	28.32	27.89	27.30	26.68	26.22	25.00	23.83	22.95	22.11
	MW-Scale	33.35	31.60	29.89	28.43	26.92	25.71	25.61	25.41	25.21	24.89	24.88	23.85	23.03	22.25	21.65

Table 120. Low Cost Future LCOE: (Current Federal Incentives Extended Indefinitely), 2011 ¢/kWh

Location	Size	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Upstate	Residential	39.95	35.94	32.31	29.00	27.95	25.35	22.99	20.97	19.11	17.46	16.01	14.69	14.38	14.16	13.96
	Small C&I	37.95	34.36	31.15	28.33	27.58	25.35	23.26	21.51	19.90	18.40	17.10	15.92	15.66	15.42	15.19
	Large C&I	35.15	31.99	29.02	26.52	25.89	23.87	22.00	20.35	18.85	17.55	16.35	15.26	14.94	14.71	14.42
	MW-Scale	28.55	26.08	23.88	21.86	21.77	20.19	18.74	17.43	16.33	15.24	14.34	13.46	13.26	13.06	12.88
Capital	Residential	38.55	34.75	31.15	28.05	26.92	24.43	22.18	20.26	18.42	16.86	15.43	14.20	13.90	13.69	13.42
	Small C&I	36.75	33.37	30.28	27.48	26.74	24.61	22.63	20.80	19.29	17.89	16.60	15.42	15.18	14.95	14.73
	Large C&I	34.25	31.11	28.34	25.76	25.24	23.23	21.45	19.82	18.42	17.12	15.93	14.85	14.54	14.32	14.11
	MW-Scale	27.55	25.19	23.01	21.19	21.02	19.46	18.11	16.89	15.72	14.73	13.84	13.05	12.86	12.59	12.42
Downstate	Residential	36.75	33.08	29.69	26.71	25.71	23.32	21.18	19.29	17.55	16.10	14.68	13.46	13.26	13.06	12.80
	Small C&I	35.05	31.80	28.82	26.24	25.52	23.41	21.54	19.82	18.33	17.04	15.85	14.69	14.46	14.24	14.03
	Large C&I	32.65	29.73	26.98	24.62	24.11	22.13	20.46	18.93	17.55	16.35	15.18	14.20	13.90	13.61	13.42
	MW-Scale	26.35	24.11	22.04	20.14	20.09	18.63	17.30	16.10	15.02	14.05	13.25	12.48	12.22	12.04	11.88
NYC	Residential	44.45	39.98	35.80	32.14	30.48	27.55	24.98	22.66	20.59	18.74	17.02	15.59	15.26	15.03	14.73
	Small C&I	37.95	34.46	31.25	28.33	27.39	25.16	23.08	21.24	19.64	18.15	16.85	15.67	15.42	15.10	14.88
	Large C&I	35.35	32.09	29.11	26.52	25.80	23.69	21.81	20.18	18.68	17.29	16.10	15.02	14.70	14.40	14.19
	MW-Scale	28.45	25.98	23.69	21.76	21.49	19.83	18.38	17.07	15.98	14.90	13.92	13.13	12.94	12.67	12.50
Long Island	Residential	36.75	33.08	29.69	26.71	25.71	23.32	21.18	19.29	17.55	16.10	14.68	13.46	13.26	13.06	12.80
	Small C&I	35.05	31.80	28.82	26.24	25.52	23.41	21.54	19.82	18.33	17.04	15.85	14.69	14.46	14.24	14.03
	Large C&I	32.65	29.73	26.98	24.62	24.11	22.13	20.46	18.93	17.55	16.35	15.18	14.20	13.90	13.61	13.42
	MW-Scale	27.35	24.99	22.82	20.91	20.74	19.18	17.84	16.54	15.46	14.47	13.59	12.81	12.54	12.36	12.19

Table 121. High Cost Future LCOE: (Current Federal Incentives Cease After 2016), 2011 ¢/kWh

Location	Size	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Upstate	Residential	55.75	53.49	51.20	49.00	46.96	44.94	58.31	55.74	53.25	50.94	48.54	46.27	44.17	42.18	40.26
	Small C&I	55.15	52.99	50.82	48.81	46.96	45.03	58.22	55.74	53.42	51.19	48.96	46.85	44.82	42.88	41.10
	Large C&I	48.35	46.49	44.71	42.91	41.25	39.70	49.73	47.76	45.76	43.93	42.02	40.22	38.49	36.92	35.41
	MW-Scale	38.95	37.51	36.09	34.72	33.48	32.25	39.88	38.36	36.88	35.39	33.91	32.53	31.20	29.94	28.80
Capital	Residential	53.85	51.61	49.36	47.29	45.28	43.38	56.32	53.79	51.42	49.14	46.87	44.72	42.65	40.69	38.87
	Small C&I	53.45	51.42	49.36	47.38	45.56	43.75	56.41	54.05	51.85	49.66	47.54	45.45	43.45	41.63	39.87
	Large C&I	47.15	45.30	43.55	41.86	40.22	38.69	48.46	46.52	44.63	42.74	40.93	39.24	37.53	35.98	34.49
	MW-Scale	37.65	36.23	34.83	33.57	32.36	31.14	38.53	37.03	35.57	34.20	32.74	31.38	30.16	28.92	27.80
Downstate	Residential	51.25	49.15	47.04	45.10	43.12	41.35	53.61	51.22	48.98	46.75	44.61	42.59	40.57	38.80	37.03
	Small C&I	50.95	49.05	47.04	45.19	43.41	41.72	53.79	51.57	49.42	47.35	45.28	43.33	41.45	39.67	38.03
	Large C&I	44.95	43.23	41.51	39.86	38.35	36.85	46.29	44.39	42.54	40.77	39.09	37.35	35.76	34.33	32.87
	MW-Scale	35.95	34.65	33.28	32.05	30.86	29.67	36.81	35.34	33.92	32.58	31.32	29.99	28.80	27.66	26.57
NYC	Residential	61.85	59.30	56.73	54.24	51.93	49.73	64.81	61.95	59.17	56.49	53.81	51.35	48.90	46.65	44.56
	Small C&I	55.25	53.09	50.91	48.91	46.96	45.13	58.31	55.92	53.60	51.28	49.04	46.93	44.82	42.88	41.10
	Large C&I	48.55	46.68	44.81	43.10	41.44	39.79	50.00	47.94	46.02	44.10	42.19	40.38	38.65	37.00	35.49
	MW-Scale	38.85	37.42	35.99	34.62	33.29	32.06	39.88	38.27	36.79	35.31	33.82	32.44	31.04	29.78	28.64
Long Island	Residential	51.25	49.15	47.04	45.10	43.12	41.35	53.61	51.22	48.98	46.75	44.61	42.59	40.57	38.80	37.03
	Small C&I	50.95	49.05	47.04	45.19	43.41	41.72	53.79	51.57	49.42	47.35	45.28	43.33	41.45	39.67	38.03
	Large C&I	44.95	43.23	41.51	39.86	38.35	36.85	46.29	44.39	42.54	40.77	39.09	37.35	35.76	34.33	32.87
	MW-Scale	37.35	36.04	34.64	33.29	32.07	30.87	38.26	36.76	35.31	33.94	32.49	31.14	29.92	28.68	27.57

Table 122. Base Case LCOE: (Including 5-year Phase-Down of 15% ITC Value), ¢/kWh Nominal

Location	Size	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Upstate	Residential	48.75	46.25	43.85	41.65	39.65	37.85	38.15	38.25	38.35	38.35	38.35	37.05	35.95	35.05	34.25
	Small C&I	45.75	43.45	41.35	39.35	37.55	36.05	36.25	36.35	36.35	36.35	36.55	35.45	34.55	33.85	33.35
	Large C&I	42.45	40.35	38.45	36.75	35.05	33.65	33.75	33.85	33.75	33.65	33.75	32.85	32.05	31.45	30.95
	MW-Scale	34.75	33.45	32.25	31.15	30.15	29.25	29.65	29.95	30.25	30.45	31.05	30.55	30.05	29.75	29.45
Capital	Residential	47.05	44.55	42.35	40.25	38.25	36.55	36.85	36.95	37.05	36.95	37.05	35.75	34.75	33.85	33.05
	Small C&I	44.35	42.15	40.05	38.15	36.45	34.95	35.15	35.25	35.35	35.25	35.45	34.45	33.55	32.85	32.35
	Large C&I	41.35	39.35	37.45	35.75	34.15	32.75	32.85	32.95	32.85	32.85	32.95	31.95	31.25	30.65	30.15
	MW-Scale	33.55	32.35	31.15	30.05	29.05	28.25	28.65	28.95	29.25	29.45	30.05	29.45	29.05	28.75	28.45
Downstate	Residential	44.75	42.45	40.35	38.35	36.45	34.85	35.05	35.15	35.25	35.25	35.25	34.05	33.05	32.15	31.55
	Small C&I	42.35	40.15	38.25	36.45	34.75	33.35	33.55	33.65	33.65	33.65	33.85	32.85	31.95	31.35	30.85
	Large C&I	39.45	37.55	35.75	34.15	32.55	31.25	31.35	31.45	31.35	31.25	31.35	30.55	29.75	29.25	28.75
	MW-Scale	32.05	30.85	29.75	28.75	27.75	26.95	27.35	27.65	27.85	28.05	28.65	28.15	27.75	27.45	27.15
NYC	Residential	53.95	51.05	48.45	45.95	43.65	41.65	41.95	42.05	42.15	42.05	42.15	40.65	39.35	38.25	37.45
	Small C&I	45.75	43.45	41.25	39.25	37.45	35.85	36.15	36.25	36.25	36.25	36.45	35.35	34.45	33.65	33.15
	Large C&I	42.65	40.45	38.55	36.75	35.05	33.65	33.75	33.75	33.75	33.65	33.75	32.75	31.95	31.35	30.85
	MW-Scale	34.65	33.35	32.05	30.95	29.85	29.05	29.35	29.75	29.95	30.15	30.85	30.25	29.75	29.45	29.15
Long Island	Residential	44.75	42.45	40.35	38.35	36.45	34.85	35.05	35.15	35.25	35.25	35.25	34.05	33.05	32.15	31.55
	Small C&I	42.35	40.15	38.25	36.45	34.75	33.35	33.55	33.65	33.65	33.65	33.85	32.85	31.95	31.35	30.85
	Large C&I	39.45	37.55	35.75	34.15	32.55	31.25	31.35	31.45	31.35	31.25	31.35	30.55	29.75	29.25	28.75
	MW-Scale	33.35	32.05	30.85	29.85	28.75	27.95	28.35	28.65	28.95	29.15	29.75	29.15	28.75	28.35	28.15

Table 123. Low Cost LCOE Future: (Current Federal Incentives Extended Indefinitely), ¢/kWh Nominal

Location	Size	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Upstate	Residential	39.95	36.45	33.35	30.45	29.85	27.55	25.45	23.65	21.95	20.45	19.15	17.95	17.95	18.05	18.15
	Small C&I	37.95	34.85	32.15	29.75	29.45	27.55	25.75	24.25	22.85	21.55	20.45	19.45	19.55	19.65	19.75
	Large C&I	35.15	32.45	29.95	27.85	27.65	25.95	24.35	22.95	21.65	20.55	19.55	18.65	18.65	18.75	18.75
	MW-Scale	28.55	26.45	24.65	22.95	23.25	21.95	20.75	19.65	18.75	17.85	17.15	16.45	16.55	16.65	16.75
Capital	Residential	38.55	35.25	32.15	29.45	28.75	26.55	24.55	22.85	21.15	19.75	18.45	17.35	17.35	17.45	17.45
	Small C&I	36.75	33.85	31.25	28.85	28.55	26.75	25.05	23.45	22.15	20.95	19.85	18.85	18.95	19.05	19.15
	Large C&I	34.25	31.55	29.25	27.05	26.95	25.25	23.75	22.35	21.15	20.05	19.05	18.15	18.15	18.25	18.35
	MW-Scale	27.55	25.55	23.75	22.25	22.45	21.15	20.05	19.05	18.05	17.25	16.55	15.95	16.05	16.05	16.15
Downstate	Residential	36.75	33.55	30.65	28.05	27.45	25.35	23.45	21.75	20.15	18.85	17.55	16.45	16.55	16.65	16.65
	Small C&I	35.05	32.25	29.75	27.55	27.25	25.45	23.85	22.35	21.05	19.95	18.95	17.95	18.05	18.15	18.25
	Large C&I	32.65	30.15	27.85	25.85	25.75	24.05	22.65	21.35	20.15	19.15	18.15	17.35	17.35	17.35	17.45
	MW-Scale	26.35	24.45	22.75	21.15	21.45	20.25	19.15	18.15	17.25	16.45	15.85	15.25	15.25	15.35	15.45
NYC	Residential	44.45	40.55	36.95	33.75	32.55	29.95	27.65	25.55	23.65	21.95	20.35	19.05	19.05	19.15	19.15
	Small C&I	37.95	34.95	32.25	29.75	29.25	27.35	25.55	23.95	22.55	21.25	20.15	19.15	19.25	19.25	19.35
	Large C&I	35.35	32.55	30.05	27.85	27.55	25.75	24.15	22.75	21.45	20.25	19.25	18.35	18.35	18.35	18.45
	MW-Scale	28.45	26.35	24.45	22.85	22.95	21.55	20.35	19.25	18.35	17.45	16.65	16.05	16.15	16.15	16.25
Long Island	Residential	36.75	33.55	30.65	28.05	27.45	25.35	23.45	21.75	20.15	18.85	17.55	16.45	16.55	16.65	16.65
	Small C&I	35.05	32.25	29.75	27.55	27.25	25.45	23.85	22.35	21.05	19.95	18.95	17.95	18.05	18.15	18.25
	Large C&I	32.65	30.15	27.85	25.85	25.75	24.05	22.65	21.35	20.15	19.15	18.15	17.35	17.35	17.35	17.45
	MW-Scale	27.35	25.35	23.55	21.95	22.15	20.85	19.75	18.65	17.75	16.95	16.25	15.65	15.65	15.75	15.85

Table 124. High Cost LCOE Future: (Current Federal Incentives Cease After 2016), ¢/kWh Nominal

Location	Size	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Upstate	Residential	55.75	54.25	52.85	51.45	50.15	48.85	64.55	62.85	61.15	59.65	58.05	56.55	55.15	53.75	52.35
	Small C&I	55.15	53.75	52.45	51.25	50.15	48.95	64.45	62.85	61.35	59.95	58.55	57.25	55.95	54.65	53.45
	Large C&I	48.35	47.15	46.15	45.05	44.05	43.15	55.05	53.85	52.55	51.45	50.25	49.15	48.05	47.05	46.05
	MW-Scale	38.95	38.05	37.25	36.45	35.75	35.05	44.15	43.25	42.35	41.45	40.55	39.75	38.95	38.15	37.45
Capital	Residential	53.85	52.35	50.95	49.65	48.35	47.15	62.35	60.65	59.05	57.55	56.05	54.65	53.25	51.85	50.55
	Small C&I	53.45	52.15	50.95	49.75	48.65	47.55	62.45	60.95	59.55	58.15	56.85	55.55	54.25	53.05	51.85
	Large C&I	47.15	45.95	44.95	43.95	42.95	42.05	53.65	52.45	51.25	50.05	48.95	47.95	46.85	45.85	44.85
	MW-Scale	37.65	36.75	35.95	35.25	34.55	33.85	42.65	41.75	40.85	40.05	39.15	38.35	37.65	36.85	36.15
Downstate	Residential	51.25	49.85	48.55	47.35	46.05	44.95	59.35	57.75	56.25	54.75	53.35	52.05	50.65	49.45	48.15
	Small C&I	50.95	49.75	48.55	47.45	46.35	45.35	59.55	58.15	56.75	55.45	54.15	52.95	51.75	50.55	49.45
	Large C&I	44.95	43.85	42.85	41.85	40.95	40.05	51.25	50.05	48.85	47.75	46.75	45.65	44.65	43.75	42.75
	MW-Scale	35.95	35.15	34.35	33.65	32.95	32.25	40.75	39.85	38.95	38.15	37.45	36.65	35.95	35.25	34.55
NYC	Residential	61.85	60.15	58.55	56.95	55.45	54.05	71.75	69.85	67.95	66.15	64.35	62.75	61.05	59.45	57.95
	Small C&I	55.25	53.85	52.55	51.35	50.15	49.05	64.55	63.05	61.55	60.05	58.65	57.35	55.95	54.65	53.45
	Large C&I	48.55	47.35	46.25	45.25	44.25	43.25	55.35	54.05	52.85	51.65	50.45	49.35	48.25	47.15	46.15
	MW-Scale	38.85	37.95	37.15	36.35	35.55	34.85	44.15	43.15	42.25	41.35	40.45	39.65	38.75	37.95	37.25
Long Island	Residential	51.25	49.85	48.55	47.35	46.05	44.95	59.35	57.75	56.25	54.75	53.35	52.05	50.65	49.45	48.15
	Small C&I	50.95	49.75	48.55	47.45	46.35	45.35	59.55	58.15	56.75	55.45	54.15	52.95	51.75	50.55	49.45
	Large C&I	44.95	43.85	42.85	41.85	40.95	40.05	51.25	50.05	48.85	47.75	46.75	45.65	44.65	43.75	42.75
	MW-Scale	37.35	36.55	35.75	34.95	34.25	33.55	42.35	41.45	40.55	39.75	38.85	38.05	37.35	36.55	35.85

Table 125. Base Case PV Installed Cost Forecasts Supporting LCOE Analysis, by Project Size & Region, $/kW Nominal

Location	Size	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Upstate	Residential	6,348	5,979	5,631	5,305	4,997	4,734	4,485	4,249	4,026	3,814	3,634	3,480	3,348	3,236	3,146
	Small C&I	5,920	5,563	5,229	4,917	4,624	4,377	4,144	3,924	3,717	3,521	3,369	3,235	3,122	3,031	2,961
	Large C&I	5,072	4,766	4,480	4,212	3,962	3,750	3,550	3,362	3,184	3,017	2,886	2,772	2,675	2,597	2,537
	MW-Scale	4,183	3,977	3,782	3,598	3,423	3,283	3,148	3,019	2,896	2,779	2,719	2,643	2,579	2,528	2,490
Capital	Residential	6,348	5,979	5,631	5,305	4,997	4,734	4,485	4,249	4,026	3,814	3,634	3,480	3,348	3,236	3,146
	Small C&I	5,920	5,563	5,229	4,917	4,624	4,377	4,144	3,924	3,717	3,521	3,369	3,235	3,122	3,031	2,961
	Large C&I	5,072	4,766	4,480	4,212	3,962	3,750	3,550	3,362	3,184	3,017	2,886	2,772	2,675	2,597	2,537
	MW-Scale	4,183	3,977	3,782	3,598	3,423	3,283	3,148	3,019	2,896	2,779	2,719	2,643	2,579	2,528	2,490
Downstate	Residential	6,348	5,979	5,631	5,305	4,997	4,734	4,485	4,249	4,026	3,814	3,634	3,480	3,348	3,236	3,146
	Small C&I	5,920	5,563	5,229	4,917	4,624	4,377	4,144	3,924	3,717	3,521	3,369	3,235	3,122	3,031	2,961
	Large C&I	5,072	4,766	4,480	4,212	3,962	3,750	3,550	3,362	3,184	3,017	2,886	2,772	2,675	2,597	2,537
	MW-Scale	4,183	3,977	3,782	3,598	3,423	3,283	3,148	3,019	2,896	2,779	2,719	2,643	2,579	2,528	2,490
NYC	Residential	7,801	7,347	6,920	6,518	6,139	5,815	5,509	5,219	4,944	4,684	4,462	4,272	4,110	3,973	3,862
	Small C&I	6,473	6,082	5,717	5,376	5,057	4,786	4,531	4,291	4,064	3,851	3,684	3,537	3,414	3,314	3,238
	Large C&I	5,546	5,211	4,898	4,606	4,332	4,100	3,882	3,676	3,482	3,299	3,156	3,031	2,925	2,839	2,774
	MW-Scale	4,601	4,375	4,160	3,958	3,766	3,611	3,463	3,321	3,186	3,056	2,991	2,907	2,837	2,781	2,739
Long Island	Residential	6,348	5,979	5,631	5,305	4,997	4,734	4,485	4,249	4,026	3,814	3,634	3,480	3,348	3,236	3,146
	Small C&I	5,920	5,563	5,229	4,917	4,624	4,377	4,144	3,924	3,717	3,521	3,369	3,235	3,122	3,031	2,961
	Large C&I	5,072	4,766	4,480	4,212	3,962	3,750	3,550	3,362	3,184	3,017	2,886	2,772	2,675	2,597	2,537
	MW-Scale	4,387	4,171	3,967	3,774	3,591	3,443	3,302	3,167	3,038	2,914	2,852	2,772	2,705	2,652	2,612

Table 126. Low Case PV Installed Cost Forecasts Supporting LCOE Analysis, by Project Size & Region, $/kW Nominal

Location	Size	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Upstate	Residential	6,093	5,508	4,980	4,503	4,072	3,684	3,332	3,015	2,728	2,469	2,235	2,024	2,022	2,021	2,019
	Small C&I	5,713	5,181	4,702	4,270	3,880	3,529	3,211	2,925	2,666	2,433	2,223	2,033	2,034	2,035	2,036
	Large C&I	4,894	4,439	4,028	3,658	3,325	3,023	2,751	2,506	2,284	2,085	1,904	1,742	1,722	1,722	1,723
	MW-Scale	3,989	3,617	3,283	2,981	2,709	2,464	2,242	2,042	1,861	1,699	1,552	1,419	1,420	1,421	1,421
Capital	Residential	6,093	5,508	4,980	4,503	4,072	3,684	3,332	3,015	2,728	2,469	2,235	2,024	2,022	2,021	2,019
	Small C&I	5,713	5,181	4,702	4,270	3,880	3,529	3,211	2,925	2,666	2,433	2,223	2,033	2,034	2,035	2,036
	Large C&I	4,894	4,439	4,028	3,658	3,325	3,023	2,751	2,506	2,284	2,085	1,904	1,742	1,722	1,722	1,723
	MW-Scale	3,989	3,617	3,283	2,981	2,709	2,464	2,242	2,042	1,861	1,699	1,552	1,419	1,420	1,421	1,421
Downstate	Residential	6,093	5,508	4,980	4,503	4,072	3,684	3,332	3,015	2,728	2,469	2,235	2,024	2,022	2,021	2,019
	Small C&I	5,713	5,181	4,702	4,270	3,880	3,529	3,211	2,925	2,666	2,433	2,223	2,033	2,034	2,035	2,036
	Large C&I	4,894	4,439	4,028	3,658	3,325	3,023	2,751	2,506	2,284	2,085	1,904	1,742	1,722	1,722	1,723
	MW-Scale	3,989	3,617	3,283	2,981	2,709	2,464	2,242	2,042	1,861	1,699	1,552	1,419	1,420	1,421	1,421
NYC	Residential	7,487	6,767	6,117	5,530	5,000	4,521	4,088	3,698	3,345	3,026	2,738	2,478	2,477	2,475	2,473
	Small C&I	6,246	5,665	5,141	4,669	4,243	3,859	3,511	3,198	2,916	2,661	2,431	2,224	2,225	2,226	2,226
	Large C&I	5,351	4,853	4,405	4,000	3,635	3,306	3,008	2,740	2,498	2,279	2,083	1,905	1,883	1,883	1,884
	MW-Scale	4,388	3,979	3,611	3,280	2,980	2,710	2,466	2,246	2,048	1,868	1,707	1,561	1,562	1,563	1,563
Long Island	Residential	6,093	5,508	4,980	4,503	4,072	3,684	3,332	3,015	2,728	2,469	2,235	2,024	2,022	2,021	2,019
	Small C&I	5,713	5,181	4,702	4,270	3,880	3,529	3,211	2,925	2,666	2,433	2,223	2,033	2,034	2,035	2,036
	Large C&I	4,894	4,439	4,028	3,658	3,325	3,023	2,751	2,506	2,284	2,085	1,904	1,742	1,722	1,722	1,723
	MW-Scale	4,184	3,794	3,443	3,127	2,842	2,584	2,352	2,142	1,952	1,782	1,628	1,489	1,490	1,490	1,491

Table 127. High Case PV Installed Cost Forecasts Supporting LCOE Analysis, by Project Size & Region, $/kW Nominal

Location	Size	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Upstate	Residential	6,538	6,341	6,151	5,967	5,788	5,615	5,447	5,285	5,127	4,973	4,825	4,681	4,541	4,405	4,273
	Small C&I	6,118	5,940	5,769	5,604	5,444	5,289	5,138	4,992	4,851	4,714	4,582	4,453	4,329	4,207	4,089
	Large C&I	5,242	5,089	4,943	4,801	4,664	4,531	4,402	4,277	4,156	4,039	3,926	3,815	3,708	3,604	3,503
	MW-Scale	4,272	4,148	4,028	3,913	3,801	3,693	3,587	3,486	3,387	3,292	3,199	3,109	3,022	2,937	2,855
Capital	Residential	6,538	6,341	6,151	5,967	5,788	5,615	5,447	5,285	5,127	4,973	4,825	4,681	4,541	4,405	4,273
	Small C&I	6,118	5,940	5,769	5,604	5,444	5,289	5,138	4,992	4,851	4,714	4,582	4,453	4,329	4,207	4,089
	Large C&I	5,242	5,089	4,943	4,801	4,664	4,531	4,402	4,277	4,156	4,039	3,926	3,815	3,708	3,604	3,503
	MW-Scale	4,272	4,148	4,028	3,913	3,801	3,693	3,587	3,486	3,387	3,292	3,199	3,109	3,022	2,937	2,855
Downstate	Residential	6,538	6,341	6,151	5,967	5,788	5,615	5,447	5,285	5,127	4,973	4,825	4,681	4,541	4,405	4,273
	Small C&I	6,118	5,940	5,769	5,604	5,444	5,289	5,138	4,992	4,851	4,714	4,582	4,453	4,329	4,207	4,089
	Large C&I	5,242	5,089	4,943	4,801	4,664	4,531	4,402	4,277	4,156	4,039	3,926	3,815	3,708	3,604	3,503
	MW-Scale	4,272	4,148	4,028	3,913	3,801	3,693	3,587	3,486	3,387	3,292	3,199	3,109	3,022	2,937	2,855
NYC	Residential	8,035	7,794	7,560	7,334	7,114	6,901	6,695	6,495	6,300	6,112	5,929	5,752	5,580	5,413	5,251
	Small C&I	6,690	6,495	6,308	6,127	5,952	5,783	5,618	5,459	5,304	5,155	5,010	4,870	4,733	4,600	4,471
	Large C&I	5,731	5,565	5,404	5,249	5,099	4,954	4,813	4,677	4,544	4,416	4,292	4,172	4,055	3,941	3,830
	MW-Scale	4,699	4,562	4,431	4,304	4,181	4,062	3,946	3,834	3,726	3,621	3,519	3,420	3,324	3,231	3,140
Long Island	Residential	6,538	6,341	6,151	5,967	5,788	5,615	5,447	5,285	5,127	4,973	4,825	4,681	4,541	4,405	4,273
	Small C&I	6,118	5,940	5,769	5,604	5,444	5,289	5,138	4,992	4,851	4,714	4,582	4,453	4,329	4,207	4,089
	Large C&I	5,242	5,089	4,943	4,801	4,664	4,531	4,402	4,277	4,156	4,039	3,926	3,815	3,708	3,604	3,503
	MW-Scale	4,481	4,350	4,225	4,104	3,987	3,873	3,763	3,656	3,553	3,452	3,355	3,261	3,170	3,081	2,994

APPENDIX 5 – COST COMPARISON WITH OTHER RENEWABLES

A5.1. Introduction

The purpose of this chapter is to provide policymakers with insight into how the levelized cost of energy (LCOE) from PV compares to the levelized cost from other renewable energy technologies available in New York State. The cost comparison across technologies is based on research of a range of recent reports on both operating and proposed facilities, and includes estimated future costs. Comparison of future cost trends is important as the cost of some less mature technologies will decrease over time due to technological improvements and economies of scale, relative to more mature technologies.

The information gathered builds upon the New York Renewable Portfolio Standard (RPS) Cost Study (N.Y. PSC, 2011b) previously completed for NYSERDA and includes estimates of capital and operating costs for each of the following technologies:

- Onshore Wind (including two different project sizes)
- Offshore Wind (including high and low cost and performance estimates)
- Hydroelectric (consisting of new low-impact hydro, i.e., <30 MW, run-of-river, no new storage impoundment, and the incremental production associated with any upgrades to existing facilities so long as no new impoundments are created)
- Landfill gas
- Biomass (including greenfield[211] development, co-firing at existing coal plants, and repowering at existing or retired coal facilities)
- Tidal

This section relies on LCOE as a metric for comparing the different generating technologies. LCOE is not, however, the only useful means of making this comparison. Other comparison metrics may be helpful in evaluating the variability/intermittency, contribution to environmental externalities, and additional costs or savings opportunities in transmission and distribution. It is important to note that this section focuses only on resource costs, not the value of the energy, capacity and/or ancillary services produced (production profile). Aspects of each resource make them more or less valuable to the buyer of the power. For example,

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211 The term greenfield refers to a site without existing infrastructure related to the proposed facility. A greenfield project can also be referred to as a "new build."

the value of solar power can be greater than the value of wind power since PV output is concentrated in the on-peak period and can be located in the distribution system, avoiding distribution costs and avoiding line losses.

A5.2. Methodology

The cost estimates from the RPS Cost Study have been updated for all technologies through a combination of literature review of recent publicly available government and industry studies and programs, and evaluation of the actual installed costs of recent renewable projects. For each technology, costs are estimated for one or more representative project sizes. The goal of the research was to gather all the key inputs required to conduct an LCOE analysis. This analysis included all applicable federal incentives, but did not include any New York State incentives.

The relative economics of different renewable energy technologies are expected to change over time. This is due to differing rates of technological advance: less mature technologies such as PV, tidal, and offshore wind are expected to experience material cost decreases in coming years, while more mature technologies such as biomass, hydroelectric, and landfill gas technology costs are expected to be relatively stable. Onshore wind technology is maturing but is still experiencing material technological advances, so falls in between. The net cost of energy from different renewable energy technologies will also vary over time based on the availability of federal cash and tax incentives. The form and magnitude of these incentives vary in several ways across technologies and their availability is subject to frequent review and approval by Congress. In the past, this process has allowed key incentives to expire, followed by retroactive renewal. The current format, magnitude, eligibility, and expiration dates of key federal incentives include:

- The 30% Income Tax Credit (ITC) available to PV currently applies to projects placed in service on or before December 31, 2016.
- The Production Tax Credit (PTC) is available to wind, biomass, hydro, landfill gas and tidal facilities. The placed in service date for wind is December 31, 2012, and for other technologies December 31, 2013. The PTC is valued at 2.2 cents per kWh (2011$) for wind, and 1.1 cents per kWh (2011$) for all other modeled technologies.[212]
- The 30% ITC is available to all PTC-eligible technologies for projects placed in service on or before December 31, 2012.

[212] The higher PTC value is available to closed-loop biomass, but such technology is not modeled in this analysis.

Using these inputs, LCOE projections for each technology were calculated using the National Renewable Energy Laboratory's CREST (Cost of Renewable Energy Spreadsheet Tool) model.[213] Inputs to the CREST model include capital and operating costs, system performance, and incentive and financing parameters. The model is designed to calculate the cost of energy, or minimum revenue per unit of production needed, for the modeled renewable energy project to meet its equity investors' assumed minimum required after-tax rate of return.[214]

A5.3. Modeling Inputs

Onshore Wind

According to Lawrence Berkeley National Laboratory's 2010 Wind Technologies Market Report, Onshore wind per-unit installed costs have risen since 2002, but leveled off, have started to decline, and are expected to continue their decline in 2011 and 2012 due to reduced turbine costs. The average 2010 installed costs were $2155/kW nationally according to LBNL. Installed costs in the East region, which includes New York, were a little higher than the national average. Installed costs were assumed that are lower than the 2010 LBNL national average for *large* wind farms and higher than the national average for *small* wind farms modeled in this section (Wiser & Bolinger, 2011).

The capacity factor assumptions are loosely based upon the wind potential study completed by AWS TruePower as part of the RPS Cost Study. These values are then adjusted to account for two opposing trends – first, that while some New York wind facilities have achieved their output expectations, several have demonstrated production considerably less than originally expected; and second, that the increasing presence of higher hub heights and longer blade diameters combined with other technological advances is expected to enable greater production from the same wind resource. As a result, all onshore wind facilities are modeled using a 32% capacity factor – which is intended to represent an average, forward-looking perspective on wind generator performance in New York.

Operations and maintenance costs were more difficult to obtain. No variable O&M cost were assumed for wind projects, and estimated fixed O&M using a California Energy Commission (2010) report. In the report, O&M costs were split up into a number of categories, and the insurance and other fixed O&M costs were aggregated. Property taxes were not included, as they are separately accounted for in the CREST model, and were conformed to the assumption made in the solar LCOE analysis. The cost of small wind project O&M was assumed to be 5% higher than medium and large products due to diseconomies of scale. All future year O&M cost estimates were calculated using a GDP Price Index.

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213 The model and supporting documentation are available at the NREL website: http://financere.nrel.gov/finance/content/CREST-model

214 Sustainable Energy Advantage developed the CREST model for NREL and has adapted the existing model to accommodate the fuel cost inputs necessary to calculate the cost of energy from biomass facilities necessary to complete the cost comparison outlined in this section.

An onshore wind experience curve was also taken from the study done for the CA Energy Commission (2010). To this end, onshore wind technology costs are expected to decline less than 1% per year in real dollars, and are expected to increase on a nominal basis over the duration of the study period.[215] It is also important to note that while the estimated cost of interconnecting wind generators to the transmission system is included in this analysis, the cost of potential network transmission upgrades (e.g., between Upstate and NYC) are not included.

Table 128. Onshore Wind Assumptions

	MODELED PROJECT SIZE (MW)	CAPACITY FACTOR	CAPITAL COSTS ($/KW)	INTER-CONNECT ($/KW)	FIXED O&M*($/KW)-YR	VARIABLE O&M ($/MWH)	TECHNOLOGY DECLINE RATE PER YEAR
Large	125	32%	$1,900	128	$38	$0	< 1%
Small	15	32%	$2,500	128	$40	$0	< 1%

*Property taxes of $35/kW are modeled separately and assumed to decline over the life of the project as it depreciates.

Offshore Wind

Predicting the costs of offshore wind is challenging because of the lack of development history in the United States. Several projects have received contracts for their power, but none have actually been constructed.[216] Although several offshore wind projects exist in Europe, their cost profile cannot be directly compared to potential United States projects, because the US does not yet have the construction experience or resulting infrastructure found in Europe.[217] Specialty ships are needed to construct offshore wind farms and the Jones Act prohibits European ships from operating in the United States.

This lack of US project data makes it difficult to predict new plant costs and has yielded a wide range of cost estimates, from $,3680/kW to $7,774/kW.[218] A variety of sources were examined to estimate offshore wind costs including the following government reports:

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215 The Model Documentation of the Renewable Fuels Module of the National Energy Modeling System states that EIA assumed that base capital costs for wind power remained constant throughout the study period, but that as more wind in a region was built additional transmission investments would be required. This resulted in a increasing capital cost over time. http://www.eia.gov/FTPROOT/modeldoc/m069(2011).pdf See page 58 and 72.

216 Block Island (28 MW) received a PPA for 24.4 cents per KWh and Cape Wind (486 MW) received a PPA for 18.7 cents per KWh each with a 3.5% escalator.

217 Europe currently has 2,946 MW from 45 wind farms in nine European countries. Ten wind farms, totaling 3,000 MW, are currently under construction.

218 $3,680/kW is the low estimate for an onshore wind farm from the NYSERDA study, “New York’s Offshore Wind Energy Development Potential in the Great Lakes”.

- **EIA 2011 Annual Energy Outlook.** EIA estimated capital costs to be $5,975/kW on average in the United States and $7,774/kW in New York City and $5,906 in Syracuse. Offshore wind development is unlikely to take place in either New York City or Syracuse. Rather, development would more likely take place off the south shore of Long Island or in the Great Lakes. Development costs in the lakes would likely be similar to Syracuse and costs off Long Island more expensive than Syracuse, but less than New York City (U.S. EIA, 2010)

- **U.S. DOE Offshore Wind Strategic Work Plan.** This plan was prepared by the United States Department of Energy to outline the actions it will take to develop an offshore wind industry in the United States. This report shows a potential path to reduced offshore wind costs in 2030. It estimates 2010 costs at $4,259/kW and cites NREL as the source of this number (U.S. DOE, 2011c)

- **NYSERDA Great Lakes Offshore Wind Potential Study.** This study reports cost information for projects built in Europe and projects scheduled to be built in the next three years. It reports a range of $3400 to $5800 per kW for European projects under construction or scheduled to be built in the next three years. It uses this range as the basis for low, typical and high installed costs estimates of $3860, $4600 and $5750 respectively (NYSERDA, 2010d)

- **NREL Large Scale Wind Power in the United States.** This NREL report reviews wind projects installed in Europe and planned projects in both the United States and Europe. It reports and average installed cost of $4252/kW in $2008 for projects installed in 2009 and estimates the average price for projects installed between 2010 and 2015 to be $4327/kW in $2008 (NREL, 2010).

Based on these sources, 2018 installed costs were estimated to be $5346/kW (in 2011$) for a high cost estimate and $3302/kW (in 2011$) for a low cost estimate. These capital costs are more than double those of onshore wind, due to the fact that the turbines must be designed to withstand the marine environment, additional foundation costs and the costs of transporting and installing at sea. It is expected that similar to the historical onshore experience, these prices will decline over time as the industry grows, manufacturing, assembly and installation infrastructure is developed in the U.S., technology improves and more experience is gained.

A technology cost decline rate was assumed for offshore wind to reflect the expected cost declines as the industry grows. Figure 62 shows graphically the estimates from the four sources described above. This data was used to develop the high and low cost trajectory. Another indication of how costs would decline over time was provided by data from the onshore wind industry. The “2010 Wind Technologies Market Report”, written by the Lawrence Berkeley National Laboratory and published by the United States Department of Energy, contains capital cost information for onshore wind over time. This information shows that onshore wind costs declined about 5% per year in the period from 1982 to 2002 (Wiser & Bolinger, 2011). It was assumed that offshore wind costs will decrease at 1% per year (in nominal dollars) in a high-cost trajectory case, and 3.5% per year (in nominal dollars) in a low-cost trajectory case.

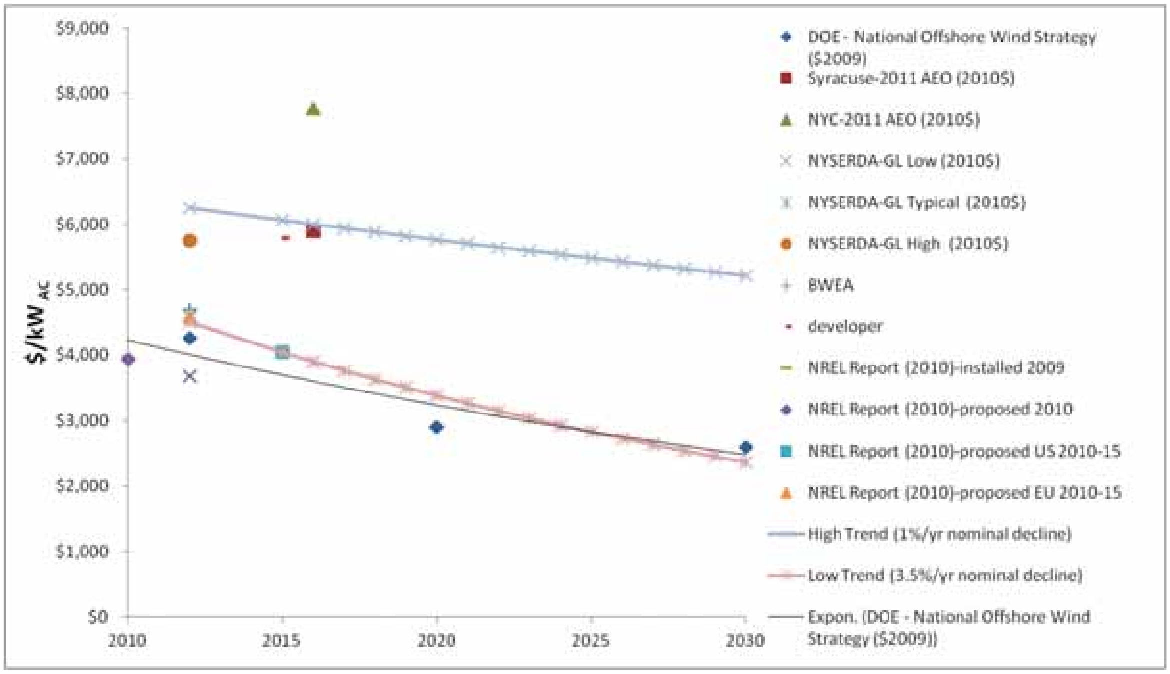

Figure 62. Range of Offshore Wind Energy Cost Futures

As with onshore wind it was assumed no variable O&M cost for offshore wind projects, and estimated fixed O&M using a California Energy Commission report developed by KEMA in 2009 (California Energy Commission, 2010).

The capacity factor assumption of 38% in the high cost case and 42% in the low cost case is based upon inspection of the NREL offshore wind maps and discussions with NREL about the capacity factors achieved from different wind speeds. Both of these are based upon an ocean installation.

Table 129. Offshore Wind Assumptions

	MODELED PROJECT SIZE	CAPACITY FACTOR	CAPITAL COSTS ($/KW$_{AC}$) (2018)	FIXED O&M[219] ($/KW$_{AC}$)	VARIABLE O&M ($/MWH)	TECHNOLOGY DECLINE RATE PER YEAR
Offshore : High Cost	300	38%	$5,884	73.0	$0	1%
Offshore : Low Cost	300	42%	$3,634	73.0	$0	3.5%

Biomass

The costs of deploying biomass resources was analyzed for three types of facilities:

- Greenfield (new build) biomass facilities
- Repowering existing or retired coal facilities to burn biomass
- Co-firing biomass fuel at existing coal facilities

Not as many recent sources of biomass costs are available as they are for the other technologies. Therefore, the previous cost study data and EIA's Annual Energy Outlook were relied upon . Specifically, the following sources were used:

- Greenfield Biomass: The 2011 EIA Annual Energy Outlook gives an estimate of greenfield biomass using the fluidized bed technology. Capital cost estimates are given by city and cost estimate for Syracuse, NY were used (U.S. EIA, 2010). Operations and maintenance costs also come from the 2011 Annual Energy Outlook
- Repower: The installed cost and fixed and variable operations and maintenance estimates for repowering existing coal plants is the same as the RPS Cost Study, escalated for inflation
- Co-firing: The 2011 EIA Annual Energy Outlook did not offer an estimate of co-firing capital costs but the 2010 Annual Energy Outlook did include one. The 2010 Annual Energy Outlook was used as the source of capital costs. Fixed and variable operations and maintenance costs came from the same source
- Biomass Fuel Costs. Interviews with industry participants provided the basis for an estimate of biomass fuel costs of $28 per green ton, obtained through. This estimate includes an assumed 2.1

219 Property taxes of $35/kW are modeled separately and assumed to decline over the life of the project as it depreciates.

gallons per green ton of diesel fuel, at $4.00 per gallon, assuming a 50 mile radius and a 27 ton load. The conversion assumes 9.25 mmBtu per green ton at 45% moisture content.

Table 130. Biomass Assumptions

	CAPACITY FACTOR	MODELED PROJECT SIZE (MW_{AC})	2011 TOTAL INSTALLED COST ($\$/KW_{AC}$)	2011 FIXED O&M[220] $/KW-YR	2011 VARIABLE O&M COSTS $/MWH	FUEL HEAT RATE (BTU/KWH)	FUEL COSTS $/MMBTU (2011)
Greenfield	85%	25	$4,250	$65.5	$5	13,000	$3.00
Repower	85%	25	$1,300	$48.0	$11	13,800	$3.00
Co-firing	70%	20	$375	$0	$6	11,500	$3.00

Hydropower

The Main Tier of the RPS includes two categories of hydroelectric resources: (i) *new* low-impact hydro, defined as new facilities of up to 30 MW, so long as they are run-of-river, with no new storage impoundment, and (ii) the incremental production associated with any upgrades to existing facilities so long as no new impoundments are created. The first category has been subdivided into projects less than five MW and projects between five and 30 MW, because hydro cost is a strong function of size. The three types of facilities modeled are:

- New Low-Impact Hydro (5-30 MW)
- Very Small New Hydro (<= 5 MW) and
- Hydro Upgrades.

The capacity factors for hydro in New York State were taken from the RPS Cost Study data for capacity and actual historical generation for New York hydro facilities (N.Y. PSC, 2011a) . Hydroelectric generation capacity factors by independent power producers were used as a proxy for low impact hydro and hydro upgrades, while hydroelectric commercial generators were used as a proxy for very small generators.

It is important to note that while large hydroelectric resources (e.g., those currently under contract from Hydro Quebec) are not eligible to meet the current RPS requirement, these resources play an important role in New York's energy portfolio, are counted in the baseline towards New York's overall renewable energy goals, and may be eligible for future policies and portfolio requirements. To this end, additional large

220 Property taxes of $35/kW are modeled separately and assumed to decline over the life of the project as it depreciates.

hydroelectric purchases may be considered in the future. This study, however, focused on in-state resources.

Table 131. Hydropower Capacity Factors

NY PROJECT TYPE	CAPACITY FACTOR
Very Small Hydro	28.5%
Low Impact Hydro	46%
Hydro Upgrades	46%

The Idaho National Laboratory (INL) created a database to estimate total installed cost and operating costs for individual new hydro facilities in the United States.[221] Using this database, the New York projects in this database were grouped by project size and type to calculate an average cost for each project size and type. The higher end of each group's capital costs was estimated as one standard deviation above the average cost.

Table 132. Hydropower Assumptions[222]

2011 $	VERY SMALL NEW HYDRO (0-5 MW_{AC})	NEW LOW IMPACT HYDRO (5-30 MW_{AC})	HYDRO UPGRADES
Installed Cost ($/kW)	$5,000	$3850	$2,500
Fixed O&M ($/kW-year)	$26	$17	$24
Variable O&M ($/kWh)	$6	$4	$6

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Landfill Gas

Landfill gas costs have not changed since the most recent update to the RPS Cost Study (N.Y. PSC, 2011b). The previous estimates were escalated with inflation.

221 The INL database can be found at http://hydropower.inel.gov/resourceassessment/d/ihred-29apr03.xls.

222 Note: The numbers from the INL database were in 2002 dollars. These costs were escalated using inflation. Property tax values are included in these O&M assumptions.

Table 133. Landfill Gas Assumptions

	MODELED PROJECT SIZE (MW_{AC})	CAPACITY FACTOR	CAPITAL COSTS ($\$/KW_{AC}$)	FIXED O&M[223] ($/KW-YR)	VARIABLE O&M ($/MWH)	TECHNOLOGY DECLINE RATE PER YEAR
Landfill Gas	5	85%	$2500	$75	$13	0%

Tidal

Tidal energy is a technology on the cusp of commercialization in the United States. With the lack of development history, estimating installed costs is difficult. The primary source of information for our estimates is a report done by Synapse Energy Economics for the Nova Scotia Utility and Review Board (Synapse Energy Economics, 2010). Nova Scotia was setting its rates for a feed-in-tariff for tidal energy and this report contains cost information on several tidal projects. The installed costs for these projects ranged from $3900/kW to 17,000/kW and O&M costs ranged from $28/kW/year to $723/kW/year. Based on this information the installed costs were estimated to be $10,000/kW for a 5 MW project and O&M costs to be $400/kW/year. It was estimated that costs will decline 5% per year as the technology is commercialized.

The Tidal costs are included in Table 134 below.

Table 134. Tidal Assumptions

	MODELED PROJECT SIZE (MW_{AC})	CAPACITY FACTOR	CAPITAL COSTS ($\$/KW_{AC}$)	FIXED O&M ($/KW-YR)	VARIABLE O&M ($/MWH)	TECHNOLOGY DECLINE RATE PER YEAR
Tidal Project	5	40%	$10,000	$365	$0	5%

*Property taxes of $35/kW are modeled separately and assumed to decline over the life of the project as it depreciates.

A5.4 Financing Assumptions

The modeled financing assumptions are based on research, proprietary benchmarks, and best estimates of the commercial terms available from banks and equity investors currently active in the market. For the purpose of estimating the cost of energy, all technologies are assumed financed on project-specific terms. To this end, debt quantities are limited to an amount that the project can reasonably repay, subject to

223 Property taxes of $35/kW are modeled separately and assumed to decline over the life of the project as it depreciates.

minimum debt service coverage ratios. Debt terms assume a power purchase agreement, or other long-term revenue guarantee, of equal or greater duration. The cost of equity assumes that a single investor contributes all equity to the project and monetizes all available cash and tax benefits.

Table 135. Financing Assumptions

	CONSTRUCTION PERIOD (MONTHS) @ 6% INTEREST	PERMANENT D/E RATIO	COST OF DEBT (%)	DEBT TERM (YEARS)	COST OF EQUITY (%)
Onshore Wind (Large)	12	55 :45	7.0%	15	11.0%
Onshore Wind (Medium)	9	55 :45	8.0%	15	12.0%
Onshore Wind (Small)	6	55 :45	8.5%	15	13.0%
Offshore Wind	18	70 :30	10.0%	15	14.5%
Biomass: Greenfield	24	60 :40	8.0%	15	13.5%
Biomass : Repower	12	50 :50	8.0%	15	12.0%
Biomass : Co-firing	12	50 :50	8.0%	10	12.0%
Hydro : New, <30MW	24	60 :40	8.0%	20	13.5%
Hydro : Upgrades	12	65 :35	8.0%	20	12.0%
Hydro : New, 1 MW	18	70 :30	8.0%	20	13.5%
Landfill Gas	12	50 :50	8.0%	15	13.5%
Tidal	24	0 :100	NA	NA	15.0%

A5.5 Tax Incentives

All technologies are assumed to be financed in a manner that allows for full and efficient monetization of all available tax benefits. This primarily refers to the federal PTC and both federal and state depreciation deductions. For the purpose of this analysis, and for consistency with the solar LCOE modeling conducted in C-4, the federal PTC is assumed to decline to 50% of face value over a five-year period beginning with the year after the current expiration date. The majority of depreciation benefits are assumed to accrue via the five-year MACRS schedule, although a minority of costs is assumed either depreciated on other schedules or not depreciable at all.

A5.6 Levelized Cost of Energy

The LCOEs calculated for each technology using the CREST models are provided in both real and nominal dollars below. Charts are also provided; the first compares all modeled technologies in both 2011 and 2025; the second compares the three solar cost cases to both onshore and offshore wind for all years from 2011 to 2025.

Table 136. Levelized Cost by Technology and Year (Real, 2011 $)

	TECHNOLOGY	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Onshore Wind	Large	8.35	8.25	8.49	8.79	8.97	9.31	9.55	9.50	9.45	9.38	9.31	9.32	9.25	9.20	9.16
	Small	12.15	12.00	12.18	12.49	12.78	13.04	13.37	13.32	13.26	13.11	13.10	13.01	12.94	12.95	12.91
Offshore Wind	High Cost								24.08	23.35	22.61	21.89	21.19	20.54	20.01	19.45
	Low Cost								14.19	13.43	12.77	12.14	11.52	10.94	10.48	9.97
Biomass	Greenfield	13.45	13.48	13.44	13.54	13.52	13.58	13.63	13.58	13.43	13.35	13.26	13.09	13.02	12.95	12.83
	Repower	8.65	8.54	8.59	8.69	8.69	8.68	8.75	8.63	8.52	8.39	8.26	8.14	8.03	8.00	7.91
	Co-fire	5.95	5.88	5.87	5.75	5.72	5.59	5.46	5.42	5.30	5.25	5.20	5.07	5.03	4.92	4.89
Hydropower	Low Impact New	11.05	11.01	11.11	11.35	11.48	11.58	11.77	11.76	11.74	11.70	11.73	11.76	11.71	11.75	11.73
	Upgrades	6.05	6.07	6.16	6.32	6.46	6.59	6.79	6.81	6.74	6.74	6.73	6.72	6.72	6.80	6.73
	Very Small	22.55	22.57	22.66	22.85	23.00	23.12	23.22	23.29	23.26	23.28	23.26	23.24	23.23	23.24	23.28
	Landfill Gas	6.45	6.47	6.55	6.79	6.92	7.04	7.15	7.16	7.16	7.15	7.14	7.20	7.18	7.17	7.17
	Tidal	72.05	68.96	66.32	64.05	61.95	59.94	57.95	56.09	54.21	52.39	50.63	48.97	47.30	45.71	44.10
Solar (Capital, MW-Scale)	Low	27.55	25.23	23.04	21.14	20.86	19.22	17.81	16.53	15.30	14.26	13.34	12.54	12.33	12.05	11.88
	Base	33.55	31.95	30.22	28.55	27.00	25.67	25.44	25.12	24.79	24.35	24.23	23.16	22.31	21.59	20.92
	High	37.65	36.29	34.88	33.49	32.11	30.76	37.88	36.22	34.62	33.12	31.57	30.16	28.91	27.67	26.59

Table 137. Levelized Cost by Technology and Year (Nominal $)

	TECHNOLOGY	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Onshore Wind	Large	8.35	8.35	8.75	9.25	9.65	10.25	10.75	10.95	11.15	11.35	11.55	11.85	12.05	12.25	12.45
	Small	12.15	12.15	12.55	13.15	13.75	14.35	15.05	15.35	15.65	15.85	16.25	16.55	16.85	17.25	17.55
Offshore Wind	High Cost								27.75	27.55	27.35	27.15	26.95	26.75	26.65	26.45
	Low Cost								16.35	15.85	15.45	15.05	14.65	14.25	13.95	13.55
Biomass	Greenfield	13.45	13.65	13.85	14.25	14.55	14.95	15.35	15.65	15.85	16.15	16.45	16.65	16.95	17.25	17.45
	Repower	8.65	8.65	8.85	9.15	9.35	9.55	9.85	9.95	10.05	10.15	10.25	10.35	10.45	10.65	10.75
	Co-fire	5.95	5.95	6.05	6.05	6.15	6.15	6.15	6.25	6.25	6.35	6.45	6.45	6.55	6.55	6.65
Hydropower	Low Impact New	11.05	11.15	11.45	11.95	12.35	12.75	13.25	13.55	13.85	14.15	14.55	14.95	15.25	15.65	15.95
	Upgrades	6.05	6.15	6.35	6.65	6.95	7.25	7.65	7.85	7.95	8.15	8.35	8.55	8.75	9.05	9.15
	Very Small	22.55	22.85	23.35	24.05	24.75	25.45	26.15	26.85	27.45	28.15	28.85	29.55	30.25	30.95	31.65
	Landfill Gas	6.45	6.55	6.75	7.15	7.45	7.75	8.05	8.25	8.45	8.65	8.85	9.15	9.35	9.55	9.75
	Tidal	72.05	69.95	68.45	67.25	66.15	65.15	64.15	63.25	62.25	61.35	60.55	59.85	59.05	58.25	57.35

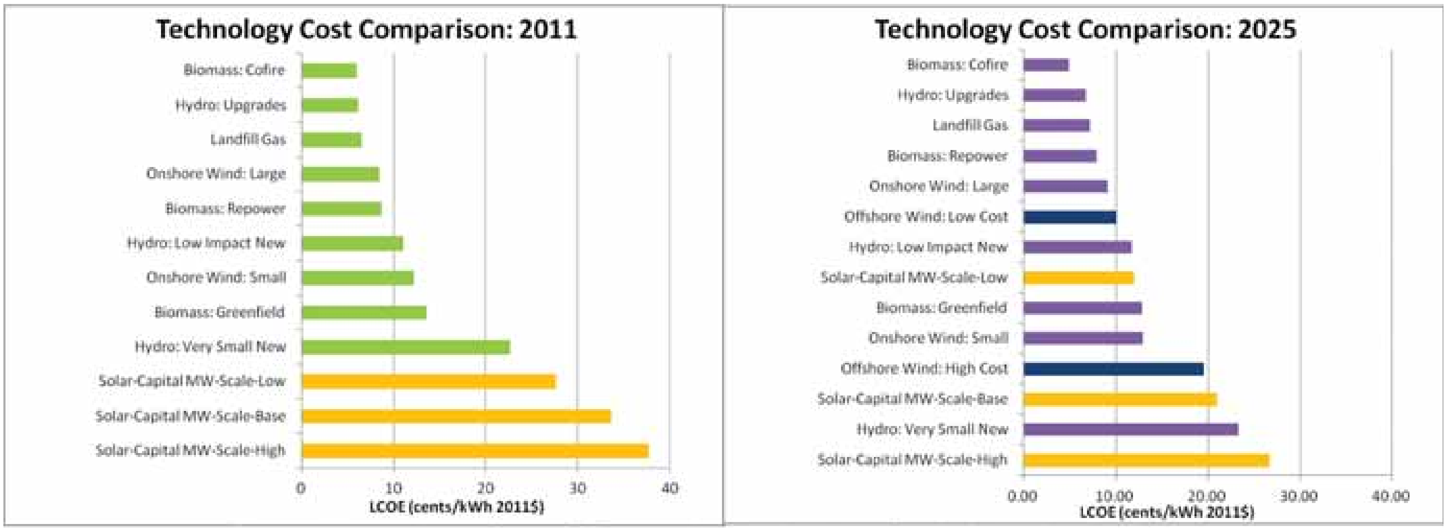

Figure 63. Levelized Cost of Energy, by Technology for 2011 and 2025 (2011$)

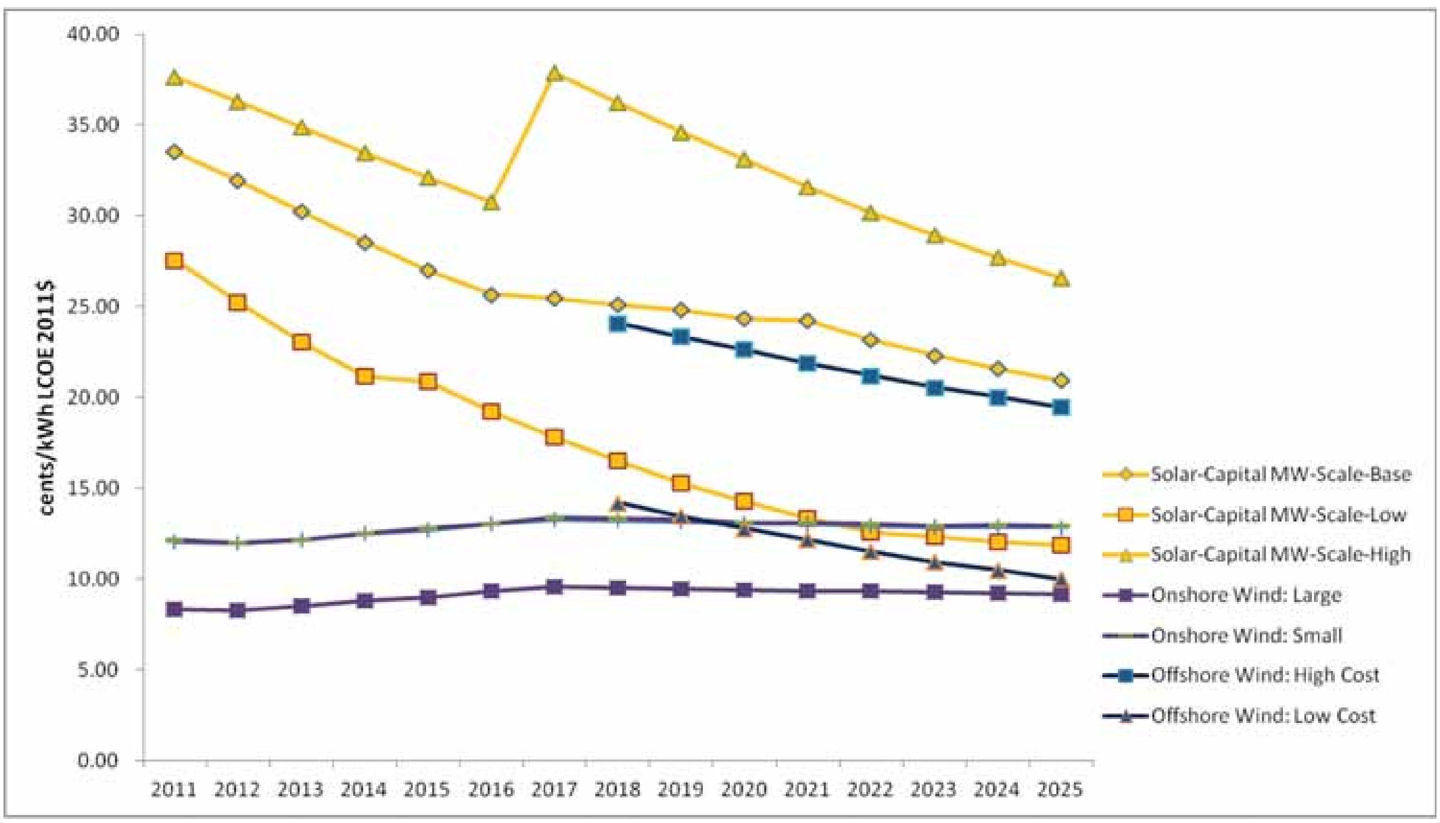

Figure 64. Levelized Cost of Energy, Comparison of PV and Wind from 2011-2025 (2011$)

Figure 64 shows the estimated cost trajectories of wind and solar only. A comparison of PV to wind energy may be more instructive than to other technologies, as wind is presently the only other technology with both a high installation growth rate and substantial additional resource potential. Wind energy is likely to be the marginal – and therefore price-setting – resource for compliance with policies that require the development of new, large scale renewable energy facilities. Other resources may represent lower cost supply in limited quantities.

APPENDIX 6 – COST & BENEFITS ANALYSIS DETAILS (CH. 5)

Table 138.Summary Metrics, Base PV Scenario vs. High Cost and Low Cost @ 3 Discount Rates

		Base PV Scenario				High Cost				Low Cost			
Criteria	**Metric (units)**	**2013-2049**	**Thru 2017**	**Thru 2022**	**Thru 2032**	**2013-2049**	**Thru 2017**	**Thru 2022**	**Thru 2032**	**2013-2049**	**Thru 2017**	**Thru 2022**	**Thru 2032**
Wholesale Price Suppression	(NPV M 2011$) Disc. Rate = L	(4,378)	(626)	(2,229)	(4,090)	(4,378)	(626)	(2,229)	(4,090)	(4,378)	(626)	(2,229)	(4,090)
	(NPV M 2011$) Disc. Rate = M	(3,282)	(547)	(1,825)	(3,125)	(3,282)	(547)	(1,825)	(3,125)	(3,282)	(547)	(1,825)	(3,125)
	(NPV M 2011$) Disc. Rate = H	(2,010)	(428)	(1,278)	(1,958)	(2,010)	(428)	(1,278)	(1,958)	(2,010)	(428)	(1,278)	(1,958)
Net Cost Impact (Zero Carbon)	(NPV M 2011$) Disc. Rate = L	4,538	(9)	106	2,344	13,141	245	1,671	7,888	(2,270)	(224)	(1,032)	(1,972)
	(NPV M 2011$) Disc. Rate = M	2,638	2	87	1,533	8,100	226	1,350	5,449	(1,657)	(190)	(833)	(1,505)
	(NPV M 2011$) Disc. Rate = H	1,051	15	65	726	3,655	195	925	2,871	(976)	(139)	(565)	(930)
Net Cost Impact (Low Carbon)	(NPV M 2011$) Disc. Rate = L	3,830	(61)	(55)	1,898	12,433	193	1,510	7,442	(2,979)	(276)	(1,193)	(2,418)
	(NPV M 2011$) Disc. Rate = M	2,183	(45)	(46)	1,211	7,645	179	1,217	5,127	(2,112)	(236)	(966)	(1,827)
	(NPV M 2011$) Disc. Rate = H	825	(22)	(30)	540	3,429	157	830	2,685	(1,201)	(176)	(661)	(1,116)
Net Cost Impact (High Carbon)	(NPV M 2011$) Disc. Rate = L	(482)	(376)	(1,034)	(817)	8,120	(122)	531	4,727	(7,291)	(591)	(2,172)	(5,133)
	(NPV M 2011$) Disc. Rate = M	(590)	(326)	(855)	(749)	4,872	(102)	407	3,166	(4,885)	(517)	(1,775)	(3,787)

		Base PV Scenario				High Cost				Low Cost			
Criteria	Metric (units)	2013-2049	Thru 2017	Thru 2022	Thru 2032	2013-2049	Thru 2017	Thru 2022	Thru 2032	2013-2049	Thru 2017	Thru 2022	Thru 2032
	(NPV M 2011$) Disc. Rate = H	(549)	(252)	(609)	(591)	2,055	(73)	251	1,554	(2,575)	(407)	(1,239)	(2,247)

Table 139.Summary Metrics, Base PV Scenario vs. Alt-A and Alt-B Deployments @ 3 Discount Rates

		Base PV Scenario				Alt-A Deployment				Alt-B Deployment			
Criteria	**Metric (units)**	**2013-2049**	**Thru 2017**	**Thru 2022**	**Thru 2032**	**2013-2049**	**Thru 2017**	**Thru 2022**	**Thru 2032**	**2013-2049**	**Thru 2017**	**Thru 2022**	**Thru 2032**
Wholesale Price Suppression	(NPV M 2011$) Disc. Rate = L	(4,378)	(626)	(2,229)	(4,090)	(5,367)	(816)	(2,775)	(4,991)	(2,422)	(502)	(1,184)	(1,964)
	(NPV M 2011$) Disc. Rate = M	(3,282)	(547)	(1,825)	(3,125)	(4,026)	(714)	(2,277)	(3,822)	(1,777)	(438)	(986)	(1,528)
	(NPV M 2011$) Disc. Rate = H	(2,010)	(428)	(1,278)	(1,958)	(2,475)	(561)	(1,601)	(2,407)	(1,075)	(342)	(711)	(993)
Net Cost Impact (Zero Carbon)	(NPV M 2011$) Disc. Rate = L	4,538	(9)	106	2,344	3,203	(202)	(473)	1,251	6,560	98	1,101	4,450
	(NPV M 2011$) Disc. Rate = M	2,638	2	87	1,533	1,685	(169)	(392)	706	4,162	95	885	3,107
	(NPV M 2011$) Disc. Rate = H	1,051	15	65	726	496	(120)	(276)	210	1,976	89	602	1,668
Net Cost Impact (Base Carbon)	(NPV M 2011$) Disc. Rate = L	3,830	(61)	(55)	1,898	2,511	(251)	(620)	824	5,838	48	935	3,984
	(NPV M 2011$) Disc. Rate = M	2,183	(45)	(46)	1,211	1,243	(213)	(513)	399	3,696	51	748	2,771

		Base PV Scenario				Alt-A Deployment				Alt-B Deployment			
Criteria	**Metric (units)**	**2013-2049**	**Thru 2017**	**Thru 2022**	**Thru 2032**	**2013-2049**	**Thru 2017**	**Thru 2022**	**Thru 2032**	**2013-2049**	**Thru 2017**	**Thru 2022**	**Thru 2032**
	(NPV M 2011$) Disc. Rate = H	825	(22)	(30)	540	280	(156)	(363)	34	1,744	53	505	1,475
Net Cost Impact (High Carbon)	(NPV M 2011$) Disc. Rate = L	(482)	(376)	(1,034)	(817)	(1,706)	(548)	(1,515)	(1,775)	1,442	(254)	(78)	1,146
	(NPV M 2011$) Disc. Rate = M	(590)	(326)	(855)	(749)	(1,447)	(478)	(1,254)	(1,468)	857	(219)	(86)	725
	(NPV M 2011$) Disc. Rate = H	(549)	(252)	(609)	(591)	(1,035)	(374)	(895)	(1,035)	331	(166)	(86)	300

Table 140. Summary Metrics, Base PV Scenario vs. High Gas @ 3 Discount Rates

		Base PV Scenario				High Gas			
Criteria	**Metric (units)**	**2013-2049**	**Thru 2017**	**Thru 2022**	**Thru 2032**	**2013-2049**	**Thru 2017**	**Thru 2022**	**Thru 2032**
Wholesale Price Suppression	(NPV M 2011$) Disc. Rate = L	(4,378)	(626)	(2,229)	(4,090)	(5,102)	(692)	(2,047)	(4,603)
	(NPV M 2011$) Disc. Rate = M	(3,282)	(547)	(1,825)	(3,125)	(3,726)	(608)	(1,686)	(3,454)
	(NPV M 2011$) Disc. Rate = H	(2,010)	(428)	(1,278)	(1,958)	(2,197)	(481)	(1,195)	(2,106)
Net Cost Impact (Zero Carbon)	(NPV M 2011$) Disc. Rate = L	4,538	(9)	106	2,344	2,652	(105)	172	1,273
	(NPV M 2011$) Disc. Rate = M	2,638	2	87	1,533	1,507	(86)	131	818
	(NPV M 2011$) Disc. Rate = H	1,051	15	65	726	573	(59)	82	373
Net Cost Impact (Base Carbon)	(NPV M 2011$) Disc. Rate = L	3,830	(61)	(55)	1,898	2,095	(135)	62	905
	(NPV M 2011$) Disc. Rate = M	2,183	(45)	(46)	1,211	1,149	(113)	42	555

		Base PV Scenario				High Gas			
Criteria	Metric (units)	2013-2049	Thru 2017	Thru 2022	Thru 2032	2013-2049	Thru 2017	Thru 2022	Thru 2032
	(NPV M 2011$) Disc. Rate = H	825	(22)	(30)	540	398	(81)	18	226
Net Cost Impact (High Carbon)	(NPV M 2011$) Disc. Rate = L	(482)	(376)	(1,034)	(817)	(1,294)	(319)	(605)	(1,340)
	(NPV M 2011$) Disc. Rate = M	(590)	(326)	(855)	(749)	(1,030)	(278)	(506)	(1,041)
	(NPV M 2011$) Disc. Rate = H	(549)	(252)	(609)	(591)	(669)	(216)	(368)	(666)

Table 141. Summary Metrics, Base PV Scenario vs. Indian Point Continued Operation @ 3 Discount Rates

		Base PV Scenario				Indian Point			
Criteria	Metric (units)	2013-2049	Thru 2017	Thru 2022	Thru 2032	2013-2049	Thru 2017	Thru 2022	Thru 2032
Wholesale Price Suppression	(NPV M 2011$) Disc. Rate = L	(4,378)	(626)	(2,229)	(4,090)	(4,573)	(680)	(2,103)	(4,234)
	(NPV M 2011$) Disc. Rate = M	(3,282)	(547)	(1,825)	(3,125)	(3,390)	(593)	(1,729)	(3,206)
	(NPV M 2011$) Disc. Rate = H	(2,010)	(428)	(1,278)	(1,958)	(2,044)	(462)	(1,218)	(1,982)
Net Cost Impact (Zero Carbon)	(NPV M 2011$) Disc. Rate = L	4,538	(9)	106	2,344	4,382	(52)	257	2,237
	(NPV M 2011$) Disc. Rate = M	2,638	2	87	1,533	2,559	(35)	205	1,482
	(NPV M 2011$) Disc. Rate = H	1,051	15	65	726	1,038	(11)	140	722
Net Cost Impact (Base Carbon)	(NPV M 2011$) Disc. Rate = L	3,830	(61)	(55)	1,898	3,798	(75)	139	1,865

		Base PV Scenario				Indian Point			
Criteria	**Metric (units)**	**2013-2049**	**Thru 2017**	**Thru 2022**	**Thru 2032**	**2013-2049**	**Thru 2017**	**Thru 2022**	**Thru 2032**
	(NPV M 2011$) Disc. Rate = M	2,183	(45)	(46)	1,211	2,187	(56)	110	1,218
	(NPV M 2011$) Disc. Rate = H	825	(22)	(30)	540	858	(28)	75	575
Net Cost Impact (High Carbon)	(NPV M 2011$) Disc. Rate = L	(482)	(376)	(1,034)	(817)	242	(221)	(576)	(400)
	(NPV M 2011$) Disc. Rate = M	(590)	(326)	(855)	(749)	(80)	(184)	(471)	(393)
	(NPV M 2011$) Disc. Rate = H	(549)	(252)	(609)	(591)	(234)	(130)	(325)	(321)

Sensitivity Analysis: Indian Point

The Indian Point nuclear generating station was assumed to be retired in the reference case. A final sensitivity was conducted assuming continued operation of the Indian Point nuclear, to examine the impact on solar policies on direct rate impact and net cost of continued operation.

Figure 65 shows the results of this sensitivity analysis. In sum, the results show little or no sensitivity to the presence of Indian Point. There are some differences in terms of net costs, almost all of which is due to lower price suppression impacts through 2020 of the case with continued operation of Indian Point. Price suppression is expected to be higher (and net costs lower) without Indian Point because the generation mix to meet loads would necessarily include units that were not price takers (or as low down the bid stack as Indian Point). The figure shows that this is the case from 2018-2023. Following this period, price suppression is actually higher with continued operation of Indian Point though differences are small and are difficult to see (and are not differentiating factor) when comparing total net costs for the two cases as shown in Figure 65.

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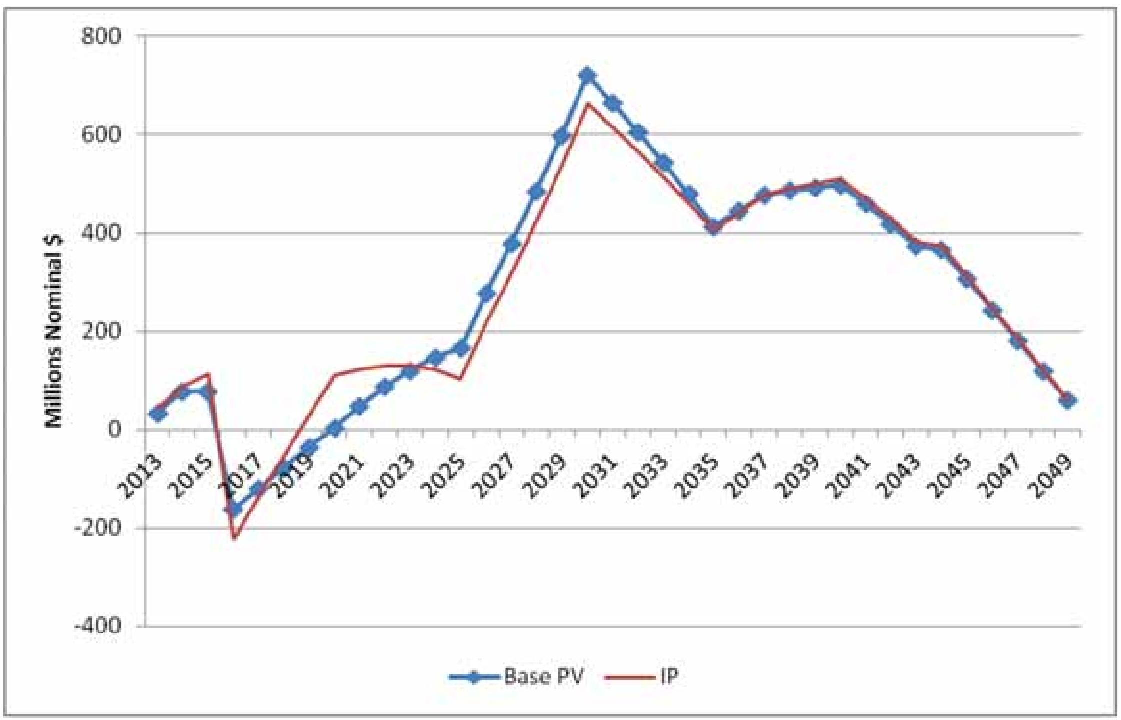

Figure 65. Net Costs, Base, Indian Point Sensitivity , 2013-2049

Table 142 shows the results for this sensitivity analyses. Overall, the presence of Indian Point has relatively small impacts compared to the base policy case that does not assumed continued operation of the generating facility.

Table 142. Environmental Impacts and Energy Costs, Base Policy vs. Indian Point Continued Operation, 2013-2049, NPV 2011$

Million 2011$	Base	Indian Point
Wholesale Price Suppression	(3,282)	(3,390)
Net Cost Impact (Low Carbon)	2,183	2,187

APPENDIX 7 – NET JOBS AND MACROECONOMIC IMPACT DETAILS (CH. 6)

A7.1. REMI Model Structure and Feedback Responses

Model Structure and Feedbacks

A REMI annual macroeconomic forecast for a region-of-impact allows for intervals of disequilibrium in the workings of an economy. As one example of the many interactions that may occur, the labor market might have slack that should reduce labor costs thereby making businesses substitute labor for capital where possible. This, in turn, should result in lowering a firm's cost-of-doing business, which should translate into a more price competitive output for that business and result in more sales (increased market share). More sales would require more labor, thereby diminishing labor slackness (in cycles) until equilibrium is restored. Many components of an economy may simultaneously be in disequilibria. The REMI forecast is a solution to resolve those episodes since the model's equation structure describes a computable general equilibrium ("CGE") system.

REMI represents the region's economy through five major blocks, within which key economic determinants are identified (see

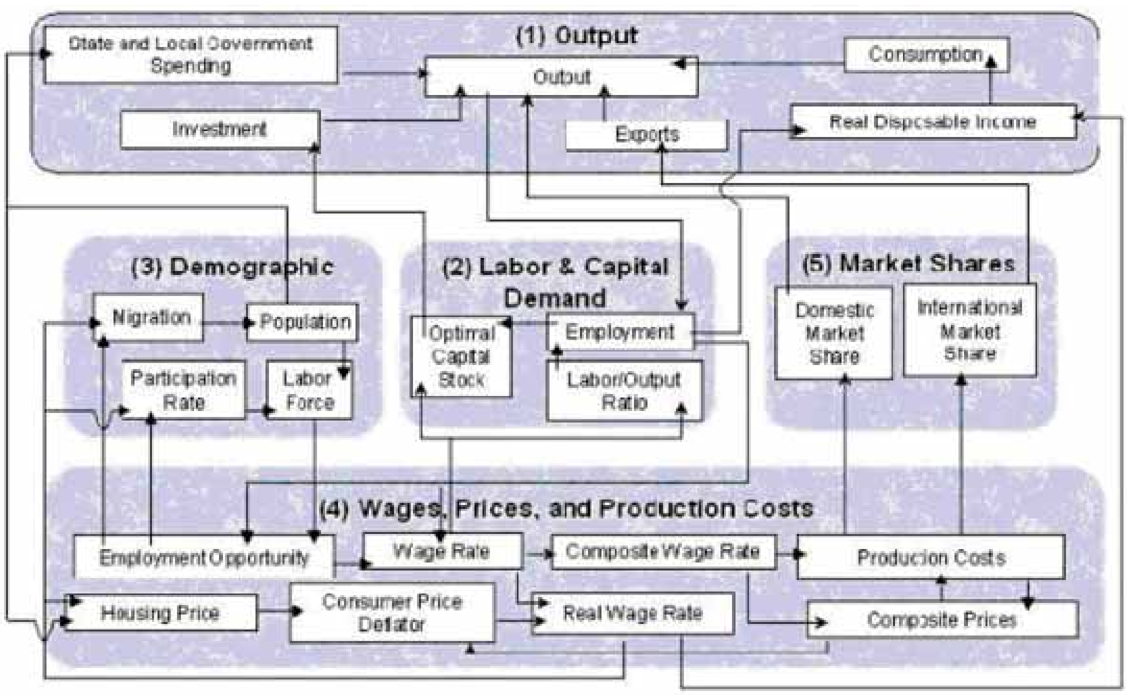

Figure 66). A diagram depicting the model's feedback system is shown in

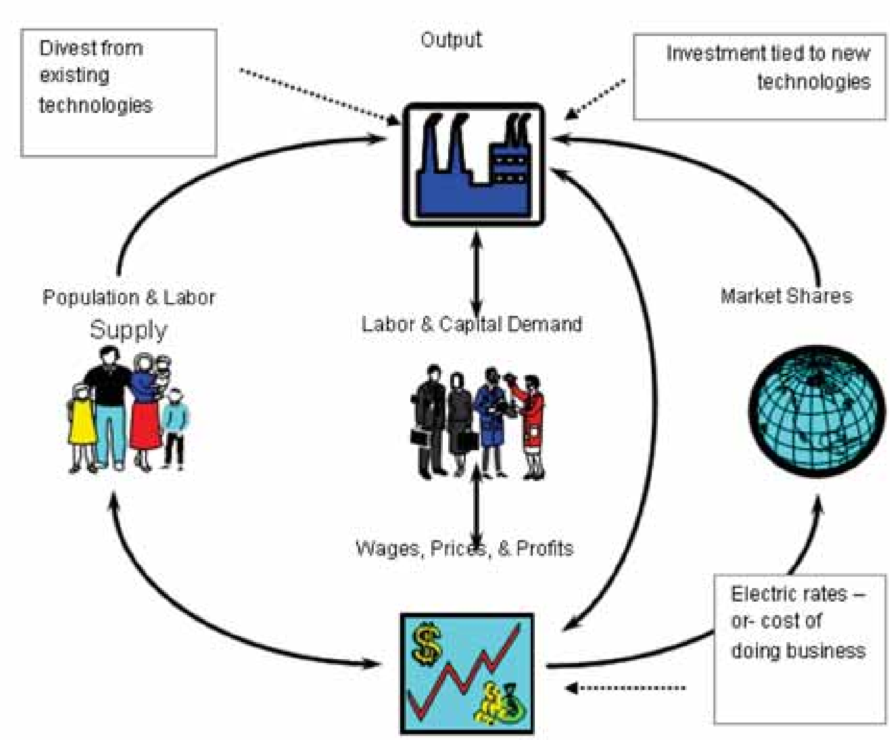

Figure 67. Unique to the REMI model among the class of other regional economic impact frameworks available is the linkage to the market shares block. Policies or investments that change the underlying cost-of-doing business for an industry in a region will affect that industry's relative competitiveness (relative to the U.S. average for that industry) and its ability to retain/gain sales within its own region, elsewhere in the U.S. and for international trade. The REMI model takes this into account when assessing economic impacts.

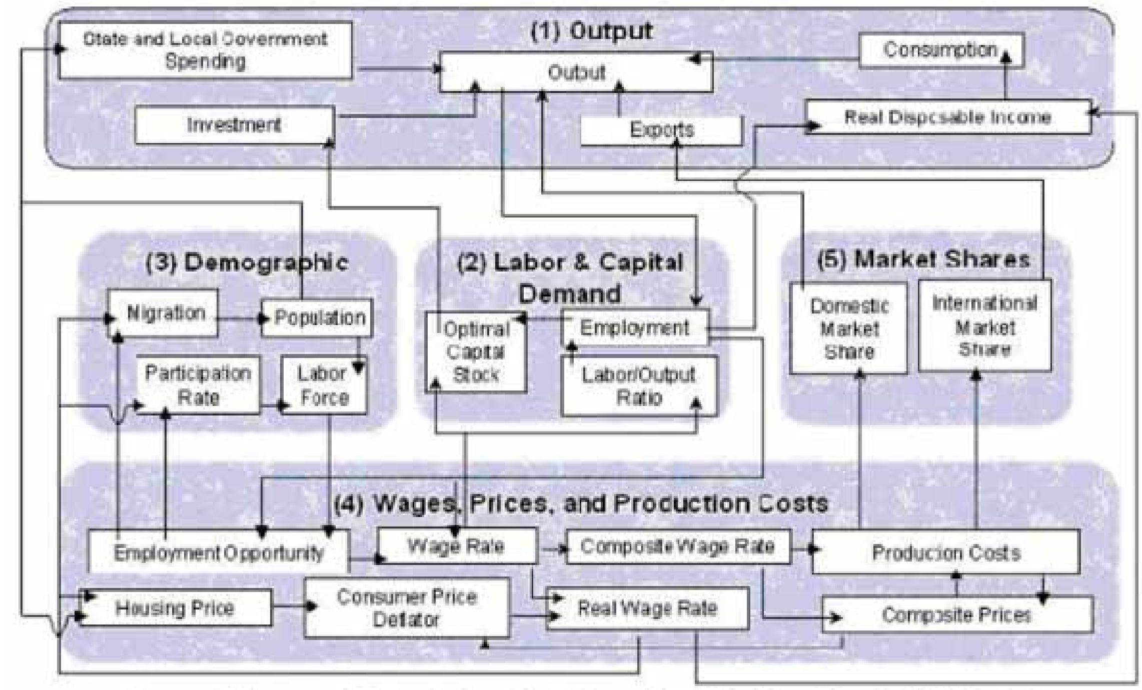

Figure 66. Internal Calculation Modules within the New York REMI Model (Source: Regional Economic Modeling, Inc.)

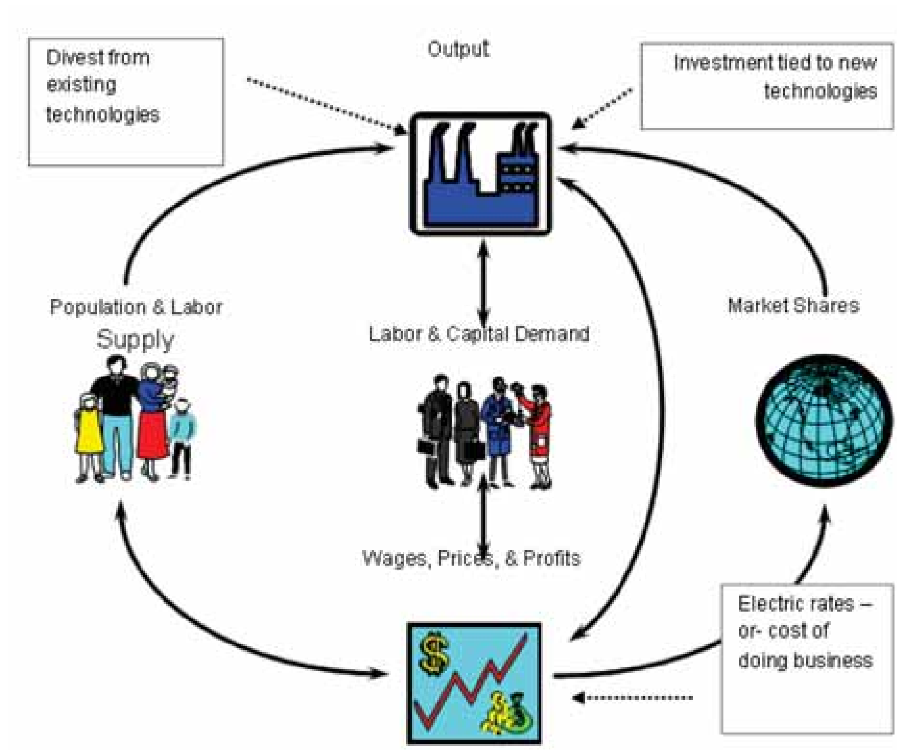

Figure 67. Simplified Portrayal of REMI Model Feedbacks (Source: Regional Economic Modeling, Inc.)

A7.2. Mapping Scenario Direct Effects into the REMI Model

"Mapping" Policy Direct Effects into REMI

The three categories of direct effect described above are given specific "input lever" assignments into the REMI model. Table 143 (positive effects) and Table 144 (Depressive effects) show the first level of assignment to "REMI equation concepts." A second assignment (Table 145 and Table 146) is required for some categories, such as investment demand changes and operations & maintenance spending changes, to provide detail on the types of industries that will be implicated in those dollar flows.

Table 143. Scenario's Positive Element Assignments to REMI Model levers

	ELEMENT	REMI Input Lever (assignment 1)	Detail Assignment 2?
POSITIVES			
	Increased demand for installation contractors	Construction labor compensation (70%); Construction other value-added (30%)	na
	Increased demand for PV equipment & components	change Industry OUTPUT for relevant subset of manufacturing NAICS	Y
	Increased demand for Financial Services	Industry OUTPUT for Monetary & Credit, Financing establishments	na
	Increased demand from annual O&M on PV systems	change in industry output for parts; and Construction labor	Y
	Reduced electric rates due to elec. Price Suppression effects (73%); avoided RPS payments; avoided Distribution system expansion	change in Consumer Purchasing Power	na
		change in Electricity Fuel Cost_Comm/ INDSTRL	na
		change in State Government spending	na

Table 144. Scenario's Depressive Element Assignments to REMI Model levers

	ELEMENT	REMI Input Lever (assignment 1)	Detail Assignment 2?
	Increase in Electric rates due to paying for incentives(the net solar premium)	change in Consumer Purchasing Power	na
		change in Electricity Fuel Cost_Comm/ INDSTRL	na
		change in State Government spending	na
	Reduced Capacity Investments on base case GEN assets	change in industry demand for sectors that contribute towards these investments	Y
	Reduced Purchases for Generators' Variable O&M requirements	change in intermediate demand for Utility sector (adjusting out fuel feedstocks)	na
	Reduced Purchases of Generators' Fuel Feedstocks	change in industry demand for Oil/Gas & Coal Mining activities; change in sales for NY Forestry & Logging firms for biomass feedstocks	na
	Reduced Profit income to NY shareholders' of NY Generating units (from price suppression)	reduced dividend, interest, & rental income in NY	na
	Reduced investment for Distribution System upgrades & expansion	reduced Construction labor compensation (15%); reduced demand for equipment & parts (85%)	na

There are two elements from Table 143 (PV equipment investment and PV system O&M expenditures) and one element from Table 144 (reduced investments for generating units across reference case technology types) for which additional input lever detail is needed for REMI. That extra detail involves identifying relevant industries providing the goods and services related to investment and O&M spending. Table 145 shows how annual O&M spending for PV will make its way through the New York economy.

Table 145. Residential* PV O&M Requirements (NREL, 2011c)

Budget item		Manuf. Cost	mark-up	NY industries
Materials & Parts	45%	0.43	0.20	Wholesale Trade
Labor	55%			Construction_Maint. & Repair
	100%			

* The shares related to small or large C/I systems and MW-scaled do differ and are modeled accordingly.

Table 146 provides detail on the composition of PV system investment cost. The allocation is taken from NYSERDA's PV Cost database (see Section 2.2). A 20% mark-up on cost of materials, based on historical industry data for Wholesale Trade establishments in New York (taken from NY IMPLAN database for 2009) is applied to the recent share of PV systems sold through the wholesale channel (approximately 24%) as tracked by USDOE EIA (U.S. EIA, 2009). This mark-up on annual system investment means that New York's wholesale trade sector captures some of the investment dollars even if just five percent of the manufactured content comes from New York firms.

Table 146. PV System Investment (Potential) Levers for REMI

PV System Investment allocation	Component	mark -up	Observed share by NY Mfg or Install firms	MFG Industries			
39%	module	5%	5%	Chemical Mfg	Plstc & Rubber prod. Mfg	Nonmetallic mineral Prod. Mfg	Comptr & Elec. Prod. Mfg
			Allocation =>	0.2	0.2	0.1	0.5
10%	inverter	5%	5%	Elec. Equip & Appli. Mfg			
13%	other equipment	5%	5%	Prim. Metal Mfg.	Fabr. Metal prod. Mfg	Comptr & Elec. Prod. Mfg	Elec. Equip & Appli. Mfg
				0.15	0.2	0.35	0.3
				NY Industries			
16%	site prep_install	na	95%	Construction_Maint. & Repair Resid.	Construction_Maint. & Repair Non-Resid.		
2%	11.9.1 other expense	na	100%				
	11.9.2 LEGAL			11.9.3 Legal Services			
	11.9.4 PERMITTING			11.9.5 State/local Gov. revenues			
	11.9.6 ENGRG			11.9.7 Prof. & Technical services			
20%	FINANCING		50%	11.9.8 Financial Services			
			24%	11.9.9 Wholesale Trade			

The detailed industry assignment of the future investment averted (as a result of PV capacity) for several types of existing electricity generating technologies occurring in New York is presented in Appendix 3. The information for translating IPM model generating technology investment changes[224] into changes for relevant capital good supplying industries was sourced from work developed by the Goodman Group on behalf of the MA DOER that mapped investment onto IMPLAN industries and for the RGGI REMI analysis (2006) IMPLAN industries were cross-walked to comparable REMI model sectors.

A7.3. Electric Generating Technology Investment Mapping

Table 147 presents generating technology sepcific investment requirements on the industries that provide the equipment and services to construct the generting unit. This information was developed by the Goodman Group (2003) on behalf of the MA DOER and mapped investment onto IMPLAN industries. The latter were cross-walked to comparable REMI model sectors for the RGGI REMI analysis (2006).

224 For combined cycle units, combustion turbine units, oil/gas-fired units, coal units, biomass units, and onshore wind farms.

Table 147. Electric Generating Technology Investment Mapping

IMPLAN codes (521-sector version)		CC	CT	(CC) Oil & Gas fired	Coal	Biomass Direct Fire	Landfill Gas	New Hydro	Onshore Wind	Offshore Wind	PV	REMI code
50	Construction -New Utility Structures	32.0%	61.3%	32.0%	58.6%			70.0%				Construction_industrial structures
56	Maintenance & Repair, Other Facilities					28.3%	28.3%		15.2%	20.0%	22.6%	Construction_Maintenance & Repair
219	Fabricated Rubber Products, NEC					13.0%	13.0%					Plastics & Rubber Prod. Mfg
220	Misc. Plastics Products					4.1%	4.1%					Plastics & Rubber Prod. Mfg
249	Asbestos Products				0.0%							Non-metallic Mineral prod. Mfg
258	Steel Pipe and Tubes				0.1%							Primary metal Mfg
267	Nonferrous Wire Drawing & Insulating	0.1%	0.4%	0.1%						0.8%		Electrical Equip. Mfg
282	Fabricated Structural Metal							4.0%	23.8%	28.0%	7.6%	Fabricated Metal Mfg
284	Fabricated Plate Work (Boiler Shops)	15.1%	5.9%	15.1%	14.2%							Fabricated Metal Mfg
303	Pipe, Valves, and Pipe Fittings		1.2%					3.0%				Fabricated Metal Mfg
307	Steam Engines and Turbines	47.3%	23.9%	47.3%	8.0%			18.0%	56.6%	46.6%		Machinery Mfg
315	Conveyors and Conveying Equipment				3.1%							Machinery Mfg
316	Hoists, Cranes, and Monorails	0.2%		0.2%	0.3%							Machinery Mfg
332	Pumps and Compressors	1.5%		1.5%	0.9%							Machinery Mfg
334	Blowers and Fans				11.2%	0.7%	0.7%					Machinery Mfg
338	General Industrial Machinery, NEC				0.2%	2.2%	2.2%					Machinery Mfg
349	Service Industry Machinery, NEC	0.1%	1.9%	0.1%	0.9%							Machinery Mfg
354	Industrial Machines, NEC				1.3%							Machinery Mfg
355	Transformers	0.9%	2.4%	0.9%								Electrical Equip. Mfg
356	Switchgear & Switchboard Apparatus	1.1%	2.9%	1.1%							3.9%	Electrical Equip. Mfg
357	Motors and Generators					33.7%	33.7%	2.5%				Electrical Equip. Mfg
360	Electrical Industrial Apparatus, NEC										19.6%	Electrical Equip. Mfg
372	Telephone & Telegraph Apparatus	0.2%		0.2%	0.0%							Computer & Electronics Mfg.
377	Semiconductors & Related Devices										42.3%	Computer & Electronics Mfg.
403	Mechanical Measuring Devices	1.1%		1.1%	0.9%							Computer & Electronics Mfg.
433	Railroads and Related Services	0.00%		0.00%	0.02%						0.02%	Rail transport
435	Motor Freight Transport & Warehousing	0.2%	0.1%	0.2%	0.1%	0.2%	0.2%		0.1%	0.1%	0.1%	Truck Transport
436	Water Transportation	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%			0.6%		Water Transport
437	Air Transportation	0.2%	0.1%	0.2%	0.1%	0.1%	0.1%		0.0%		0.1%	Air transport
447	Wholesale Trade					2.1%	2.1%		4.2%	4.0%	3.7%	Wholesale Trade
506	Engineering & Architectural Services					15.6%	15.6%	3.1%				Prof. & Technical Srvcs

A7.4. High Natural Gas Price Sensitivity Case – Inputs & Results

This sensitivity case varies both the IPM reference case and the Base PV Scenario by altering the underlying cost of natural gas (and hence electricity).

Scenario Inputs

The following information shown in Table 148 and Table 149 was derived in the course of the solar premium modeling analysis described in Chapter 5, and incorporates IPM model results described therein.

Table 148. High Gas Prices Full Deployment Scenario Positive Effects, Select Years and Cumulative through 2049 (M 2011$)

	Direct Effect	2013	2019	2025	2030	2040	2049	Cumulative
Positives	New Investment Demand PV	**560.0**	**1006.4**	**1095.7**	**0.0**	**0.0**	**0.0**	**12203.3**
	New O&M spending	**2.7**	**43.7**	**139.2**	**159.1**	**182.5**	**31.3**	**2358.8**
	Electric Price Suppression for ratepayers	**-10.8**	**-204.6**	**-459.2**	**-41.2**	**0.0**	**0.0**	**-4634.0**
	Residential	-3.6	-69.2	-155.4	-13.9	0.0	0.0	-1567.8
	Small C&I	-5.5	-105.6	-237.2	-21.2	0.0	0.0	-2389.9
	Large C&I	-1.4	-25.6	-57.5	-5.2	0.0	0.0	-583.3
	Government	-0.2	-4.1	-9.2	-0.8	0.0	0.0	-93.0
	Avoided RPS Payments to ratepayers	**-3.7**	**-12.7**	**-5.7**	**0.0**	**0.0**	**0.0**	**-130.7**
	Residential	-1.2	-4.3	-4.1	0.0	0.0	0.0	-50.8
	Small C&I	-1.9	-6.5	-1.2	0.0	0.0	0.0	-62.3
	Large C&I	-0.5	-1.6	-0.3	0.0	0.0	0.0	-15.2
	Government	-0.1	-0.3	0.0	0.0	0.0	0.0	-2.4
	Avoided Distribution System investment to ratepayers	**-2.4**	**-31.5**	**-81.0**	**-77.0**	**-56.7**	**-3.2**	**-1756.3**
	Residential	-0.8	-10.7	-27.4	-26.1	-19.2	-1.1	-594.2
	Small C&I	-1.2	-16.4	-42.2	-40.2	-29.6	-1.7	-915.9
	Large C&I	-0.3	-3.8	-9.7	-9.3	-6.8	-0.4	-210.9
	Government	0.0	-0.6	-1.6	-1.5	-1.1	-0.1	-35.3

Table 149. High Gas Prices Full Deployment Scenario Negative Effects, Select Years and Cumulative through 2049 (M 2011$)

	Direct Effect	2013	2019	2025	2030	2040	2049	Cumulative
DEPRESSIVE	Electric rate change (solar subsidy)	**44.7**	**380.0**	**648.5**	**496.4**	**244.6**	**18.0**	**12096.1**
	Residential	15.1	128.6	219.4	167.9	82.8	6.1	4092.5
	Small C&I	23.3	198.2	338.2	258.9	127.6	9.4	6307.9
	Large C&I	5.4	45.6	77.9	59.6	29.4	2.2	1452.9
	Government	0.9	7.6	13.0	10.0	4.9	0.4	242.8
	Future Generating Capacity divestment	**-87.5**	**-95.5**	**-118.8**	**3.1**	**0.3**	**0.2**	**-1244.4**
	Electric Utility O&M purchases	**0.0**	**-25.2**	**-31.9**	**-23.4**	**-13.8**	**-15.7**	**-696.0**
	Electric Utility Fuel purchases	**-3.6**	**-83.5**	**-159.8**	**-130.4**	**-200.2**	**-306.1**	**-5752.7**
	Reduced NY Generator Profits (Price Suppression)	**-0.5**	**-9.6**	**-21.6**	**-1.9**	**0.0**	**0.0**	**-218.0**
	Reduced Distribution System Expansion	**-2.4**	**-31.5**	**-81.0**	**-77.0**	**-56.7**	**-3.2**	**-1756.3**

Scenario Results

Table 150 presents aggregate macroeconomic impacts (as differences and as percent change from the New York reference case).

Table 150. Aggregate Impacts of the High Gas Price Full Deployment Scenario

Differences from Baseline Level								
Variable	**Units**	**2013**	**2019**	**2025**	**2030**	**2040**	**2049**	**NPV**
Total Employment	**(Jobs)**	1580	1102	733	-2965	-1042	-155	N/A
Gross State Product	**Billions of 2011$**	0.160	0.144	0.064	-0.521	-0.321	-0.114	-1.323
Output	**Billions of 2011$**	0.759	0.877	0.829	-0.839	-0.471	-0.198	-3.398
PCE-Price Index	**2005=100 (Nation)**	0.004	0.015	0.003	0.041	0.028	0.011	N/A
Real Disposable Personal Income	**Billions of 2011$**	0.318	0.432	0.526	-0.433	-0.249	-0.084	-2.213
Population	**People**	252	1137	111	-2691	-3326	-1602	N/A
Percent Change from Baseline Level								
Variable	**Units**	**2013**	**2019**	**2025**	**2030**	**2040**	**2049**	
Total Employment	**%**	0.013	-0.026	-0.063	-0.010	-0.002	-0.001	N/A
Gross State Product	**%**	0.011	0.005	-0.003	-0.020	-0.010	-0.004	N/A
Output	**%**	0.009	-0.001	-0.011	-0.018	-0.010	-0.005	N/A
PCE-Price Index	**%**	0.003	0.012	0.008	0.022	0.011	0.003	N/A
Real Disposable Personal Income	**%**	0.004	-0.012	-0.021	-0.034	-0.015	-0.003	N/A
Population	**%**	0.001	-0.014	-0.036	-0.031	-0.003	0.015	N/A

Annual macroeconomic impacts for the High Gas Cost Case are positive for jobs and dollars of GSP through 2025. This is the result foremost of solar investment activity handled by NY businesses, followed by the price suppression benefit, which after 2024 (when PV investment ceases as MW targets are met) will be the source of most positive job impacts through 2029. By 2030 it is the stimulus from annual solar O&M spending, and the ratepayers' avoided cost on distribution system upgrades that will create the most jobs. Other policy elements are responsible for exerting a more pronounced net negative effect on the NY economy from 2026 through 2049. Those elements include negative ratepayer effects, from the net cost of the solar policy, reduced investment in distribution system improvements, and reduced purchases for biomass fuel, and other variable operating expenses when existing generators operate at lower levels. As with all cases examined in Chapter 6, the price suppression benefit for ratepayers expires by 2039. Under this case, the IPM model shows modest additions for combustion turbine units from 2031 through 2049. For the entire analysis interval the New York economy will incur an average annual job impact of -506 jobs, and GSP impacts in NPV terms (at a real discount rate of 5.1 percent) worth -$1.3 billion over the 37 year interval.

The impacts on employment and GSP are decomposed by scenario effect Table 151) to provide a better understanding of how the mix of stimulative and depressive elements alters employment and GSP. Among the stimulative elements of the High Gas Cost Case the PV investment provides the largest stimulus to the economy for both jobs and dollars of GSP through 2025. Once the targeted level of solar PV capacity have been achieved (by 2025) the price suppression benefit to ratepayers will create the most jobs through 2029. The price suppression benefit tapers dramatically after 2028 and as a result its economic impact generation is comparable to the jobs and GSP created from the avoided distribution system investment costs (the remaining ratepayer benefit) and persistent solar PV O&M spending. The latter exerts modest but continual positive annual impacts on jobs and dollars of GSP.

Among the negative elements emanating from the High Gas Cost Case, the cost of the policy (i.e. the net solar subsidy cost) on ratepayers is the most pronounced of all depressive effects extending well through the 37 year interval. The lost investment demand for new generating capacity also causes the NY economy to shed jobs and dollars of GSP up through 2025 and then positive investment for CT units is expected and supports modest job gains. By 2024 it is the persistent reduction in biomass fuel purchases that becomes the second largest cause of economic loss in NY (for jobs and dollars of GSP) behind the ratepayers' burden of the net solar subsidy. The third source of job and GSP losses for NY is the deferral on distribution system improvements.

Table 151. Decomposed Employment & GSP Impacts of the High Gas Price Full Deployment Scenario

Total Employment	2013	2019	2025	2030	2040	2049	Avg. Annual Impact
Investment PV (installation & soft costs)	1897	2674	2611	-228	117	112	880
Investment NY Manufactured content	106	135	119	-18	-2	-3	39
Electricity Price Suppression all ratepayers	73	1693	3334	554	-176	-202	852
Avoided RPS payments (ratepayers)	25	107	96	-5	-11	-9	29
Avoided Ratepayer Payments for Distribution Expansion	17	231	588	556	317	-45	311
Increased Demand from PV O&M spending	22	217	524	445	318	27	293
Reduced Purchase of Other variable O&M	0	-119	-132	-87	-43	-44	-71
Increased Electric rates due to solar subsidy	-296	-2820	-4769	-3521	-1120	375	-2123
Decreased GEN Capacity Investments	-255	-304	-651	31	-12	-11	-159
Reduced Fuel Feedstock Purchase (Biomass, Coal, Oil/Gas)	-2	-574	-690	-458	-293	-355	-401
Reduced Distribution System Expansion	-8	-104	-228	-246	-144	-1	-139
Reduced Profits NY Generators (Price suppression)	-1	-35	-69	12	5	0	-16
Total	**1580**	**1102**	**733**	**-2965**	**-1042**	**-155**	**-506**
GSP (billion 2011$)	2013	2019	2025	2030	2040	2049	NPV
Investment PV (installation & soft costs)	0.188	0.274	0.266	-0.064	0.003	0.009	2.133
Investment NY Manufactured content	0.015	0.025	0.025	-0.002	0.000	0.000	0.199
Electricity Price Suppression all ratepayers	0.009	0.297	0.658	0.293	0.102	0.038	4.353
Avoided RPS payments (ratepayers)	0.003	0.020	0.022	0.006	0.002	0.001	0.182
Avoided Ratepayer Payments for Distribution Expansion	0.002	0.037	0.113	0.133	0.115	0.033	1.179
Increased Demand from PV O&M spending	0.002	0.019	0.046	0.038	0.026	-0.005	0.382
Reduced Purchase of Other variable O&M	0.000	0.001	0.002	0.003	0.001	0.001	0.023
Increased Electric rates due to solar subsidy	-0.035	-0.471	-0.969	-0.922	-0.558	-0.179	-9.108
Decreased GEN Capacity Investments	-0.023	-0.026	-0.056	0.013	0.001	0.001	-0.310
Reduced Fuel Feedstock Purchase (Biomass, Coal, Oil/Gas)	0.000	-0.019	-0.017	-0.005	-0.008	-0.016	-0.179
Reduced Distribution System Expansion	0.000	-0.008	-0.018	-0.016	-0.007	0.006	-0.147

Reduced Profits NY Generators (Price suppression)	0.000	-0.004	-0.007	0.004	0.001	-0.001	-0.029
Total	0.160	0.144	0.064	-0.521	-0.321	-0.114	-1.323

Figure 68 shows a comparison of the total job impacts between the Base PV Scenario and the High Gas Cost case. Given that the direct effects for the two cases shown in Table 38 and Table 39 are not that different, we would not expect dramatically different macroeconomic impacts to result.

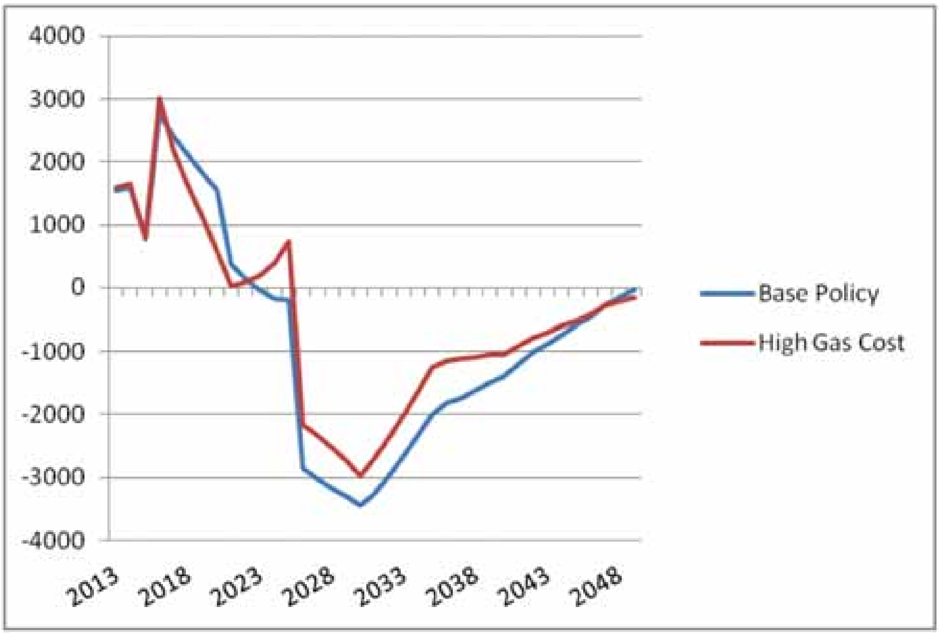

Figure 68. Total Jobs Impact Comparison Base PV Scenario and High Gas Cost cases

A7.5. Summary Results over Various Timeframes

Table 152. Base PV Scenario Macroeconomic Results

Criteria	Metric (units)	Study Period (2013-2049)	First 5 yrs (2013-2017)	First 10 yrs (2013-2022	First 20 yrs (2013-2032)
Net In-State Employment Impact	Job-Years	(27,653)	9,106	15,104	(7,285)
Net GSP Impact	(NPV M 2011$) Disc. Rate = L	(3,424)	778	1,130	(1,200)
	(NPV M 2011$) Disc. Rate = M	(1,634)	699	991	(513)
	(NPV M 2011$) Disc. Rate = H	(231)	578	785	101

Table 153. Low PV Cost Sensitivity

Criteria	Metric (units)	Study Period (2013-2049)	First 5 yrs (2013-2017)	First 10 yrs (2013-2022	First 20 yrs (2013-2032)
Net In-State Employment Impact	Job-Years	25,615	8,696	19,864	26,444
Net GSP Impact	(NPV M 2011$) Disc. Rate = L	2,782	790	1,780	2,584
	(NPV M 2011$) Disc. Rate = M	2,173	709	1,503	2,075
	(NPV M 2011$) Disc. Rate = H	1,454	584	1,116	1,426

Table 154. High PV Cost Sensitivity

Criteria	Metric (units)	Study Period (2013-2049)	First 5 yrs (2013-2017)	First 10 yrs (2013-2022	First 20 yrs (2013-2032)
Net In-State Employment Impact	Job-Years	(93,197)	9,519	9,046	(48,325)
Net GSP Impact	(NPV M 2011$) Disc. Rate = L	(11,208)	764	231	(5,998)
	(NPV M 2011$) Disc. Rate = M	(6,429)	689	283	(3,803)
	(NPV M 2011$) Disc. Rate = H	(2,369)	574	327	(1,593)

Table 155. High Natural Gas Cost Sensitivity

Criteria	Metric (units)	Study Period (2013-2049)	First 5 yrs (2013-2017)	First 10 yrs (2013-2022	First 20 yrs (2013-2032)
Net In-State Employment Impact	Job-Years	(18,735)	9,185	12,604	(3,839)
Net GSP Impact	(NPV M 2011$) Disc. Rate = L	(1,644)	851	1,165	(203)
	(NPV M 2011$) Disc. Rate = M	(568)	765	1,024	159
	(NPV M 2011$) Disc. Rate = H	222	632	815	437

APPENDIX 8 – RATE IMPACT ANALYSIS DETAILS (CH. 7)

A8.1. Methodology

Wholesale and Retail Cost Premiums

Policy options can support PV installations in two ways: (i) by providing additional sources of revenue (e.g. RPS/SREC, long-term contracting, feed-in tariffs, etc.); or (ii) by reducing the LCOE (e.g. grants, rebates, cash performance based incentives or state tax credits). For those policy options that provide an opportunity for additional sources of revenue the premium with be the difference between the LCOE and the market value of production. For policy options that reduce the LCOE the premium is the value of the incentive. For this analysis we employ the same methodology for all policy options.

The cost of PV deployment is based on the deployment schedules discussed in Chapter 4 and the costs discussed in Chapter 6 (along with variations driven by policy option-specific assumption from Chapter 10). Using these sets of data, the annual cost to install the target quantities of PV installations were developed for the various deployment scenarios, as well as the policy mechanisms discussed in Chapter 10. For the Base PV Scenario and each policy mechanism, we totaled the costs and wholesale market and retail avoided cost values up over the analysis horizon for the annual tranches of PV additions to yield the bottom line of cost premium.

Costs considered in projecting cost premiums include consideration of the direct cost of New York PV policy incentives, inclusive of federal incentives, participant investment cost, and any costs borne by ratepayer or taxpayers, including necessary administrative and transaction costs to implement the policy.

As the cost premium is measured relative to the market value of PV production, a basis for the market value is required. The IPM wholesale market value of PV results for each standard system size discussed in Section 5.2 form the basis of the wholesale PV premium for solar production sold to the grid. To estimate the retail solar policy premium for PV production consumed behind-the-meter, for each standard system size, the retail value of production is the retail value of avoided electric power purchases and delivery charges. The wholesale modeling results described in the prior section formed the basis for the forecast of the retail energy market value of solar energy production and capacity Historical utility tariffs for electricity supply charges (for each study region) were utilized to calculate a 2010 generation supply charge. A constant *retail adder* was calculated as the difference between average actual 2010 generation supply charges and the wholesale firm electricity values. The retail adder, which represents other components of retail supply costs not captured in the wholesale firm electricity price, such as ancillary services, NYISO charges, and delivery losses, was added to each year's market value of PV for the study period to calculate annual generation supply charges avoided for each region and for customer sizes corresponding to the project size categories described above.[225]

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225 This simplified approach assumes that the retail adder was fixed in nominal terms throughout the study period.

Administrative costs, based on assumptions discussed in Chapter 10, were also added to the cost of the policies.[226]

Above-Market Costs: Upfront Incentive

A Standard Offer Upfront Incentive payment is assumed to be available to residential and small commercial customers under one of the hybrid policies discussed in Section 10.4. The magnitude of the upfront incentive payment, in $\$/W_{DC}$ for each standard installation size, location and installation year, was calculated as the net present value of above-market costs, discounted at the investor's assumed cost of equity, as follows:

- Above market costs represent the difference between the Base LCOE (see Section 3.8) and the market value of production
- For Residential systems, the market value of production was the retail electricity payments avoided due to PV production. For Small C&I systems, the market value of production was weighted 90% by the retail electricity payments avoided due to PV production, and 10% by the wholesale energy and capacity revenue representing sales to the grid
- The difference between LCOE and market value over 25 years from the year of installation was calculated in each year in $/MWh, and multiplied by the assumed production to derive the total dollars of annual above-market costs
- This total stream of annual above-market costs was discounted to the year of installation, and divided by the standard installation size to yield a $\$/W_{DC}$ up-front incentive
- The discount rate of 12% represents the investors' assumed cost of equity, as discussed in Section 3.6. At this rate, the investor should be indifferent to an up-front payment or a long-term fixed revenue stream. Because the investor discount rate exceeds typical consumer discount rates), all else equal, an upfront incentive may therefore look less costly from a ratepayer or societal net present value perspective despite the front-loaded policy cost.

The total annual cost of the upfront incentive is calculated as follows:

$$Total\ Annual\ Upfront\ Incentive\ Cost = \left[\sum_{a=1}^{n} MW_a \times UI_a\right] + Admin\ Cost$$

Where:

a = each standard size and location combination

UI_a = the upfront incentive payment for the size and location combination *a* calculated as described above.

226 Transaction costs are not included in the generic base policy. As discussed in Section 10.4.2.3, deriving transaction costs relating to the solar policy is beyond the scope of this study.

Direct policy incentive costs of upfront incentives are incurred in each year 2013 through 2025, the years in which installations occur.

Above-Market Costs: Performance-Based Incentive Approaches

In contrast to upfront incentives, performance-based incentives (PBI), discussed in detail in Chapter 9 are paid over time.[227] The total annual cost premium, or direct rate impact, of a PBI in each year *for PV installed in each year* is calculated as follows:

$$Total\ Annual\ Incentive\ Cost = \left(\left\lfloor \sum_{a=1,b=1}^{n} MWh\_BTM_{a,b} \times \left\{LCOE_{a,b} - Mkt\_Val\_Retail_a\right\} \right\rfloor + \left\lfloor \sum_{a=1,b=1}^{n} MWh\_Grid_{a,b} \times \left\{LCOE_{a,b} - Mkt\_Val\_WS_a\right\} \right\rfloor\right) + Admin\ Cost$$

Where:

a = each standard size and location combination;

b = year of installation;

$MWh\_BTM_{a,b}$ = MWh PV consumed behind-the-meter;

$MWh\_Grid_{a,b}$ = MWh PV sold to the grid;

$LCOE_{a,b}$ = LCOE in $/MWh for size and location *a*, for PV systems installed in year *b*;

$Mkt\_Val\_Retail_a$ = the Retail avoided power and delivery charges for size and location combination *a*.

$Mkt\_Val\_WS_a$ = the wholesale revenue for size and location combination *a* adjusted for losses.

The first set of bracketed terms (within parenthetical brackets) represents the retail premium and the second set of terms represents the wholesale premium. Administrative costs (where applicable for each relevant policy) are then added[228] to these premiums.

Projection of the retail market value was built up by assessing the components of retail electricity costs. The generation supply charge component was first computed, as described above. The avoided delivery charge components of retail rates were estimated, as the current utility delivery charges trended over time with inflation. For this analysis, a representative retail rate was selected for each of the geographic regions and for each project size

227 The LCOEs derived in Chapter 3 implicitly spread fixed costs over a 25 year assumed life of a PV installation.

228 Administrative costs are a fixed percentage of the sum of wholesale and retail premiums.

category. The wholesale premiums are calculated by summing the total cost of PV for all cumulative installations in each year of the study period and subtracting the wholesale energy and capacity values for the solar energy and capacity production in each year (adjusted for avoided losses due to the assumption that energy and capacity generated by the solar facilities will be consumed on-site or nearby).

A8.2. Methodology

Table 156. Net Rate Impact Components, Base Policy, 2013-2049 (Million $, Nominal)

	Retail Premium BTM	Wholesale Premium	Direct Ratepayer Impact	Net Metering Impact	Price Suppression	Net Ratepayer Impact		Retail Premium BTM	Wholesale Premium	Direct Ratepayer Impact	Net Metering Impact	Price Suppression	Net Ratepayer Impact
2013	22.5	15.0	37.5	7.1	-3.0	41.5	**2032**	251.8	268.7	520.5	358.3	-73.1	805.7
2014	47.7	30.0	77.7	16.4	-1.5	92.6	**2033**	238.8	261.8	500.6	363.4	-108.7	755.3
2015	73.8	47.8	121.7	28.2	-40.1	109.7	**2034**	225.8	254.8	480.5	368.7	-146.1	703.1
2016	109.2	72.7	181.9	44.2	-359.5	-133.4	**2035**	212.9	247.7	460.6	374.1	-185.4	649.2
2017	140.8	96.4	237.2	63.0	-384.4	-84.2	**2036**	200.9	244.8	445.8	378.9	-148.9	675.9
2018	172.3	120.9	293.1	84.6	-410.1	-32.4	**2037**	189.3	242.0	431.3	383.8	-112.0	703.1
2019	202.3	145.6	347.9	109.1	-436.8	20.2	**2038**	170.5	231.6	402.0	378.8	-74.9	705.9
2020	229.7	170.0	399.7	136.8	-464.3	72.1	**2039**	152.2	219.8	372.0	370.6	-37.6	705.0
2021	263.1	200.3	463.4	168.0	-503.9	127.5	**2040**	135.3	207.2	342.5	359.2	0.0	701.7
2022	292.1	230.2	522.2	202.3	-544.1	180.4	**2041**	118.3	192.4	310.7	341.8	0.0	652.6
2023	315.3	259.2	574.5	240.1	-586.3	228.3	**2042**	100.9	176.0	277.0	320.9	0.0	597.9
2024	332.9	287.3	620.2	281.4	-629.9	271.7	**2043**	83.5	158.0	241.5	296.2	0.0	537.7
2025	345.7	314.1	659.8	326.1	-675.5	310.3	**2044**	66.5	138.4	204.9	267.5	0.0	472.4
2026	330.1	307.9	638.1	330.3	-554.9	413.4	**2045**	50.2	117.4	167.5	234.8	0.0	402.3
2027	314.5	301.4	615.9	334.9	-428.4	522.4	**2046**	34.2	94.2	128.3	197.0	0.0	325.3
2028	301.2	295.0	596.2	339.4	-295.0	640.6	**2047**	21.5	70.8	92.4	154.9	0.0	247.3
2029	288.9	288.4	577.4	344.1	-154.6	766.8	**2048**	11.9	47.4	59.3	108.0	0.0	167.3
2030	277.6	282.1	559.7	348.5	-7.0	901.2	**2049**	4.7	23.8	28.5	56.3	0.0	84.8
2031	264.8	275.4	540.3	353.3	-39.2	854.4							

Table 157. Direct and Net Ratepayer Impact, Base PV Scenario, High PV Cost, Low PV Cost, Total and % of Bill, NPV $2011

		Discount Rate	Base PV Scenario				High Cost Future				Low Cost Future			
			2013-2049	Thru 2017	Thru 2022	Thru 2032	2013-2049	Thru 2017	Thru 2022	Thru 2032	2013-2049	Thru 2017	Thru 2022	Thru 2032
Direct Ratepayer Impact	(NPV M 2011$)	4.35%	6,424	536	1,903	4,867	14,641	790	3,468	10,346	1,783	321	1,581	870
	(NPV M 2011$)	6.99%	4,356	477	1,564	3,555	9,628	701	2,827	7,433	1,462	286	1,207	725
	(NPV M 2011$)	11.98%	2,323	386	1,104	2,079	4,869	565	1,964	4,209	974	232	765	525
Total Revenue	(NPV M 2011$)	4.35%	553,005	96,152	182,839	337,168	553,005	96,152	182,839	337,168	553,005	96,152	337,168	182,839
	(NPV M 2011$)	6.99%	363,034	87,178	156,506	259,262	363,034	87,178	156,506	259,262	363,034	87,178	259,262	156,506
	(NPV M 2011$)	11.98%	197,286	73,141	119,406	168,976	197,286	73,141	119,406	168,976	197,286	73,141	168,976	119,406
Ratepayer Impact as a percent of Total Revenue	% of total rates, Disc. Rate = L	4.35%	1.2%	0.6%	1.0%	1.4%	2.6%	0.8%	1.9%	3.1%	0.3%	0.3%	0.5%	0.5%
	% of total rates, Disc. Rate = M	6.99%	1.2%	0.5%	1.0%	1.4%	2.7%	0.8%	1.8%	2.9%	0.4%	0.3%	0.5%	0.5%
	% of total rates, Disc. Rate = H	11.98%	1.2%	0.5%	0.9%	1.2%	2.5%	0.8%	1.6%	2.5%	0.5%	0.3%	0.5%	0.4%
Net Ratepayer Impact	(NPV M 2011$)	4.35%	5,753	39	275	2,984	13,970	293	1,840	8,463	1,111	-176	-759	-302
	(NPV M 2011$)	6.99%	3,382	44	226	1,984	8,655	269	1,489	5,862	340	-147	-613	-364
	(NPV M 2011$)	11.98%	1,384	50	163	971	3,930	230	1,023	3,101	-140	-104	-416	-343

		Discount Rate	Base PV Scenario				High Cost Future				Low Cost Future			
			2013-2049	Thru 2017	Thru 2022	Thru 2032	2013-2049	Thru 2017	Thru 2022	Thru 2032	2013-2049	Thru 2017	Thru 2022	Thru 2032
Ratepayer Impact as a percent of Total Revenue	% of total rates, Disc. Rate = L	4.35%	1.0%	0.0%	0.2%	0.9%	2.5%	0.3%	1.0%	2.5%	0.2%	-0.2%	-0.2%	-0.2%
	% of total rates, Disc. Rate = M	6.99%	0.9%	0.1%	0.1%	0.8%	2.4%	0.3%	1.0%	2.3%	0.1%	-0.2%	-0.2%	-0.2%
	% of total rates, Disc. Rate = H	11.98%	0.7%	0.1%	0.1%	0.6%	2.0%	0.3%	0.9%	1.8%	-0.1%	-0.1%	-0.2%	-0.3%

Table 158. Direct and Net Ratepayer Impact, Base PV Scenario, Alt-A, and Alt-B Deployments, Total and % of Bill, NPV $2011

			Base PV Scenario				Alt-A Deployment				Alt-B Deployment			
		Discount Rate	2013-2049	Thru 2017	Thru 2022	Thru 2032	2013-2049	Thru 2017	Thru 2022	Thru 2032	2013-2049	Thru 2017	Thru 2022	Thru 2032
Direct Ratepayer Impact	(NPV M 2011$)	4.35%	6,424	536	1,903	4,867	5,735	513	1,784	4,400	7,452	563	2,047	5,495
	(NPV M 2011$)	6.99%	4,356	477	1,564	3,555	3,913	456	1,468	3,227	4,996	501	1,680	3,993
	(NPV M 2011$)	11.98%	2,323	386	1,104	2,079	2,110	370	1,038	1,902	2,617	405	1,183	2,314
Total Revenue	(NPV M 2011$)	4.35%	553,005	96,152	182,839	337,168	553,005	96,152	337,168	182,839	553,005	96,152	182,839	337,168
	(NPV M 2011$)	6.99%	363,034	87,178	156,506	259,262	363,034	87,178	259,262	156,506	363,034	87,178	156,506	259,262
	(NPV M 2011$)	11.98%	197,286	73,141	119,406	168,976	197,286	73,141	168,976	119,406	197,286	73,141	119,406	168,976
Ratepayer Impact as a percent of Total Revenue	% of total rates, Disc. Rate = L	4.35%	1.2%	0.6%	1.0%	1.4%	1.0%	0.5%	0.5%	2.4%	1.3%	0.6%	1.1%	1.6%
	% of total rates, Disc. Rate = M	6.99%	1.2%	0.5%	1.0%	1.4%	1.1%	0.5%	0.6%	2.1%	1.4%	0.6%	1.1%	1.5%
	% of total rates, Disc. Rate = H	11.98%	1.2%	0.5%	0.9%	1.2%	1.1%	0.5%	0.6%	1.6%	1.3%	0.6%	1.0%	1.4%
Net Ratepayer Impact	(NPV M 2011$)	4.35%	5,753	39	275	2,984	4,450	-157	-321	1,851	7,907	165	1,340	5,259
	(NPV M 2011$)	6.99%	3,382	44	226	1,984	2,433	-129	-266	1,126	5,017	155	1,082	3,684
	(NPV M 2011$)	11.98%	1,384	50	163	971	820	-87	-187	437	2,379	138	741	1,989

Ratepayer Impact as a percent of Total Revenue	% of total rates, Disc. Rate = L	4.35%	1.0%	0.0%	0.2%	0.9%	0.8%	-0.2%	-0.1%	1.0%	1.4%	0.2%	0.7%	1.6%
	% of total rates, Disc. Rate = M	6.99%	0.9%	0.1%	0.1%	0.8%	0.7%	-0.1%	-0.1%	0.7%	1.4%	0.2%	0.7%	1.4%
	% of total rates, Disc. Rate = H	11.98%	0.7%	0.1%	0.1%	0.6%	0.4%	-0.1%	-0.1%	0.4%	1.2%	0.2%	0.6%	1.2%

Table 159. Direct and Net Ratepayer Impact, Base PV Scenario, High NG, Total and % of Bill, NPV $2011

			Base PV Scenario				High Natural Gas Sensitivity			
		Discount Rate	2013-2049	Thru 2017	Thru 2022	Thru 2032	2013-2049	Thru 2017	Thru 2022	Thru 2032
Direct Ratepayer Impact	(NPV M 2011$)	4.35%	6,424	536	1,903	4,867	5,448	498	1,739	4,267
	(NPV M 2011$)	6.99%	4,356	477	1,564	3,555	3,741	443	1,430	3,130
	(NPV M 2011$)	11.98%	2,323	386	1,104	2,079	2,033	359	1,011	1,845
Total Revenue	(NPV M 2011$)	4.35%	553,005	96,152	182,839	337,168	605,145	102,667	195,551	363,695
	(NPV M 2011$)	6.99%	363,034	87,178	156,506	259,262	395,206	93,057	167,338	279,291
	(NPV M 2011$)	11.98%	197,286	73,141	119,406	168,976	213,142	78,031	127,596	181,601
Ratepayer Impact as a percent of Total Revenue	% of total rates, Disc. Rate = L	4.35%	1.2%	0.6%	1.0%	1.4%	0.9%	0.5%	0.9%	1.2%
	% of total rates, Disc. Rate = M	6.99%	1.2%	0.5%	1.0%	1.4%	0.9%	0.5%	0.9%	1.1%
	% of total rates, Disc. Rate = H	11.98%	1.2%	0.5%	0.9%	1.2%	1.0%	0.5%	0.8%	1.0%
Net Ratepayer Impact	(NPV M 2011$)	4.35%	5,753	39	275	2,984	4,136	-59	315	1,934
	(NPV M 2011$)	6.99%	3,382	44	226	1,984	2,379	-45	250	1,274

		Discount Rate	Base PV Scenario 2013-2049	Base PV Scenario Thru 2017	Base PV Scenario Thru 2022	Base PV Scenario Thru 2032	High Natural Gas Sensitivity 2013-2049	High Natural Gas Sensitivity Thru 2017	High Natural Gas Sensitivity Thru 2022	High Natural Gas Sensitivity Thru 2032
	(NPV M 2011$)	11.98%	1,384	50	163	971	936	-26	166	615
Ratepayer Impact as a percent of Total Revenue	% of total rates, Disc. Rate = L	4.35%	1.0%	0.0%	0.2%	0.9%	0.7%	-0.1%	0.2%	0.5%
	% of total rates, Disc. Rate = M	6.99%	0.9%	0.1%	0.1%	0.8%	0.6%	0.0%	0.1%	0.5%
	% of total rates, Disc. Rate = H	11.98%	0.7%	0.1%	0.1%	0.6%	0.4%	0.0%	0.1%	0.3%

Table 160. Direct and Net Ratepayer Impact, Base PV Scenario vs. Indian Point, Total and % of Bill, NPV $2011

			Base PV Scenario				Indian Point Continued Operation Sensitivity			
		Discount Rate	2013-2049	Thru 2017	Thru 2022	Thru 2032	2013-2049	Thru 2017	Thru 2022	Thru 2032
Direct Ratepayer Impact	(NPV M 2011$)	4.35%	6,424	536	1,903	4,867	6,460	545	1,925	4,899
	(NPV M 2011$)	6.99%	4,356	477	1,564	3,555	4,383	484	1,582	3,580
	(NPV M 2011$)	11.98%	2,323	386	1,104	2,079	2,340	392	1,117	2,096
Total Revenue	(NPV M 2011$)	4.35%	553,005	96,152	182,839	337,168	553,005	96,152	182,839	337,168
	(NPV M 2011$)	6.99%	363,034	87,178	156,506	259,262	363,034	87,178	156,506	259,262
	(NPV M 2011$)	11.98%	197,286	73,141	119,406	168,976	197,286	73,141	119,406	168,976
Ratepayer Impact as a percent of Total Revenue	% of total rates, Disc. Rate = L	4.35%	1.2%	0.6%	1.0%	1.4%	1.2%	0.6%	1.1%	1.5%
	% of total rates, Disc. Rate = M	6.99%	1.2%	0.5%	1.0%	1.4%	1.2%	0.6%	1.0%	1.4%
	% of total rates, Disc. Rate = H	11.98%	1.2%	0.5%	0.9%	1.2%	1.2%	0.5%	0.9%	1.2%
Net Ratepayer Impact	(NPV M 2011$)	4.35%	5,753	39	275	2,984	5,689	1	446	2,940
	(NPV M 2011$)	6.99%	3,382	44	226	1,984	3,364	12	360	1,978

		Discount Rate	Base PV Scenario				Indian Point Continued Operation Sensitivity			
			2013-2049	Thru 2017	Thru 2022	Thru 2032	2013-2049	Thru 2017	Thru 2022	Thru 2032
	(NPV M 2011$)	11.98%	1,384	50	163	971	1,400	27	249	993
Ratepayer Impact as a percent of Total Revenue	% of total rates, Disc. Rate = L	4.35%	1.0%	0.0%	0.2%	0.9%	1.0%	0.0%	0.2%	0.9%
	% of total rates, Disc. Rate = M	6.99%	0.9%	0.1%	0.1%	0.8%	0.9%	0.0%	0.2%	0.8%
	% of total rates, Disc. Rate = H	11.98%	0.7%	0.1%	0.1%	0.6%	0.7%	0.0%	0.2%	0.6%

A8.3. Sensitivity Analysis: Indian Point

The Indian Point nuclear generating station was assumed to be retired in the reference case. A final sensitivity was conducted assuming continued operation of the Indian Point nuclear, to examine the impact on solar policies on net rate impact.

Figure 69 shows the results of this sensitivity analysis. In sum, the results show little or no sensitivity to the presence of Indian Point. Direct rate impacts are almost identical as wholesale and retail generation rates show little change between the two cases.

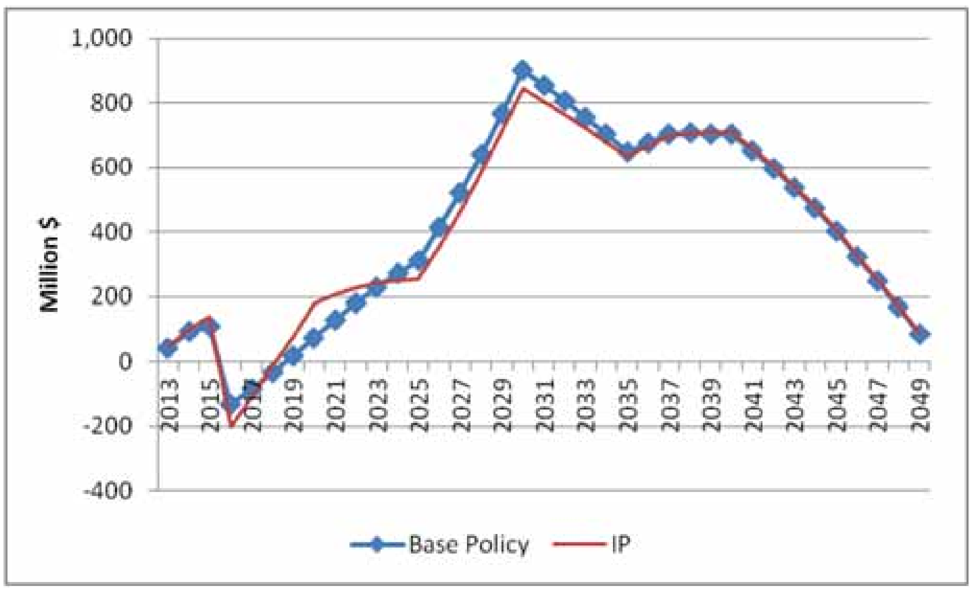

Figure 69. Net Rate Impact, Base, Indian Point, 2013-2049

APPENDIX 9 – PV DEPLOYMENT SCENARIO DEVELOPMENT

A9.1 Introduction

This appendix explains the methodology, key assumptions, inputs and results of the PV deployment scenario cases. Section A9.2 describes the approach used to develop PV deployment scenarios, along with some key assumptions. In Section A9.3, the development of standard PV system sizes is described. Section A9.4 described the derivation and assumptions for the reference case. The base deployment scenario assumptions are described in Section A9.5, while the alternative deployment scenarios are described in Section A9.6. Finally, each of the PV policy deployment scenarios is summarized for 2015, 2020 and 2025 in Section A9.7.

A9.2 Methodology and Key Assumptions

Deployment scenarios were developed by first establishing assumptions for targets and trajectories to reach those targets, and then deriving assumptions for proportions of those targets that fall into different installation size, financial compensation configurations (either behind-the-meter or wholesale power), and geographic location categories. For all cases, the projected PV capacity increases annually until 2025.

In addition, it was assumed that the choice of PV incentive policy mechanism did not, by itself, alter the capacity target, trajectory to reach that target, or distribution of installations of PV installations. It is conceivable, and perhaps likely, that different policies could result in different rates of uptake or distribution among installations types, sizes or locations. Still, as discussed in Chapter 10, policy mechanisms can be designed to have similar, or different, deployment distributions. In order to isolate impacts of the choice of policy from the choices made in policy design details, the policies modeled are assumed to be designed to yield similar distributions. Then, two alternative deployment scenarios were developed in order to test the sensitivity of the study's results to design choices that might favor different distributions.

The MW capacity described throughout this chapter represent the average MW in operation during a calendar year. As installations are typically put into operation throughout the year, the actual MW installed will be less than a specific year's annual average at the beginning of the year, and the MW installed by year end will exceed the annual average.

Targets and Trajectories

The proposed targets established by the Act include 2,500 MW by 2020 and 5,000 MW by 2025. To reach these targets, it is assumed that the PV policy drives incremental PV solar capacity from the Reference Case up to the total indicated (i.e. the difference between the annual target and the Reference Case is the increment driven by the PV policy).

A trajectory of annual targets for PV installations over time was then established to transition from the current level of installations described in Chapter 1.3 to reach the Full and Partial Targets, respectively. Applying a second-order polynomial equation yielded the trajectories shown in Table 161 and Figure 70. This approach approximates a smooth market growth that takes advantage of expected future PV price declines both from global component cost reductions and improved market conditions in New York.

Table 161: Deployment Targets and Trajectories

Year	Reference Case (MW_{DC})	Policy Target Trajectory (MW_{DC})	Total PV Target Best Fit (MW_{DC})		Reference Case (GWh)	Policy Target Trajectory (GWh)	Total PV Target Best Fit (GWh)
2011	144		144		172	0	172
2012	274	0	274		323	0	323
2013	310	122	432		361	164	525
2014	346	279	625		400	327	727
2015	382	471	853		444	549	993
2016	388	725	1114		448	842	1290
2017	395	1014	1409		453	1232	1686
2018	402	1337	1739		459	1623	2081
2019	408	1694	2102		464	2013	2477
2020	415	2085	2500		470	2403	2873
2021	415	2517	2932		468	2969	3437
2022	415	2983	3398		465	3535	4000
2023	415	3483	3898		463	4101	4564
2024	415	4017	4432		460	4668	5128
2025	415	4585	5000		458	5234	5692

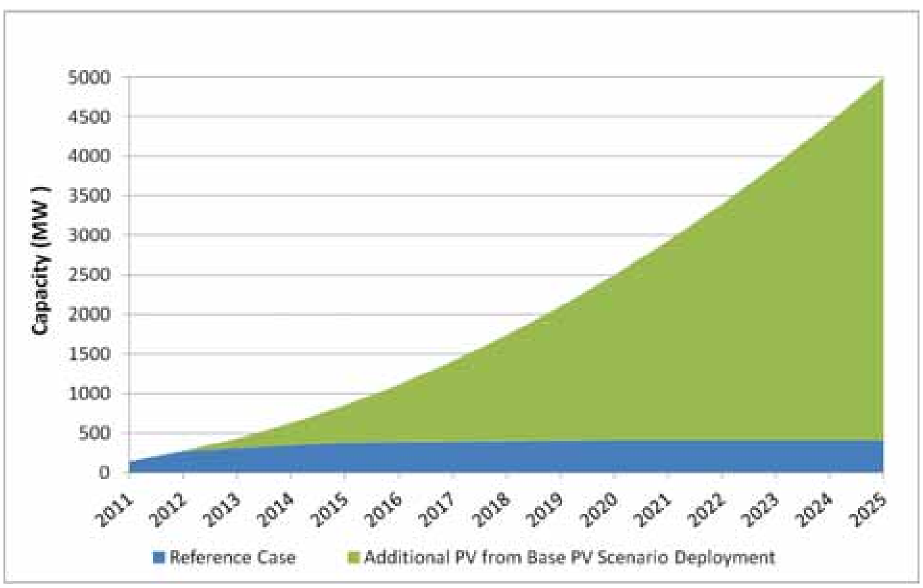

Figure 70. PV Policy Trajectory

Aggregated Geographic Regions

Installations within each of the eleven NYISO load zones were assigned to five aggregated geographic regions. The aggregation of NYISO load zones was based on criteria including (i) minimizing the number of zones to differentially model; (ii) locational marginal pricing (LMP) similarity, (iii) similarity of population density, land topography and land use characteristics. The aggregated regions were defined as shown in Table 162 and Figure 71, and held constant in all scenarios.

Table 162. Aggregate Load Zones Used in this Analysis

REGION	NYISO ZONES
Upstate	A, B, C, D, E
Capital	F
Hudson Valley	G, H, I
New York City	J
Long Island	K

Figure 71. Aggregate Load Zones Used in this Analysis

Reference Case

For the reference case, existing NYSERDA, LIPA and NYPA solar policies were projected until their sunset. Most of these policies are currently set to sunset well before 2025. It was assumed that no further PV installations would occur in the state after these programs expire. The reference case also catalogs the state's existing PV fleet. Information for the reference case was developed in consultation with NYSERDA, LIPA and NYPA to fully account for existing installations and future program implementation. Further details on the assumptions in the reference case are found in Section A9.4.

Installation Size and Financial Compensation Distributions

In order to effectively model a broad and continuous range of system sizes, standard system sizes were defined for each of four classes of installations: (i) residential, (ii) small commercial, (iii) larger commercial, and (iv) megawatt-scale. The characteristics of the four standard sizes represent the *average* characteristics of installations within each of four classes of installation which, together, are assumed to span the spectrum of PV installations expected in response to policy incentives. For each standard installation size, an assumption was also developed for the proportion of production that (i) *financially*[229] displaces retail electricity purchases and whose value is therefore approximated by the value of retail electricity purchases avoided; and (ii) is delivered to the wholesale grid and sold on the wholesale electricity market.[230]

Future deployment is expected to differ from past deployment in New York for a few reasons, including:

- Size limitations of past programs. Current NYSERDA CST rebates are limited to installations under 100 kW. No such limitation is assumed to apply to programs seeking to reach a 5000 MW goal
- Different programs and incentives apply in different territories. For purposes of this study, a uniform policy approach to supporting solar energy was assumed to apply statewide, consistent with enabling legislation adopted with an eye towards equitable distribution of policy costs in alignment with a set of broadly shared benefits. This approach contrasts with New York's current renewable energy policies which differ between investor-owned utility territories and publicly-owned utility territories
- Early adopters. Participants in future programs are likely to differ from early adopters participating in past programs. Typical early adopters tend to be more affluent, have large homes, and/or exhibit a willingness to pay a green premium (this not needing a rebate to cover the full over-market cost). As prices decline and penetrations must rise to meet a 5000 MW goal, it is expected that deployment will penetrate different market segments with different characteristics.

229 This concept is defined broadly to include both production consumed on-site by a host of a PV installation interconnected behind a retail meter, as well as any production treated as if consumed on-site under net metering or virtual net metering policies.

230 Production sold on the wholesale market can derive from production in excess of a host's load when a BTM installation is sized to produce more than the annual on-site consumption, as well as from installations interconnected on the grid side of the retail meter.

For these reasons, New York's past experience is instructive, but more mature markets without artificial constraints may at times be more instructive in anticipating future large-scale PV deployment in New York.

Further details are discussed in Section A9.5.

Alternative Distributional Deployment Scenarios

Three alternative cases for deployment scenarios as a percentage of the total capacity were developed. These include:

- A *base* deployment reflective of load distribution patterns in the state.
- A more urban- and distributed generation-focused deployment (*Alternative A*, or *Alt-A)* with moderately greater proportions of small-scale and urban installations than the base deployment.
- A more rural, larger-scale-focused deployment (*Alternative B*, or *Alt-B*) than the base deployment.

The derivation of these deployment assumptions is described further in Section A9.6, below.

A9.3 Standard System Sizes

As discussed above, standard PV system sizes were defined for each of four classes of installations, with the corresponding size ranges shown: (i) residential (up to 10 kW), (ii) small commercial (10 – 100kW), (iii) large commercial (101 – 1000 kW), and (iv) megawatt-scale (exceeding 1000 kW). As New York does not currently have a viable market for PV installations in excess of 100 kW, the size classes and standard characteristics were developed by consulting several sources. These included the NYSERDA CST Rebate Database as well as the Massachusetts SREC Database and New Jersey SREC Database. Table 163, Table 164 and Table 165 provide average system sizes by year for the system size ranges developed as part of this analysis.

Table 163. Average System Size by Class, NYSERDA CST Rebate Database

	0-10kW	10-100kW	100-1000kW*
2003	3.9	12.8	
2004	4.0	13.5	
2005	4.5	17.9	
2006	5.0	14.8	
2007	5.0	21.7	
2008	5.0	26.2	
2009	5.3	28.3	
2010	5.2	31.0	177.2
2011	5.7	32.7	177.7
*Note: Limited number of systems in the class size			

Table 164. Average System Size by Class, New Jersey SREC Program

	0-10kW	10-100kW	100-1000kW	1MW+
2007	6.0	46.4	300.2	1588.1
2008	4.3	40.3	286.9	1624.7
2009	2.9	54.7	291.1	1553.2
2010	6.8	26.8	335.9	2082.9
2011	6.4	22.6	299.4	1526.0

Table 165. Average System Size by Class, Massachusetts SREC Program Database

Year	1-10kW	10-100kW	100-1000kW	1MW+
2009	4.6	32.1	106.7	
2010	4.9	37.3	254.2	1406.5
2011	5.3	45.0	186.9	1800.9

For the residential system size case, an average 4 kW system size was assumed. The selection of this system size, slightly below the averages in the NYSERDA, New Jersey and Massachusetts databases, reflected the expectation that, as increasing numbers of homeowners install solar systems with declining installed costs, an increasing number of smaller, more urban and less ideal homes with lower consumption and less affluent homeowners will install PV systems. The difference between Massachusetts and New Jersey may exemplify the potential difference, as the Massachusetts program provides higher incentives for low-income homeowners and has a smaller average size.

For the small commercial size case, a 40 kW average system size was assumed. This size was selected as it is expected that an incentive program without an upper bound on incentives (i.e., 50 kW as in the existing NYSERDA program) may result in a larger average system size for this class than found in the current NYSERDA rebate program. This size also fits within the range of system sized found in both New Jersey and Massachusetts.

For the large commercial size class, a 400 kW average system size was assumed. Data for the few large commercial PV systems in New York were not considered representative of expected experience due to the current size caps on incentives. Systems will likely increase in size over time from the averages of the Massachusetts and New Jersey data sets as PV can be installed more economically on larger roofs. A generally increasing size trend has been observed throughout the industry, which is supported by observations through 2010 for Massachusetts and New Jersey and shown above.[231]

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231 It is unclear whether partial-year 2011 data is representative, as larger systems take longer to install and may come online later in the year bringing up the average size for the full year in line with recent trends.

The average size for megawatt-scale system was assumed to be two MW. Few large wholesale PV generators have been developed to date in either Massachusetts or New Jersey. It is expected that, as the New York market develops, a number of large MW-scale PV systems will be deployed, increasing the expected average size for this installation class over the average sizes found in either the Massachusetts or New Jersey datasets. Discussions with developers, and observations of planned projects, show a desire by developers to develop MW-scale projects as large as possible, up to 10 to 20 MW in size (although such sites are quite large and therefore the available sites at this scale in the Northeast are limited). In Massachusetts, a large number of projects in excess of two MW up to six MW, which is the state's SREC program size cap, are in the development pipeline.

A9.4 The Reference Case

In order to develop the reference case scenario, historical PV deployment was examined and future expected installations were projected based on existing incentive program trajectories. Historical data for this case was developed from data sets provided by NYSERDA, NYPA and LIPA.[232] Projections of annual installation by size and zone were developed based on stated program targets, historical distributions and assumed potential future scenarios. These are addressed for each program in the following sections.

NYSERDA Programs

NYSERDA currently operates two PV incentive programs, the customer-sited tier PV procurement and the regional competitive bidding program. For the customer sited tier, projected PV deployment for the reference case were developed based on estimates contained in the Public Service Board's recent authorizing order (N.Y. BSP, 2010) . Systems installed under this initiative in the future are assumed to follow the 2010 program installations size and load zone distributions. Table 166 shows the 2010 size distribution for this NYSERDA program.

Table 166. 2010 NYSERDA Program Rebate Statistics

2010 NYSERDA PROGRAM REBATE STATISTICS INSTALLED KW BY ZONE AND SYSTEM SIZE										
	Capital		Hudson Valley		New York		Upstate		Grand Total	
0-10 kW	950	22%	1,329	31%	483	11%	1,497	35%	4,258	28%
10-100 kW	2,594	24%	2,736	25%	3,012	28%	2,465	23%	10,807	70%
100-1000 kW				0%	100	28%	254	72%	354	2%

In the reference case, future funding for this program is assumed to continue through 2015, with 13.7 MW of PV installed each year until the end of the program.

232 NYSERDA Rebate Program Database (PONS 1050, 716, 2112); NYPA project database 1993-2011 (August); LIPA aggregate statistics provided by LIPA staff.

Installations from the recently launched NYSERDA geographic balancing program were also included in the reference case scenario, also based on the recent PSB order (N.Y. BSP, 2010). Projections in the order estimate that 15.43 MW of PV will be installed each year under the geographic balancing program between 2011 and 2015. For modeling purposes, several assumptions were made about the expected geographic distribution and system sizes under this initiative. First, 60% of capacity under the program was assumed to be installed in the Hudson Valley region and 40% in the NYC region based on a $17.5 million versus $12.5 million assumed annual funding split. In addition, systems installed under this program are assumed to be in the 100-1000kW size range, due to the open competitive nature of the program and the presence of scale economies. Megawatt scale systems were not assumed under this program given the likely site constraints in the designated load zones and the limits on proposer's previous experience.

LIPA Programs

LIPA operates two PV rebate initiatives, the Solar Pioneers and the Solar Entrepreneurs programs. These rebate programs have a combined 2010-2020 goal of installing 77 MW (LIPA, 2010). LIPA staff indicated that 10.9 MW had been installed under these programs in 2010 leaving 66.1 MW of capacity for the remaining 10 years of the plan. For the reference case, it was assumed that 6.6 MW would be installed in each remaining year of the program. In addition, it was assumed that the 2010 size distribution found in LIPA, with 79% of capacity in the residential class and 21% in the small commercial, would continue through the life of the program.

LIPA also has a megawatt-scale PV initiative that is currently in the implementation phase. The LIPA 2010-2020 plan reports an expected 50MW of installation under this initiative PV program (LIPA, 2010). As part of the program, a 32MW installation at Brookhaven Labs was commissioned in late 2011. In addition, an additional 13MW of ground mounted parking-lot sited systems are likely to be online under this program by the end of the year. The remainder of the megawatt scale program is assumed to be installed during 2011.

Reference Case PV Deployment

Snapshots of the reference case PV deployment for calendar year 2015, 2020 and 2025 is shown in Table 167, below.

Table 167. Reference Case Deployment

SIZE	LOCATION	2015		2020		2025	
		BTM	Grid	BTM	Grid	BTM	Grid
RESIDENTIAL	Upstate	11	0	11	0	11	0
	Capital	8	0	8	0	8	0
	Hudson Valley	11	0	11	0	11	0
	NY City	3	0	3	0	3	0
	Long Island	49	0	75	0	75	0
CI SMALL	Upstate	15	0	15	0	15	0
	Capital	14	0	14	0	14	0
	Hudson Valley	17	0	17	0	17	0
	NY City	16	0	16	0	16	0
	Long Island	9	0	16	0	16	0
CI LARGE	Upstate	35	0	35	0	35	0
	Capital	33	0	33	0	33	0
	Hudson Valley	80	0	80	0	80	0
	NY City	32	0	32	0	32	0
	Long Island	0	0	0	0	0	0
MW-SCALE	Upstate	0	0	0	0	0	0
	Capital	0	0	0	0	0	0
	Hudson Valley	0	0	0	0	0	0
	NY City	0	0	0	0	0	0
	Long Island	0	50	0	50	0	50
	Sub Totals	333	50	366	50	366	50
	Total	383		416		416	

A9.5 Base Deployment Scenario Assumptions

Assumptions were developed for each of the deployment scenarios modeled for total installed PV by system size class, geographic distribution and financial compensation distribution. The following sections describe the modeling assumptions for each of these parameters.

System Size Distribution

As the current New York PV fleet does not include substantial large commercial or megawatt scale PV systems, projections of system size distributions were based on historical trends, data from other states and consensus estimates developed.

The modeling of the base size distribution was based on the approximate size distribution found in the Massachusetts and New Jersey markets. This is a reasonable approximation of a potential future New York distribution as both of these states have large system size caps that allow for development across the range of potential system sizes. Table 168 shows the size distribution for the base deployment scenarios.

Table 168. Base Deployment Scenario System Size Distribution

Class	Size Range	Average Size	Percent of Total
Residential Scale	0-10kW	4 kW	15%
C&I Host Scale - Small	10-100kW	40 kW	20%
C&I Host Scale - Large	100-1000kW	400 kW	45%
Megawatt Scale	1MW+	2000 kW	20%

Production Financially Behind-the-Meter

The size of policy incentives necessary to defray the cost premium seen by PV system hosts and/or owners is based on the difference between the cost of energy from a PV installation and the value received by its owner from sales, or avoided purchases, of electricity. PV systems may be installed either on the customer side or the grid side of a retail meter. For those systems installed behind-the-meter, all, or a portion of the production may displace retail electricity purchases, either directly or financially, with any remaining amount being delivered to the grid and sold in wholesale markets. PV systems interconnected on the grid side of the retail meter will sell their production on the wholesale market, unless treated financially as part of a virtual net metering group.

The deployment scenarios include projections of the proportions of PV electricity production from New York PV systems will be financially compensated. Table 169 describes the modeling assumptions used for each system size. These assumptions are held constant across all scenarios.

Table 169. Percentage of Production Financially Behind-the-Meter

Class	Size Range	% of Production Financially Behind-the-Meter	% of Production Financially to Grid (Wholesale)
Residential Scale	0-10kW	100%	0%
C&I Host Scale - Small	10-100kW	90%	10%
C&I Host Scale - Large	100-1000kW	70%	30%
Megawatt Scale	1MW+	15%	85%

Figure 72 shows the resulting proportion of PV capacity falling into each size range over time for the Base Deployment, and Figure shows the proportion of production consumed behind-the-meter versus sold to the grid.

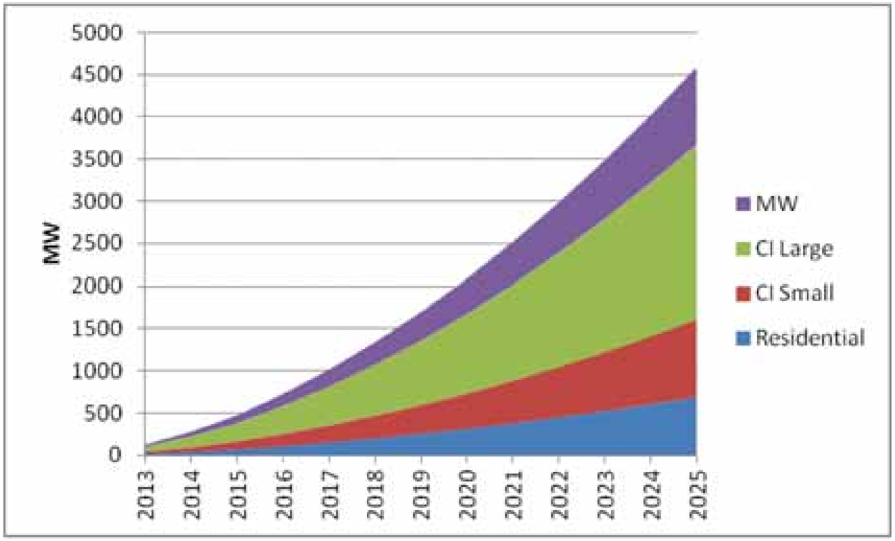

Figure 72. Base PV Deployment by Project Size Category, 2013-2025

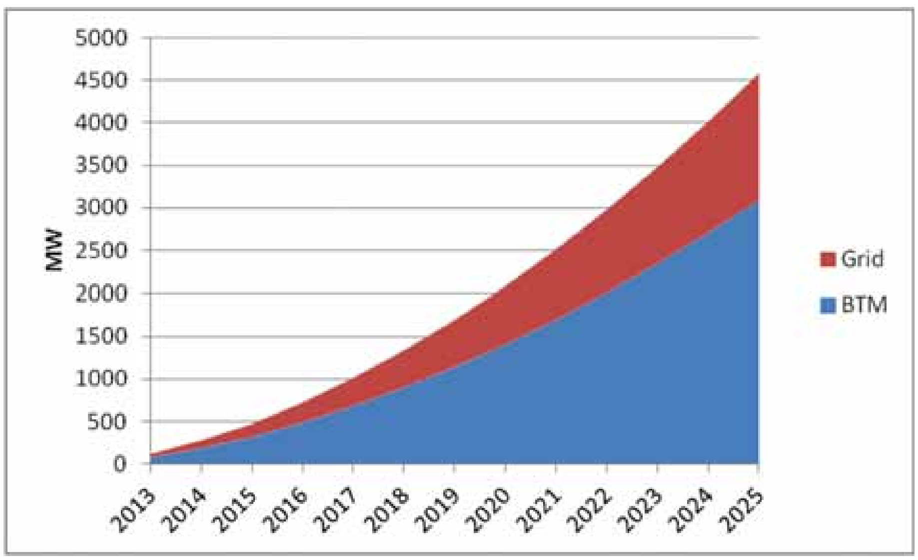

Figure 73. Base PV Deployment, Grid and BTM, 2013-2049

The rationale for these assumptions is as follows.

- Residential Scale. All residential systems are assumed to be 100% financially behind-the-meter, consistent with current industry experience and existing net metering regulations in New York
- Small C&I Scale. For the small commercial and industrial scale installations, data from New Jersey and the PJM grid operator suggest that nearly all of the production from systems smaller than 100 kW in operation

today is treated financially as on-site production due to net metering. With growing system sizes (an observed trend industry-wide) in a market without artificial constraints, in the presence of policies (such as those described in Chapter 9) that offer opportunities for premium revenue from PV sales to the grid, it would be expected that some systems at the larger end of the scale (potentially with aggregation) would sell at least some of their production to the grid. In other words, the availability of SREC revenues for sales of excess production the grid may remove a constraint on optimizing system size installation to a site. A small percentage of sales from this class were therefore assumed to be at wholesale.

- Large C&I Scale. Likewise, for large commercial and industrial systems, New Jersey and PJM grid operator date suggests that a high percentage of the production from systems between 100 kW and 1000 kW today treated financially as on-site production due to net metering. For the same reasons articulated for small C&I systems, it was assumed that some installations in this size class would be sized to the site and would sell at least some of their production to the grid, particularly at the larger end of scale able to capture scale economies. A somewhat larger proportion of sales from this class were assumed to be at wholesale.
- MW-Scale. New Jersey has 75% of projects of one MW and greater interconnected behind-the-meter. Still, the net metering cap in New Jersey constrains sizing of system annual output to no more than annual energy consumption. This is an artificial constraint on system configuration that is not assumed to apply in New York under future PV incentive policies. The largest projects in the New Jersey market are in the five to six MW range with most projects less than two MW. It is expected the increasing project size trend to continue. Likewise, in Massachusetts, developers are building on many locations with minimal on-site load, indicating that if economics support it, developers will build as large as they can, subject to site scale constraints. If not constrained to net metering installations in New York, an artificial constraint would be relieved on sites with little or no onsite load, such as capped landfills and brownfield sites that are targets for solar developments in other states not limited by net metering. As a result, it is reasonable to assume that larger projects would be built that could put most or all of their production directly to the grid.

Geographic Distribution

Assumptions for PV system geographic distribution were developed for each deployment scenario. The base deployment scenario PV distribution to the five aggregated geographic regions was based on the relative load distribution found in the 2011 State Energy Plan IPM reference case. One adjustment was made to this distribution. Because of the limitations of installing MW-scale PV in the NYC region, 80% of the distribution that would have been allocated to the NYC MW-scale systems was redistributed to other regions in proportion to their forecast load. The base deployment assumptions by system size class are shown in Table 170.[233]

[233] The resulting capacity by region is shown in Figure 74.

Table 170. Base Deployment Geographic Distribution

BASE	UPSTATE	CAPITAL	HUDSON VALLEY	NY CITY	LONG ISLAND
Residential Scale	33.9%	6.5%	12.1%	33.6%	13.9%
C&I Host Scale - Small	33.9%	6.5%	12.1%	33.6%	13.9%
C&I Host Scale - Large	33.9%	6.5%	12.1%	33.6%	13.9%
Megawatt Scale	47.6%	9.1%	17.0%	6.7%	19.6%

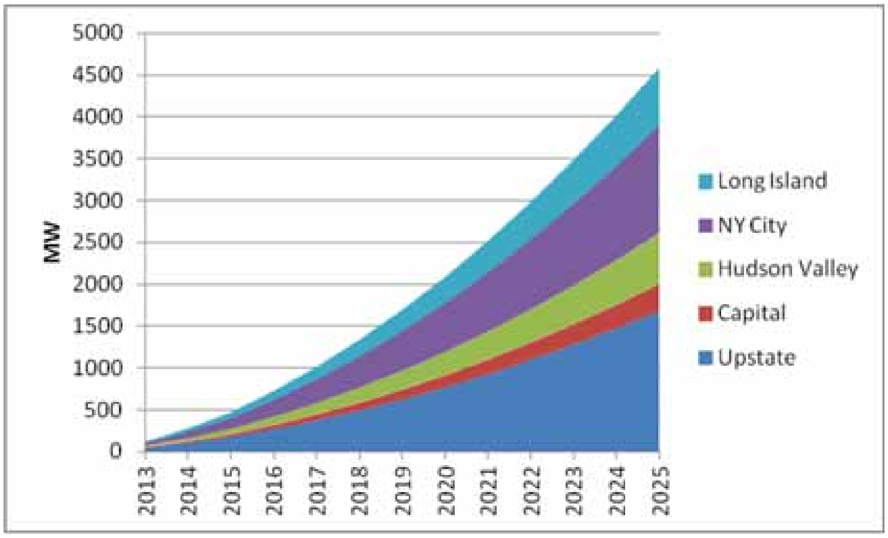

Figure 74. Base PV Deployment by Region, 2013-2025

A9.6 Alternative Deployment Scenario Assumptions

To test the sensitivity of the study's results to design choices that might favor installation distributions that are not proportional to the distribution of load across New York state, two alternative distributions were developed, referred to as *Alternative A* (*Alt-A*) and *Alternative B* (*Alt-B*). Alt-A represents a more urban- and distributed generation-focused deployment than found in the base case. Alt-A is therefore comprised of a moderately greater proportion of small-scale and urban installations than the base deployment. Alt-B, on the other hand, is tilted more towards larger-scale systems capturing better scale-economies. Such a deployment would be expected to have a lower direct cost of installations, although due to variations in the value of the electricity produced, the relative cost and benefit compared to a base deployment requires additional analysis whose results are described in Chapter 5. The Alt-B distribution, due to the land-use patterns, implies a less urban, more rural distribution that the base deployment scenario.

The system size distribution for the Alt-A deployment scenario is the same as for the base deployment scenario, as described in Table 168. For the more rural Alt-B deployment scenario, the percentage of MW-scale PV installations was doubled over the base and urban cases. This substantial increase in the MW-scale class was offset by reductions in each of the other system size classes. This distribution approximates the size distribution in the New Jersey market. Table 171 shows the system size distribution for the Alt-B deployment scenario.

Table 171. Alt-B Rural Case Size Distribution

Class	Size Range	Percent of Total
Residential Scale	0-10kW	10%
C&I Host Scale - Small	10-100kW	15%
C&I Host Scale - Large	100-1000kW	35%
Megawatt Scale	1MW+	40%

For the Alt-A deployment scenario, the proportion of PV installations in the NYC, Hudson Valley and Long Island regions was increased with a corresponding decrease in the Upstate and Capital regions. The percentage allocations of annual target capacity for each size class are shown in Table 172.

Table 172. Alternative A (DG/Urban) Geographic Distribution

CLASS	UPSTATE	CAPITAL	HUDSON VALLEY	NYC	LONG ISLAND
Residential Scale	17.0%	4.9%	15.9%	44.0%	18.3%
C&I Host Scale - Small	17.0%	4.9%	15.9%	44.0%	18.3%
C&I Host Scale - Large	17.0%	4.9%	15.9%	44.0%	18.3%
Megawatt Scale	47.6%	9.1%	17.0%	6.7%	19.6%

The Alt-B deployment scenario favors more installations in rural load zones, particularly in the large commercial and MW-scale size classes. For this scenario, Upstate and Capital region large commercial and MW-scale installations were increased while the same size classes were correspondingly reduced in the NYC, Long Island and Hudson Valley regions. The percentage allocations of annual target capacity for each size class are shown in Table 173.

Table 173. Alternative B (Rural/Scale) Geographic Distribution

CLASS	UPSTATE	CAPITAL	HUDSON VALLEY	NYC	LONG ISLAND
Residential Scale	33.9%	6.5%	12.1%	33.6%	13.9%
C&I Host Scale - Small	33.9%	6.5%	12.1%	33.6%	13.9%
C&I Host Scale - Large	46.4%	8.9%	9.1%	25.2%	10.5%
Megawatt Scale	62.2%	11.9%	12.7%	3.4%	9.8%

A9.7 PV Policy Deployment Alternative Scenario Projections

Figure 75 shows the cumulative PV capacity in each geographic region, and by installation type, for each of the deployment scenarios analyzed in this study. Table 174 shows the detailed cumulative annual PV capacity in each geographic region by installation type for the Base, Alt-A and Alt-B deployment scenarios. It also includes the proportion of PV production assumed to be financially behind-the-meter versus PV production selling into the wholesale market. These deployments are used in the sensitivity analysis described in Chapter 5.

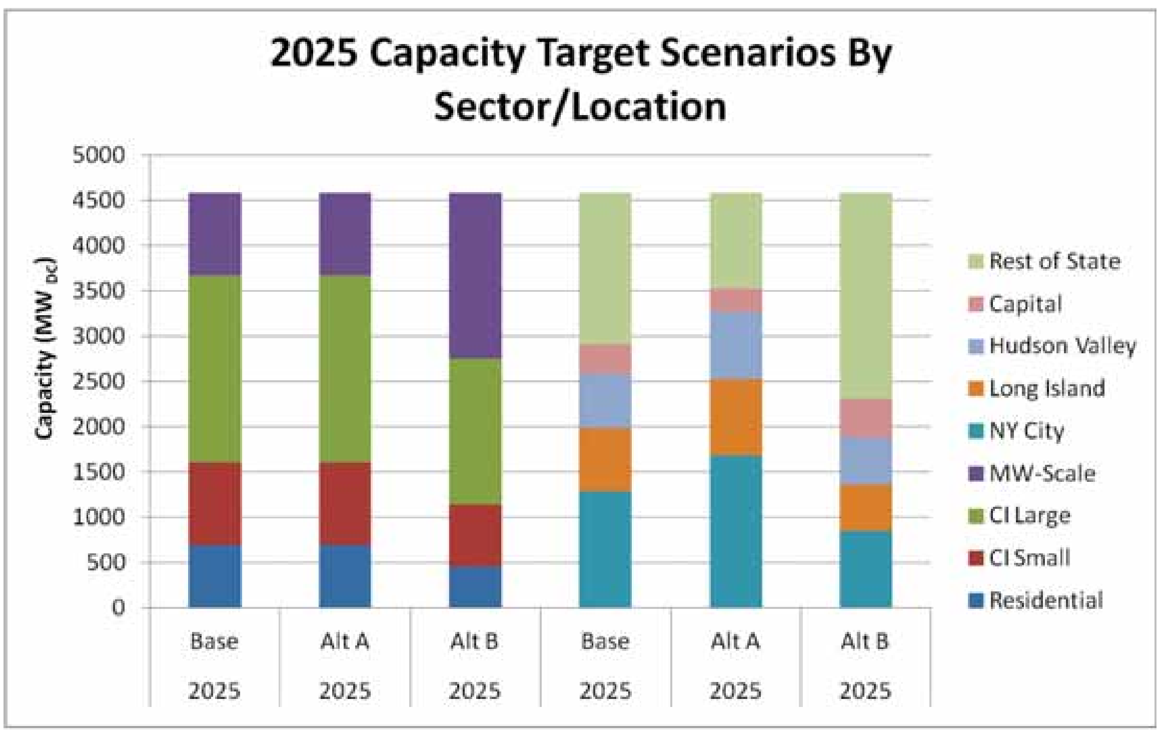

Figure 75. 2025 Size and Geographic Distribution of Additional PV under Base, Alt-A and Alt-B Deployment Scenarios

Table 174. Detailed Deployment Scenario Projections, 2015, 2020 and 2025

		BASE DEPLOYMENT						ALTERNATIVE A (URBAN/DG)						ALTERNATIVE B (RURAL/SCALE)					
SIZE	LOCATION	2015		2020		2025		2015		2020		2025		2015		2020		2025	
		BTM	Grid	BTM	Grid	BTM	Grid	BTM	Grid	BTM	Grid	BTM	Grid	BTM	Grid	BTM	Grid	BTM	Grid
RESIDENTIAL	Upstate	24	0	106	0	233	0	12	0	53	0	117	0	16	0	71	0	156	0
	Capital	5	0	20	0	45	0	3	0	15	0	33	0	3	0	14	0	30	0
	Hudson Valley	9	0	38	0	83	0	11	0	50	0	109	0	6	0	25	0	55	0
	NY City	24	0	105	0	231	0	31	0	138	0	303	0	16	0	70	0	154	0
	Long Island	10	0	44	0	96	0	13	0	57	0	126	0	7	0	29	0	64	0
CI SMALL	Upstate	29	3	127	14	280	31	14	2	64	7	140	16	22	2	96	11	210	23
	Capital	5	1	24	3	53	6	4	0	18	2	40	4	4	0	18	2	40	4
	Hudson Valley	10	1	45	5	100	11	13	1	60	7	131	15	8	1	34	4	75	8
	NY City	28	3	126	14	277	31	37	4	165	18	363	40	21	2	94	10	208	23
	Long Island	12	1	52	6	115	13	16	2	69	8	151	17	9	1	39	4	86	10
CI LARGE	Upstate	50	22	223	96	490	210	25	11	111	48	245	105	54	23	237	102	522	224
	Capital	10	4	43	18	94	40	7	3	32	14	70	30	10	4	45	19	100	43
	Hudson Valley	18	8	79	34	175	75	24	10	104	45	229	98	10	4	46	20	102	44
	NY City	50	21	220	94	485	208	65	28	289	124	636	273	29	12	129	55	283	121
	Long Island	21	9	92	39	201	86	27	12	120	51	264	113	12	5	53	23	117	50
MW-SCALE	Upstate	7	38	30	169	66	371	7	38	30	169	66	371	18	100	78	441	171	970
	Capital	1	7	6	32	13	71	1	7	6	32	13	71	3	19	15	84	33	185
	Hudson Valley	2	14	11	60	23	132	2	14	11	60	23	132	4	20	16	90	35	198
	NY City	1	5	4	24	9	52	1	5	4	24	9	52	1	5	4	24	9	52
	Long Island	3	16	12	69	27	153	3	16	12	69	27	153	3	16	12	69	27	153
	Sub Totals	319	153	1407	677	3096	1490	316	153	1408	678	3095	1490	256	214	1125	958	2477	2108
	Total	472		2084		4586		469		2086		4585		470		2083		4585	

APPENDIX 10 – THE POWER NY ACT OF 2011

S. 5844 A. 8510

2011-2012 Regular Sessions

S E N A T E - A S S E M B L Y

June 22, 2011

AN ACT to amend the public service law, the public authorities law, the real property law, the state finance law, and the environmental conservation law, in relation to establishing the power NY act of 2011

THE PEOPLE OF THE STATE OF NEW YORK, REPRESENTED IN SENATE AND ASSEMBLY, DO ENACT AS FOLLOWS….

[Section 22: Pgs 31 – 32: Solar Study]

S 22. Study to Increase Generation from Photovoltaic Devices in New York. 1. Legislative Intent. The legislature hereby finds and declares that solar energy generation from photovoltaic devices in New York represents less than 0.01 percent of the State's electricity generation. While the current cost of electricity from photovoltaic devices is a premium above market price for electricity from most other fuels, the cost of installing such photovoltaic generation is declining and increasing solar energy generation represents a significant opportunity for the development of the State's clean energy economic sector and the creation of new high technology jobs in New York.

2. The New York state energy research and development authority, in consultation with the department of public service, is hereby authorized and directed to conduct a study with respect to increasing generation from photovoltaic devices in New York, including, but not limited to, the following:

a. Identify administrative and policy options that could be used in achieve goals of two thousand five hundred megawatts of generation from photovoltaic devices in New York by 2020 and five thousand megawatts by 2025.

b. Conduct a targeted analysis of the per megawatt cost of achieving increased generation from photovoltaic devices and the costs of achieving the goals specified in paragraph a of this subdivision using each of the options identified in the analysis conducted pursuant to such paragraph.

c. Conduct an analysis of the net economic and job creation benefits of achieving the goals specified in subdivision a of this section using each of the options identified in the analysis conducted pursuant to such subdivision.

d. Conduct an analysis of the environmental benefits of achieving the goals specified in paragraph a of this subdivision using each of the options identified in the analysis conducted pursuant to such paragraph.

3. The New York state energy research and development authority shall report to the governor and the legislature on the findings and recommendations of the study conducted pursuant to subdivision two of this section on or before January 31, 2012.

APPENDIX 11 – ENVIRONMENTAL IMPACTS ANALYSIS (CH. 8)

Table 175. Impact of Base PV Scenario on Fuel Usage of NY Generators

Value	2014	2015	2016	2020	2025	2030	2035
Coal Consumption (Tbtu)	(1.60)	(1.30)	(2.50)	(4.20)	(7.50)	(10.10)	(10.50)
Gas Consumption (Tbtu)	0.80	(2.30)	(3.10)	(10.40)	(19.70)	(14.50)	(21.10)
Oil Consumption (Tbtu)	(0.10)	(0.30)	(0.30)	(0.50)	(0.80)	(0.40)	-

Table 176. Impact of Base PV Scenario on Emission Levels of NY Generators

Value	2014	2015	2016	2020	2025	2030	2035	Study Period (2013-2049)
CO2 Emissions (Tons)	(112,299)	(264,801)	(423,800)	(1,004,799)	(1,823,700)	(1,773,899)	(2,131,802)	(46,787,524)
NOX Emissions (Tons)	(128)	(220)	(323)	(621)	(869)	(1,367)	(1,742)	(67,361)
SO2 Emissions (Tons)	(2)	(805)	(866)	(1,593)	(2,540)	(2,989)	(2,885)	(33,452)
Mercury Emissions (Pounds)	2.20	(0.60)	(1.60)	(2.60)	(4.20)	(5.40)	(5.40)	(116)

Table 177. Monetized Carbon Benefits, Base PV Scenario, 2013-2049 (Nominal $)

Base Carbon Value					
2013	4,409,471	**2026**	55,336,120	**2039**	62,811,262
2014	8,451,486	**2027**	57,379,853	**2040**	58,651,703
2015	15,778,384	**2028**	59,460,596	**2041**	54,219,927
2016	14,962,597	**2029**	61,617,823	**2042**	49,504,218
2017	19,152,380	**2030**	63,773,247	**2043**	44,492,422
2018	23,503,709	**2031**	66,227,393	**2044**	39,171,937
2019	28,016,585	**2032**	68,769,547	**2045**	33,529,695
2020	32,691,008	**2033**	71,402,025	**2046**	27,552,143
2021	36,610,399	**2034**	74,127,143	**2047**	21,225,232
2022	40,596,938	**2035**	76,947,219	**2048**	14,534,395
2023	44,731,982	**2036**	73,767,573	**2049**	7,464,535
2024	48,988,412	**2037**	70,358,505		
2025	53,403,058	**2038**	66,709,900		
High Carbon Value					
2013	31,260,508	**2026**	392,299,937	**2039**	445,294,216
2014	59,915,973	**2027**	406,788,776	**2040**	415,805,435
2015	111,859,286	**2028**	421,539,998	**2041**	384,386,798
2016	106,075,851	**2029**	436,833,443	**2042**	350,955,242
2017	135,778,899	**2030**	452,114,114	**2043**	315,424,614
2018	166,627,217	**2031**	469,512,537	**2044**	277,705,566
2019	198,620,804	**2032**	487,534,882	**2045**	237,705,446
2020	231,759,660	**2033**	506,197,573	**2046**	195,328,184
2021	259,545,792	**2034**	525,517,031	**2047**	150,474,175
2022	287,807,966	**2035**	545,509,679	**2048**	103,040,156
2023	317,122,950	**2036**	522,967,896	**2049**	52,919,082
2024	347,298,489	**2037**	498,799,647		
2025	378,595,682	**2038**	472,933,222		

APPENDIX 12 – PV POLICY MECHANISMS ANALYSIS DETAIL (CH. 10)

A12.1. Design Details

For each policy, implementation details are defined to address the following key questions:

- What are the key features of the policy?
- How does the policy meet the desired targets?
- How are incentives targeted to different market segments to achieve a desired deployment? (tiers, differentiation)
- What is the duration of policy support?
- Who administers the program?
- Who provides the cash incentive?
- What commodities are transferred or purchased?
- What is the price structure?
- What degree of revenue certainty is expected for the system owner (market risk remaining)?
- What cost control mechanisms are used?
- What policy adjustment mechanisms are utilized?

In selecting a solar policy, state policymakers may elect to vary key design details from those assumed herein. The potential impact of varying such choices is identified below wherever the impacts of such design choices may materially impact policy costs or deployment. These questions are addressed in the description of each policy option below.

Solar Quantity Obligation with Price Floor

Key Features

The key features of this model include head-to-head competition between generators, establishment of a price floor to provide a degree of revenue certainty, and design of the price floor to achieve desired incentives over time.

- **Quantity Obligation**: The quantity obligation is a demand target placed on load-serving entities (LSEs).[234] While quantity obligations in general need not utilize the purchase of SRECs as a means of demonstrating compliance, for solar installations primarily located behind-the-meter, SRECs are the obvious compliance tool. A key feature of a quantity obligation is head-to-head price competition among eligible generators in selling SRECs to meet the LSE demands.

- **Creating a Price Floor**: A major challenge with this approach is *how* to establish a price floor. For a price floor to be effective at providing revenue certainty sufficient to attract debt financing, or equity investment at reasonable cost, it must be seen as financeable, with a credit-worthy entity serving as the party to provide payment at the level of the floor in the event a market-derived price falls below the floor. There is little experience in creating an effective solar quantity obligation price floor at scale.[235] Two neighboring states have sought to utilize a price floor. Massachusetts is attempting to establish a floor price through a fixed price 'clearinghouse' auction, which uses a variety of incentives to lure buyers into purchasing RECs at a fixed floor price if they cannot find buyers at a higher price. The Massachusetts approach is untested, and it is unclear whether it will work as designed. The other available example is used as a parallel policy mechanism accompanying the SREC market created by New Jersey's solar RPS tier. One of New Jersey's utilities, PSE&G, has implemented a regulator- approved voluntary program in which it extends loans for small solar installations, where repayments are made in RECs with a minimum purchase price serving as a price floor. If the price floor is used, the difference between the price credited to SRECs delivered to PSE&G and the market price of SRECs is recovered in retail rates.

  A mechanism to implement a price floor at large scale requires substantial financial backing, the feasibility of which is unproven. For purposes of this study, it is assumed that an approach is developed to fund a floor, such as relying on credit-worthy EDCs committing to purchase SRECs at a floor price, and reselling those SRECs at market prices with ratepayers paying the difference in retail rates.

- **Design of Price Floor**: This policy would utilize a *differentiated* price floor for installations in each year, set at 85% of applicable 25-yr fixed-revenue LCOE for each size and location. The 85% level was selected as a rough estimate of a level that may be sufficient to entice a reasonable degree of debt investment. Differentiating the price floor assures that projects of different sized and in different locations would each be potentially attractive investments. In the absence of such differentiation, a quantity obligation would be most likely to incentivize only the installation sizes and locations with the lowest cost premium, which could result in a high concentration that would be radically different than the target deployment.

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234 Load-serving entities, or LSEs, are the generation service providers to retail customers. They consist of competitive energy service companies (ESCOs) and the electric distribution companies to the extent they serve as provider of last resort for those customers not electing ESCO supply.

235 A notable exception to this is the state of Flanders in Belgium which utilizes a quantity obligation supported by tradable renewable energy credits. Under the Flemish system, generators can lock into a 20-year price floor for RECs. In 2011, the price floor for PV was set at 270 €/MWh. If the price floor is utilized, the payment is made by the distribution system operators (Teckenburg et al., 2011), who then resell RECs on the market and pass through any shortfalls to all distribution customers. In 2010, Belgium was the fifth largest market in Europe and installed 424 MW of new capacity. The majority of this market growth occurred in Flanders.

With the expectation of falling PV costs, to make projects installed in different years financeable, a different price floor would be established applicable to installations in each year. In this manner, an installation in 2013, for example, would be able to rely on a known floor price for a known period; but as solar costs decline over time, an installation in 2015 would be eligible for a lower price floor. The floor applicable to installations in each year would decline following the LCOE trajectory.

Design Details

The remaining design details are described in Table 178 below.

Table 178. Design Details, Solar Quantity Obligation with Price Floor

FEATURE	DESCRIPTION	DESIGN VARIATIONS & IMPLICATIONS
How does the policy meet the desired targets?	Set requirements equal to targets	
How are incentives targeted to different market segments to achieve a desired deployment? (tiers, differentiation)	Floor price differentiation	Undifferentiated price floor would favor least-cost installations, losing geographic and size diversity, although policy cost may be reduced because of economies of scale
What is the duration of policy support?	25 year price floor	A floor price made available for shorter duration would raise SREC prices in early years, with lower premiums in later years, thus frontloading the policy cost.
Who administers the program?	State agency (e.g. PSC) administers compliance with SREC QO while EDC administers price floor	
Who provides the cash incentive?	LSEs provide SREC payments; EDCs provide payments when market SREC prices fall below price floor, with costs passed along to ratepayers	
What commodities are transferred or purchased?	SRECs	
What is the price structure?	Variable SREC prices determined by market; price floor set on a VIMG basis	A fixed SREC price floor would place additional market revenue risk on system owners, increasing financing costs
What degree of revenue certainty is expected for the system owner (market risk remaining)?	Partial. (price risk mitigated by price floor. Since floor set at level insufficient to provide adequate equity investor returns, risk remains above the floor)	

FEATURE	DESCRIPTION	DESIGN VARIATIONS & IMPLICATIONS
What cost control mechanisms are used?	Alternative Compliance Payment serves as cost cap; Banking of surplus RECs allowed.	
What policy adjustment mechanisms are used?	Each successive year's installations would have their own price floor, which would drop as PV prices drop; VIMG indexing of floor price annually.	

EDC Long-Term Contract Auction

Key Features

The key features of the EDC long-term contract auction policy modeled include who conducts the auction, what is purchased in the auction and the auction mechanism. The buyer offering the contracts must be a sufficiently credit-worthy entity for the contract to support financing, which rules out placing the requirement on LSEs. Options therefore include EDCs buying on behalf of their entire distribution load, or NYSERDA acting as a central procurement agent funded by collections from the EDCs. For the purposes of modeling this policy, the EDC alternative is assumed.[236] Generation delivered to the grid is assumed to be purchased bundled with SRECs at fixed price. For generation consumed on-site by a host displacing retail purchases, SRECs are assumed to be purchased using a VIMG pricing approach. It is also assumed that each EDC runs distinct auctions for different project sizes, in order to stimulate a diverse distribution of locations and project sizes.

An auction could be run on either a clearing price basis, with all bidders paid the same price, or an as-bid basis, where each selected bidder is paid their bid price. In an auction with many bidders, a single technology, and separate auctions for different project sizes, a clustering of bid prices is likely. This clustering suggests that the difference in total cost between an as-bid and clearing price auction may be small. For purposes of this study, an as-bid auction is assumed where the weighted average price of installations in each size and location selected for contracting through the auction in each year is assumed to equal the 25-year LCOE applicable to that year.

As discussed in Section 10.2.2.3, the transaction costs for small generators to engage in a competitive auction are substantial. For this reason, it is assumed that the auction structure allows for and encourages aggregators to participate in the auctions on behalf of many aggregated small PV systems.

Design Details

Remaining design details are described in Table 179 below.

236 It is assumed that any electricity purchased under auction contracts is either utilized as part of the EDC's provider of last resort supply, or resold into the NYISO wholesale markets.

Table 179. Design Details, EDC Long-Term Contract Auction

FEATURE	DESCRIPTION	DESIGN VARIATIONS & IMPLICATIONS
How does the policy meet the desired targets?	Set auction volume targets equal to target quantities	
How are incentives targeted to different market segments to achieve a desired deployment? (tiers, differentiation)	Each EDC would establish tiers (separate auctions) by size to accomplish deployment distribution. Separate EDC auctions provide geographic diversity.	EDCs covering multiple zones could also establish tiers by location.
What is the duration of policy support?	25 year contracts	A shorter contract duration would front-load policy costs, increasing LCOE during the contract term above the 25-year cost, but if no post-contract policy, no customer premiums in later years of each project's life.
Who administers the program?	EDCs under PSC oversight	
Who provides the cash incentive?	EDCs provide contract payments	
What commodities are transferred or purchased?	Sold to grid: SRECs and electricity Consumed behind-the-meter: SRECs only	An alternative approach conveying just SRECs for both in front of the meter and behind-the-meter systems could also be utilized (see discussion under price structure below)
What is the price structure?	Contract prices set on a fixed-price basis for bundled electricity and SRECs, and on a VIMG basis for SREC contracts	Alternatively only SRECs could be purchased, either using a VIMG pricing approach (with similar net costs), or a fixed price for SRECs. Fixed price SREC contracts would place additional market revenue risk on system owners, increasing financing costs
What degree of revenue certainty is expected for the system owner (market risk remaining)?	Revenue would be certain under 25-year contracts, leaving no remaining market risk on system owners	If only SRECs are purchased on a fixed price basis, system owners would continue to be exposed to market price risk.
What cost control mechanisms are used?	Competitive procurement, capped MW targets	Could also use benchmark prices
What policy adjustment mechanisms are utilized?	VIMG indexing of SREC contract price annually.	

Upfront Incentive/Central Procurement Hybrid

This hybrid policy uses two distinct approaches for projects of different scale. Smaller generators whose output is predominantly consumed by host customers would be eligible for a upfront capacity-based incentive program similar to the current RPS customer-sited tier's solar programs. Upfront incentives are assumed to be available to residential and small C&I-hosted systems. For larger installations (Large C&I and MW-Scale), an extension of the New York Main Tier Central Procurement approach is targeted to PV installations. The key features and design details associated with each are discussed separately below.

Key Features

Upfront Incentives for Residential and Small C&I Systems: This study assumes that capacity-based up-front payments are coupled with performance assurance measures such as warranties and testing periods. For modeling purposes, the total cost of the system is assumed to be reduced by the upfront incentive payment from the outset.[237]

Central Procurement of SRECs by NYSERDA under long-term contracts from Large C&I hosted and MW-Scale systems: While the current NYSERDA Main Tier RPS uses an as-bid approach, application of the approach to PV installations provides a more homogenous set of bidders and a deeper market (many more generators), conditions favorable for use of a clearing-price approach. It is assumed that this policy could utilize either a clearing-price or as-bid approach. For modeling purposes, an as-bid auction is assumed where the weighted average price of installations in each size and location selected for contracting through the auction in each year is assumed to equal the 25-year LCOE applicable to that year.

Design Details

The remaining design details associated with the upfront incentive portion of this policy are described in Table 180 below.

Table 180. Design Details, Upfront Incentives for Smaller Installations

FEATURE	DESCRIPTION	DESIGN VARIATIONS & IMPLICATIONS
How does the policy meet the desired targets?	Incentives are set at a level sufficient to attract investment, with volumes limited to targets by capped budget limits	
How are incentives targeted to different market segments to achieve a desired deployment? (tiers, differentiation)	Incentive levels would be tiered by location & size to accomplish a desired deployment distribution	
What is the duration of policy support?	Up-Front	
Who administers the program?	NYSERDA	
Who provides the cash incentive?	NYSERDA	

237 Alternatively, rebate payments may be provided shortly after a system is commissioned, which would mean that either the installer or the owner would need to front the cost of the system until rebate payment is made.

FEATURE	DESCRIPTION	DESIGN VARIATIONS & IMPLICATIONS
What commodities are transferred or purchased?	SRECs retained by NYSERDA for project life	Possible alternative: no SRECs issued to projects participating in program
What is the price structure?	Fixed Payment	Could have performance-based characteristics
What degree of revenue certainty is expected for the system owner (market risk remaining)?	While the amount of the up-front incentive would be known, system owners would be exposed to electricity market value risk	
What cost control mechanisms are used?	Capped MW targets in each tier, along with an annual budget cap	
What policy adjustment mechanisms are utilized?	Price degression to reduce upfront incentives in line with cost declines over time	

The remaining design details associated with the central procurement portion of this policy are described in Table 181 below.

Table 181. Design Details, Central Procurement for Larger Installations

FEATURE	DESCRIPTION	DESIGN VARIATIONS & IMPLICATIONS
How does the policy meet the desired targets?	Procurement targets are set at the desired level, and funding is collected by EDCs through SBC/RPS-like charges	
How are incentives targeted to different market segments to achieve a desired deployment? (tiers, differentiation)	Separate procurements would be established for each location & size to accomplish a desired deployment distribution	
What is the duration of policy support?	25 year contracts	A shorter contract duration would front-load policy costs, increasing LCOE during the contract term above the 25-year cost, but if no post-contract policy, no premiums in later years of each project's life.
Who administers the program?	NYSERDA	
Who provides the cash incentive?	NYSERDA	
What commodities are transferred or purchased?	SRECs only	

FEATURE	DESCRIPTION	DESIGN VARIATIONS & IMPLICATIONS
What is the price structure?	Fixed revenues are established through contract prices for SRECs using a VIMG pricing approach	
What degree of revenue certainty is expected for the system owner (market risk remaining)?	Revenue would be certain under 25-year contracts, leaving no remaining market risk on system owners	If SRECs are purchased on a fixed price basis, system owners would continue to be exposed to market price risk.
What cost control mechanisms are used?	Competitive procurement, capped MW targets, budget cap, and a maximum price benchmark	
What policy adjustment mechanisms are utilized?	VIMG indexing of SREC contract price annually.	

Standard Offer PBI/Auction Hybrid

This hybrid policy also uses two distinct approaches for projects of different scale. Smaller generators whose output is predominantly consumed by host customers would be eligible for a standard offer PBI, a long-term incentive available on a standing basis to eligible generators. A standard offer PBI is assumed to be available to residential and small C&I-hosted systems. Larger installations (Large C&I and MW-Scale) would compete for long-term contracts made available to the lowest bidders via an EDC-administered auction. The key features and design details associated with the Standard Offer are discussed below; the features and details of the auction are as already described in above.

Key Features

For the system sizes targeted by the Standard Offer, it was assumed that all (for residential installations) or most (for small C&I systems) of the system production is consumed by the host behind the retail meter. The key features of a Standard Offer include:

- A long-term standing price available to system owners for eligible systems without the need to compete. This approach minimized the risk to investors as well as eliminating costs associated with competing and contracting (which are proportionally higher for small systems), and which in principle should result in a lower LCOE than other long-term contracting approaches for small systems.
- Standard offers pose a design challenge in setting the price at the right level. If too low, few systems will get build; if too high, the market can get overheated. Careful application of best practices to cost control and price adjustment can effectively tune the price towards the optimum level without substantial over-subscription.[238]

[238] The risks and benefits are similar to those used in NYSERDA's CST solar current rebate program, which is effectively a standard offer of an upfront payment. NYSERDA already has experience with adjusting solar rebate levels over time to achieve desired outcomes, avoiding the oversubscription seen in some European feed-in tariffs.

- Key inter-related design decisions include who offers the standard offer PBI, what is purchased, and the price structure. Either EDCs or NYSERDA could extend and administer a standard offer PBI. This analysis assumes use of a VIMG price structure for SREC-only purchases would leave system owners with revenue certainty and no remaining market price risk. As an alternative, a standard offer PBI could be offered for fixed-price SRECs, leaving electricity price risk on the system owners and likely increasing the cost of financing systems. If offered by the EDCs, for example through a feed-in tariff, the EDC could opt to purchase the small quantities of electricity assumed delivered to the grid by small C&I systems on a fixed-price, bundled basis, an alternative not available if NYSERDA administers this portion of the policy.
- Standard offer prices would be differentiated for different project sizes to encourage project size diversity.
- How geographic distribution would be accomplished depends on who administers the standard offer PBI. If offered by each EDC in volumes proportional to their overall distribution load, a substantial degree of geographic distribution is automatic. If administered by NYSERDA, the standard offer would be targeted to different locations through a combination of differentiation, eligibility and/or MW caps or quotas.
- Finally, a standard offer PBI requires a means of queuing to provide the ideal certainty of access to the standard offer price in order to unlock the benefits of revenue certainty.

Design Details

The remaining design details associated with this policy are described in Table 182 below.

Table 182. Design Details, Standard Offer PBI

FEATURE	DESCRIPTION	DESIGN VARIATIONS & IMPLICATIONS
How does the policy meet the desired targets?	Combine prices sufficient to attract investment with MW caps	
How are incentives targeted to different market segments to achieve a desired deployment? (tiers, differentiation)	If offered by EDCs: by system size; If offered by NYSERDA, tiering by size and location	
What is the duration of policy support?	25 year contracts	A shorter contract duration would front-load policy costs, increasing LCOE during the contract term above the 25-year cost, but if no post-contract policy, no premiums in later years of each project's life.
Who administers the program?	EDCs or NYSERDA	
Who provides the cash incentive?	EDCs or NYSERDA	
What commodities are transferred or purchased?	SRECs	As described above, if offered by EDCs, EDC could also purchase electricity delivered to the grid

FEATURE	DESCRIPTION	DESIGN VARIATIONS & IMPLICATIONS
What is the price structure?	Fixed revenues are established through contract prices for SRECs using a VIMG pricing approach	Alternative, fixed-price SRECs could also be used, shifting electricity price risk to system owners and increasing cost of finance
What degree of revenue certainty is expected for the system owner (market risk remaining)?	Revenue would be certain under 25-year contracts, leaving no remaining market risk on system owners	
What cost control mechanisms are used?	MW caps, price degression.	
What policy adjustment mechanisms are utilized?	Dynamic price degression; VIMG indexing of SREC contract price annually.	Alternatively, the Standard Offer price could be adjusted over time based on recent results of the EDC auction, adjusted to reflect differences in price for scale economies.

Design details for the EDC Long-Term Contract Auction for Large C&I and MW-scale installations are described in Table 179.

A12.2. LCOE and Upfront Incentive Projections

Table 183. LCOE ($/MWh nominal) for Installations for Solar QO with Price Floor

Region	Size	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Upstate	Residential	48.85	46.35	44.05	42.05	42.35	42.55	42.55	42.55	42.55	41.15	39.85	38.75	37.95
Upstate	Small C&I	44.45	42.35	40.35	38.65	38.95	39.15	39.25	39.25	39.55	38.35	37.35	36.55	36.05
Upstate	Large C&I	41.45	39.55	37.75	36.25	36.35	36.45	36.45	36.35	36.55	35.45	34.55	33.95	33.35
Upstate	MW-Scale	34.65	33.45	32.25	31.35	31.85	32.15	32.55	32.75	33.45	32.85	32.35	31.95	31.65
Capital	Residential	47.15	44.75	42.45	40.55	40.85	41.05	41.05	41.05	41.15	39.65	38.45	37.45	36.65
Capital	Small C&I	43.15	41.05	39.15	37.55	37.85	38.05	38.15	38.15	38.35	37.15	36.25	35.45	34.95
Capital	Large C&I	40.35	38.55	36.75	35.25	35.45	35.55	35.55	35.45	35.55	34.55	33.75	33.05	32.55
Capital	MW-Scale	33.45	32.25	31.15	30.25	30.75	31.05	31.35	31.65	32.35	31.75	31.25	30.85	30.65
Downstate	Residential	44.85	42.55	40.45	38.65	38.95	39.05	39.15	39.05	39.15	37.75	36.65	35.65	34.85
Downstate	Small C&I	41.15	39.15	37.35	35.75	36.05	36.25	36.35	36.35	36.55	35.45	34.55	33.85	33.35
Downstate	Large C&I	38.55	36.75	35.05	33.65	33.75	33.85	33.85	33.75	33.95	32.95	32.15	31.55	31.05
Downstate	MW-Scale	31.95	30.85	29.75	28.95	29.35	29.65	29.95	30.25	30.85	30.25	29.85	29.45	29.25
NYC	Residential	53.95	51.15	48.55	46.35	46.65	46.75	46.85	46.75	46.85	45.15	43.75	42.55	41.55
NYC	Small C&I	44.45	42.25	40.25	38.55	38.85	39.05	39.15	39.15	39.35	38.25	37.25	36.45	35.85
NYC	Large C&I	41.55	39.55	37.75	36.25	36.35	36.45	36.45	36.35	36.45	35.45	34.55	33.85	33.25
NYC	MW-Scale	34.45	33.25	32.05	31.15	31.55	31.95	32.25	32.55	33.25	32.55	32.05	31.65	31.35
Long Island	Residential	44.85	42.55	40.45	38.65	38.95	39.05	39.15	39.05	39.15	37.75	36.65	35.65	34.85
Long Island	Small C&I	41.15	39.15	37.35	35.75	36.05	36.25	36.35	36.35	36.55	35.45	34.55	33.85	33.35
Long Island	Large C&I	38.55	36.75	35.05	33.65	33.75	33.85	33.85	33.75	33.95	32.95	32.15	31.55	31.05
Long Island	MW-Scale	33.15	31.95	30.85	29.95	30.45	30.75	31.05	31.35	32.05	31.45	30.95	30.55	30.25

Table 184. Base LCOE ($/MWh nominal) for Installations for EDC Long-term Contract Auction

		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Upstate	Residential	43.85	41.65	39.65	37.85	38.15	38.25	38.35	38.35	38.35	37.05	35.95	35.05	34.25
Upstate	Small C&I	41.35	39.35	37.55	36.05	36.25	36.35	36.35	36.35	36.55	35.45	34.55	33.85	33.35
Upstate	Large C&I	38.45	36.75	35.05	33.65	33.75	33.85	33.75	33.65	33.75	32.85	32.05	31.45	30.95
Upstate	MW-Scale	32.25	31.15	30.15	29.25	29.65	29.95	30.25	30.45	31.05	30.55	30.05	29.75	29.45
Capital	Residential	42.35	40.25	38.25	36.55	36.85	36.95	37.05	36.95	37.05	35.75	34.75	33.85	33.05
Capital	Small C&I	40.05	38.15	36.45	34.95	35.15	35.25	35.35	35.25	35.45	34.45	33.55	32.85	32.35
Capital	Large C&I	37.45	35.75	34.15	32.75	32.85	32.95	32.85	32.85	32.95	31.95	31.25	30.65	30.15
Capital	MW-Scale	31.15	30.05	29.05	28.25	28.65	28.95	29.25	29.45	30.05	29.45	29.05	28.75	28.45
Downstate	Residential	40.35	38.35	36.45	34.85	35.05	35.15	35.25	35.25	35.25	34.05	33.05	32.15	31.55
Downstate	Small C&I	38.25	36.45	34.75	33.35	33.55	33.65	33.65	33.65	33.85	32.85	31.95	31.35	30.85
Downstate	Large C&I	35.75	34.15	32.55	31.25	31.35	31.45	31.35	31.25	31.35	30.55	29.75	29.25	28.75
Downstate	MW-Scale	29.75	28.75	27.75	26.95	27.35	27.65	27.85	28.05	28.65	28.15	27.75	27.45	27.15
NYC	Residential	48.45	45.95	43.65	41.65	41.95	42.05	42.15	42.05	42.15	40.65	39.35	38.25	37.45
NYC	Small C&I	41.25	39.25	37.45	35.85	36.15	36.25	36.25	36.25	36.45	35.35	34.45	33.65	33.15
NYC	Large C&I	38.55	36.75	35.05	33.65	33.75	33.75	33.75	33.65	33.75	32.75	31.95	31.35	30.85
NYC	MW-Scale	32.05	30.95	29.85	29.05	29.35	29.75	29.95	30.15	30.85	30.25	29.75	29.45	29.15
Long Island	Residential	40.35	38.35	36.45	34.85	35.05	35.15	35.25	35.25	35.25	34.05	33.05	32.15	31.55
Long Island	Small C&I	38.25	36.45	34.75	33.35	33.55	33.65	33.65	33.65	33.85	32.85	31.95	31.35	30.85
Long Island	Large C&I	35.75	34.15	32.55	31.25	31.35	31.45	31.35	31.25	31.35	30.55	29.75	29.25	28.75
Long Island	MW-Scale	30.85	29.85	28.75	27.95	28.35	28.65	28.95	29.15	29.75	29.15	28.75	28.35	28.15

HYBRID A: Upfront Incentives for Residential and Small C&I installations and Extension of the New York Main Tier Central Procurement Approach to Large C&I and MW-Scale installations

Table 185. Residential and Small C&I Upfront Incentive Levels ($/W$_{DC}$ Nominal) for Systems Installed in Year Indicated

Region	Size	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Upstate	Residential	$2.32	$2.09	$1.89	$1.70	$1.67	$1.64	$1.60	$1.56	$1.52	$1.37	$1.24	$1.13	$1.02
Upstate	Small C&I	$2.26	$2.05	$1.86	$1.69	$1.66	$1.62	$1.58	$1.53	$1.51	$1.38	$1.27	$1.17	$1.09
Capital	Residential	$2.22	$1.99	$1.77	$1.58	$1.55	$1.50	$1.46	$1.41	$1.37	$1.22	$1.09	$0.97	$0.87
Capital	Small C&I	$2.17	$1.96	$1.77	$1.59	$1.56	$1.52	$1.48	$1.42	$1.40	$1.27	$1.15	$1.05	$0.97
Downstate	Residential	$1.84	$1.61	$1.39	$1.19	$1.16	$1.11	$1.07	$1.03	$0.98	$0.83	$0.70	$0.59	$0.50
Downstate	Small C&I	$1.90	$1.69	$1.49	$1.31	$1.28	$1.23	$1.19	$1.14	$1.12	$0.99	$0.87	$0.78	$0.70
NYC	Residential	$1.79	$1.49	$1.21	$0.96	$0.90	$0.82	$0.75	$0.67	$0.61	$0.43	$0.28	$0.17	$0.09
NYC	Small C&I	$1.30	$1.04	$0.81	$0.62	$0.56	$0.49	$0.42	$0.36	$0.31	$0.20	$0.11	$0.05	$0.01
Long Island	Residential	$1.48	$1.24	$1.01	$0.80	$0.75	$0.70	$0.65	$0.60	$0.56	$0.42	$0.30	$0.21	$0.14
Long Island	Small C&I	$1.48	$1.26	$1.05	$0.86	$0.82	$0.76	$0.70	$0.66	$0.63	$0.51	$0.39	$0.31	$0.25

Table 186. Base LCOE ($/MWh nominal) for Large C&I and MW-Scale Installations for Central Procurement Policy

		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Upstate	Large C&I	38.45	36.75	35.05	33.65	33.75	33.85	33.75	33.65	33.75	32.85	32.05	31.45	30.95
Upstate	MW-Scale	32.25	31.15	30.15	29.25	29.65	29.95	30.25	30.45	31.05	30.55	30.05	29.75	29.45
Capital	Large C&I	37.45	35.75	34.15	32.75	32.85	32.95	32.85	32.85	32.95	31.95	31.25	30.65	30.15
Capital	MW-Scale	31.15	30.05	29.05	28.25	28.65	28.95	29.25	29.45	30.05	29.45	29.05	28.75	28.45
Downstate	Large C&I	35.75	34.15	32.55	31.25	31.35	31.45	31.35	31.25	31.35	30.55	29.75	29.25	28.75
Downstate	MW-Scale	29.75	28.75	27.75	26.95	27.35	27.65	27.85	28.05	28.65	28.15	27.75	27.45	27.15
NYC	Large C&I	38.55	36.75	35.05	33.65	33.75	33.75	33.75	33.65	33.75	32.75	31.95	31.35	30.85
NYC	MW-Scale	32.05	30.95	29.85	29.05	29.35	29.75	29.95	30.15	30.85	30.25	29.75	29.45	29.15
Long Island	Large C&I	35.75	34.15	32.55	31.25	31.35	31.45	31.35	31.25	31.35	30.55	29.75	29.25	28.75
Long Island	MW-Scale	30.85	29.85	28.75	27.95	28.35	28.65	28.95	29.15	29.75	29.15	28.75	28.35	28.15

HYBRID B: Standard Offer PBIs for Residential and Small C&I Installations and Auctions for Long-Term Contracts for Large C&I and MW-Scale Installations

Table 187. LCOE ($/MWh nominal) for Installations for Standard Offer PBI

		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Upstate	Residential	41.65	39.55	37.65	35.95	36.15	36.15	36.05	35.95	35.95	34.75	33.75	32.85	32.15
Upstate	Small C&I	38.35	36.55	34.85	33.45	33.65	33.65	33.65	33.55	33.75	32.75	31.95	31.35	30.85
Capital	Residential	40.25	38.25	36.35	34.75	34.85	34.85	34.85	34.75	34.75	33.55	32.55	31.75	31.05
Capital	Small C&I	37.25	35.45	33.85	32.45	32.65	32.65	32.65	32.55	32.75	31.75	30.95	30.35	29.95
Downstate	Residential	38.25	36.35	34.55	33.05	33.15	33.25	33.15	33.05	33.05	31.95	31.05	30.25	29.55
Downstate	Small C&I	35.45	33.85	32.25	30.95	31.05	31.15	31.15	31.05	31.15	30.25	29.55	28.95	28.55
NYC	Residential	45.95	43.65	41.45	39.55	39.65	39.65	39.65	39.45	39.45	38.05	36.85	35.85	35.15
NYC	Small C&I	38.35	36.45	34.75	33.35	33.45	33.55	33.55	33.45	33.55	32.55	31.75	31.05	30.65
Long Island	Residential	38.25	36.35	34.55	33.05	33.15	33.25	33.15	33.05	33.05	31.95	31.05	30.25	29.55
Long Island	Small C&I	35.45	33.85	32.25	30.95	31.05	31.15	31.15	31.05	31.15	30.25	29.55	28.95	28.55

Table 188. Base LCOE ($/MWh nominal) for Installations for EDC Long-term Contract Auction

		2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Upstate	Large C&I	38.45	36.75	35.05	33.65	33.75	33.85	33.75	33.65	33.75	32.85	32.05	31.45	30.95
Upstate	MW-Scale	32.25	31.15	30.15	29.25	29.65	29.95	30.25	30.45	31.05	30.55	30.05	29.75	29.45
Capital	Large C&I	37.45	35.75	34.15	32.75	32.85	32.95	32.85	32.85	32.95	31.95	31.25	30.65	30.15
Capital	MW-Scale	31.15	30.05	29.05	28.25	28.65	28.95	29.25	29.45	30.05	29.45	29.05	28.75	28.45
Downstate	Large C&I	35.75	34.15	32.55	31.25	31.35	31.45	31.35	31.25	31.35	30.55	29.75	29.25	28.75
Downstate	MW-Scale	29.75	28.75	27.75	26.95	27.35	27.65	27.85	28.05	28.65	28.15	27.75	27.45	27.15
NYC	Large C&I	38.55	36.75	35.05	33.65	33.75	33.75	33.75	33.65	33.75	32.75	31.95	31.35	30.85
NYC	MW-Scale	32.05	30.95	29.85	29.05	29.35	29.75	29.95	30.15	30.85	30.25	29.75	29.45	29.15
Long Island	Large C&I	35.75	34.15	32.55	31.25	31.35	31.45	31.35	31.25	31.35	30.55	29.75	29.25	28.75
Long Island	MW-Scale	30.85	29.85	28.75	27.95	28.35	28.65	28.95	29.15	29.75	29.15	28.75	28.35	28.15

A12.3. Rate Impact Summaries for Selected Policy Options

Table 189. Rate Impacts, Solar Quantity Obligation Using Tradable SRECs, with a Price Floor, $M (Nominal)

	Retail Premium BTM	Wholesale Premium	Direct Rate Impact	Net Metering Rate Impact	Price Suppression	Net Rate Impact
2013	26.6	16.7	43.3	7.1	(3.0)	47.3
2014	57.4	33.8	91.2	16.4	(1.5)	106.1
2015	89.4	54.0	143.4	28.2	(40.1)	131.4
2016	132.4	82.0	214.4	44.2	(359.5)	(100.9)
2017	172.3	109.0	281.4	63.0	(384.4)	(40.0)
2018	212.9	137.3	350.2	84.6	(410.1)	24.6
2019	252.9	166.3	419.2	109.1	(436.8)	91.5
2020	291.0	195.3	486.2	136.8	(464.3)	158.7
2021	336.5	230.8	567.2	168.0	(503.9)	231.4
2022	377.7	266.0	643.7	202.3	(544.1)	301.9
2023	413.4	300.6	714.0	240.1	(586.3)	367.8
2024	443.5	334.4	777.9	281.4	(629.9)	429.4
2025	467.1	367.1	834.2	326.1	(675.5)	484.8
2026	447.7	360.5	808.2	330.3	(554.9)	583.6
2027	427.4	353.6	781.0	334.9	(428.4)	687.5
2028	408.4	346.8	755.2	339.4	(295.0)	799.6
2029	390.0	339.8	729.8	344.1	(154.6)	919.2
2030	372.9	333.1	706.0	348.5	(7.0)	1047.5
2031	356.9	326.0	682.9	353.3	(39.2)	997.0
2032	342.0	318.8	660.9	358.3	(73.1)	946.1
2033	327.1	311.5	638.6	363.4	(108.7)	893.3
2034	312.0	304.1	616.1	368.7	(146.1)	838.7
2035	296.7	296.6	593.2	374.1	(185.4)	781.9
2036	281.8	293.4	575.3	378.9	(148.9)	805.3
2037	267.1	290.3	557.4	383.8	(112.0)	829.2
2038	241.9	278.2	520.1	378.8	(74.9)	823.9
2039	217.1	264.5	481.6	370.6	(37.6)	814.6
2040	193.4	249.7	443.1	359.2	0.0	802.2
2041	170.0	232.2	402.2	341.8	0.0	744.0
2042	146.4	212.7	359.1	320.9	0.0	680.0
2043	123.2	191.2	314.4	296.2	0.0	610.6
2044	100.6	167.8	268.4	267.5	0.0	535.9
2045	78.8	142.6	221.4	234.8	0.0	456.2
2046	56.9	114.6	171.5	197.0	0.0	368.6
2047	38.2	86.5	124.7	154.9	0.0	279.6
2048	22.3	58.0	80.3	108.0	0.0	188.4
2049	9.6	29.2	38.8	56.3	0.0	95.1

Table 190. Rate Impacts, Auction for Long-Term Contracts by EDCs, $M (Nominal)

	Retail Premium BTM	Wholesale Premium	Direct Rate Impact	Net Metering Rate Impact	Price Suppression	Net Rate Impact
2013	23.2	15.4	38.6	7.1	(3.0)	42.6
2014	49.1	30.9	80.1	16.4	(1.5)	95.0
2015	76.0	49.3	125.3	28.2	(40.1)	113.4
2016	112.4	74.9	187.4	44.2	(359.5)	(127.9)
2017	145.1	99.3	244.3	63.0	(384.4)	(77.1)
2018	177.4	124.5	301.9	84.6	(410.1)	(23.6)
2019	208.3	150.0	358.3	109.1	(436.8)	30.7
2020	236.6	175.1	411.7	136.8	(464.3)	84.1
2021	270.9	206.3	477.3	168.0	(503.9)	141.4
2022	300.8	237.1	537.9	202.3	(544.1)	196.1
2023	324.8	266.9	591.7	240.1	(586.3)	245.6
2024	342.9	295.9	638.8	281.4	(629.9)	290.3
2025	356.1	323.5	679.6	326.1	(675.5)	330.1
2026	340.0	317.2	657.2	330.3	(554.9)	432.6
2027	323.9	310.5	634.4	334.9	(428.4)	540.9
2028	310.2	303.9	614.1	339.4	(295.0)	658.5
2029	297.6	297.1	594.7	344.1	(154.6)	784.1
2030	286.0	290.6	576.5	348.5	(7.0)	918.0
2031	272.8	283.7	556.5	353.3	(39.2)	870.6
2032	259.4	276.7	536.1	358.3	(73.1)	821.3
2033	245.9	269.6	515.6	363.4	(108.7)	770.3
2034	232.5	262.4	495.0	368.7	(146.1)	717.5
2035	219.3	255.1	474.4	374.1	(185.4)	663.1
2036	207.0	252.2	459.2	378.9	(148.9)	689.2
2037	194.9	249.3	444.2	383.8	(112.0)	716.0
2038	175.6	238.5	414.1	378.8	(74.9)	717.9
2039	156.7	226.4	383.2	370.6	(37.6)	716.1
2040	139.4	213.4	352.8	359.2	0.0	711.9
2041	121.8	198.2	320.1	341.8	0.0	661.9
2042	104.0	181.3	285.3	320.9	0.0	606.2
2043	86.0	162.7	248.8	296.2	0.0	544.9
2044	68.5	142.5	211.1	267.5	0.0	478.6
2045	51.7	120.9	172.6	234.8	0.0	407.3
2046	35.2	97.0	132.2	197.0	0.0	329.2
2047	22.2	73.0	95.1	154.9	0.0	250.0
2048	12.2	48.8	61.0	108.0	0.0	169.1
2049	4.9	24.5	29.4	56.3	0.0	85.7

Table 191. Rate Impact, HYBRID A: Upfront Incentives for Residential and Small C&I installations and extension of the New York Main Tier Central Procurement approach to Large C&I and MW-Scale installations, $M (Nominal)

	Retail Premium BTM	Wholesale Premium	Direct Rate Impact	Net Metering Rate Impact	Price Suppression	Net Rate Impact
2013	92.1	13.9	106.0	7.1	-3.0	110.1
2014	114.7	27.9	142.6	16.4	-1.5	157.5
2015	132.6	44.5	177.1	28.2	-40.1	165.2
2016	164.7	67.7	232.3	44.2	-359.5	-82.9
2017	191.1	89.6	280.7	63.0	-384.4	-40.7
2018	215.1	112.4	327.5	84.6	-410.1	2.0
2019	237.0	135.4	372.4	109.1	-436.8	44.8
2020	256.0	158.1	414.1	136.8	-464.3	86.5
2021	281.8	186.3	468.0	168.0	-503.9	132.2
2022	285.1	214.1	499.2	202.3	-544.1	157.4
2023	286.2	241.1	527.3	240.1	-586.3	181.1
2024	286.0	267.3	553.3	281.4	-629.9	204.8
2025	285.7	292.4	578.1	326.1	-675.5	228.6
2026	168.4	286.6	455.0	330.3	-554.9	230.4
2027	161.1	280.6	441.7	334.9	-428.4	348.2
2028	155.2	274.7	429.8	339.4	-295.0	474.2
2029	150.1	268.6	418.6	344.1	-154.6	608.1
2030	145.3	262.7	408.0	348.5	-7.0	749.5
2031	139.2	256.4	395.7	353.3	-39.2	709.8
2032	133.0	250.0	383.1	358.3	-73.1	668.3
2033	126.8	243.6	370.4	363.4	-108.7	625.1
2034	120.5	237.0	357.5	368.7	-146.1	580.1
2035	114.3	230.3	344.6	374.1	-185.4	533.2
2036	108.5	227.6	336.1	378.9	-148.9	566.2
2037	102.8	225.0	327.8	383.8	-112.0	599.6
2038	93.2	215.3	308.5	378.8	-74.9	612.3
2039	83.8	204.3	288.1	370.6	-37.6	621.1
2040	74.8	192.6	267.4	359.2	0.0	626.6
2041	65.7	178.9	244.6	341.8	0.0	586.4
2042	56.4	163.7	220.1	320.9	0.0	541.0
2043	47.0	146.9	193.9	296.2	0.0	490.1
2044	37.8	128.7	166.5	267.5	0.0	434.1
2045	28.9	109.2	138.1	234.8	0.0	372.9
2046	20.0	87.6	107.7	197.0	0.0	304.7
2047	12.9	65.9	78.9	154.9	0.0	233.8
2048	7.3	44.2	51.5	108.0	0.0	159.5
2049	3.1	22.2	25.3	56.3	0.0	81.6

Table 192. Rate Impact, HYBRID B: Standard Offer PBIs for Residential and Small C&I installations and Auctions for Long-Term Contracts for Large C&I and MW-Scale installations, $M (Nominal)

	Retail Premium BTM	Wholesale Premium	Direct Rate Impact	Net Metering Rate Impact	Price Suppression	Net Rate Impact
2013	21.9	15.3	37.2	7.1	(3.0)	41.3
2014	46.3	30.7	77.1	16.4	(1.5)	92.0
2015	71.5	49.0	120.4	28.2	(40.1)	108.5
2016	105.6	74.5	180.1	44.2	(359.5)	(135.2)
2017	135.6	98.6	234.2	63.0	(384.4)	(87.2)
2018	164.9	123.6	288.6	84.6	(410.1)	(37.0)
2019	192.4	148.9	341.3	109.1	(436.8)	13.6
2020	216.7	173.8	390.5	136.8	(464.3)	62.9
2021	246.6	204.7	451.3	168.0	(503.9)	115.5
2022	271.9	235.2	507.1	202.3	(544.1)	165.3
2023	291.5	264.7	556.2	240.1	(586.3)	210.1
2024	306.3	293.4	599.7	281.4	(629.9)	251.1
2025	317.4	320.7	638.1	326.1	(675.5)	288.6
2026	303.2	314.3	617.5	330.3	(554.9)	392.9
2027	288.9	307.7	596.6	334.9	(428.4)	503.0
2028	276.5	301.1	577.6	339.4	(295.0)	622.0
2029	265.0	294.3	559.4	344.1	(154.6)	748.8
2030	254.5	287.8	542.3	348.5	(7.0)	883.8
2031	242.2	281.0	523.1	353.3	(39.2)	837.2
2032	229.7	274.0	503.7	358.3	(73.1)	788.9
2033	217.4	266.9	484.4	363.4	(108.7)	739.1
2034	205.6	259.7	465.4	368.7	(146.1)	687.9
2035	193.9	252.4	446.4	374.1	(185.4)	635.0
2036	183.1	249.5	432.6	378.9	(148.9)	662.7
2037	172.6	246.6	419.2	383.8	(112.0)	691.0
2038	154.9	236.0	390.8	378.8	(74.9)	694.7
2039	137.6	223.9	361.6	370.6	(37.6)	694.6
2040	121.3	211.1	332.4	359.2	0.0	691.5
2041	105.0	196.0	301.0	341.8	0.0	642.8
2042	88.6	179.3	267.8	320.9	0.0	588.7
2043	72.4	160.9	233.3	296.2	0.0	529.5
2044	56.9	140.9	197.8	267.5	0.0	465.3
2045	42.2	119.5	161.8	234.8	0.0	396.5
2046	28.1	95.9	124.0	197.0	0.0	321.0
2047	17.1	72.1	89.2	154.9	0.0	244.1
2048	9.0	48.3	57.2	108.0	0.0	165.3
2049	3.4	24.2	27.6	56.3	0.0	83.9

Table 193. Net Ratepayer Impacts of Modeled Policy Mechanisms

Policy ➔		QO w/ Price Floor				EDC LT Contract Auction			
	Metric (units)	2013-2049	Thru 2017	Thru 2022	Thru 2032	2013-2049	Thru 2017	Thru 2022	Thru 2032
Net Ratepayer Impact	(NPV M 2011$)	4,456	130	546	2,824	3,513	59	273	2,091
	% of total rates	1.23%	0.15%	0.35%	1.09%	0.97%	0.07%	0.17%	0.81%
Policy ➔		**Hybrid A: Upfront Incentive/Central Proc.**				**Hybrid B: Std. Offer PBI/LT Contract Auction**			
	Metric (units)	**2013-2049**	**Thru 2017**	**Thru 2022**	**Thru 2032**	**2013-2049**	**Thru 2017**	**Thru 2022**	**Thru 2032**
Net Ratepayer Impact	(NPV M 2011$)	3,032	265	481	1,821	3,264	39	196	1,891
	% of total rates	0.84%	0.30%	0.31%	0.70%	0.90%	0.05%	0.13%	0.73%

APPENDIX 13 – ACRONYMS AND ABBREVIATIONS

Acronym	**Explanation**
ACP	Alternative Compliance Payments
AEPS	Alternative Energy Portfolio Standard
a-Si	amorphous silicon
BGS	Basic Generation Services
BIPV	building integrated PV
BTM	behind-the-meter
CdTe	Cadmium Telluride
CGE	computable general equilibrium
CIGS	Copper Indium Gallium Selenide
CIS	Copper Indium Selenide
CLEAN	Clean Local Energy Accessible Now
CNSE	College of Nanoscale Science and Engineering
CO_2	carbon dioxide
CP	central procurement
CREST	Cost of Renewable Energy Spreadsheet Tool

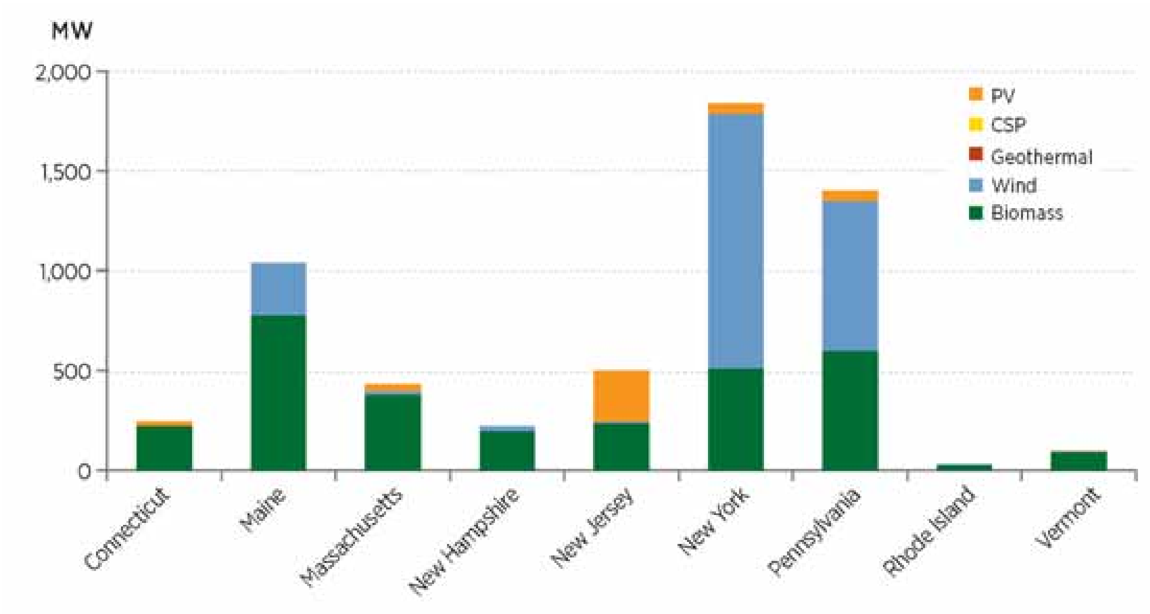
CST	Customer Sited Tier
DPS	Department of Public Service
DSIRE	Database of State Incentives for Renewable Energy
ED	Environmental Disclosure
EDCs	electric distribution companies
EDRG	Economic Development Research Group, Inc.
EPIA	European Photovoltaic Industry Association
ESP	electric service provider
FHFA	Federal Housing Finance Authority
GSP	Gross State Product
GW	gigawatt
ICF	ICF International
INL	Idaho National Laboratory
IPM	Integrated Planning Model
IPP	Independent Power Producer
IREC	Interstate Renewable Energy Council
ITC	Investment Tax Credit
LBNL	Lawrence Berkeley National Laboratory

LCA	La Capra Associates, Inc
LCOE	levelized cost of energy
LIPA	Long Island Power Authority
LMP	locational marginal pricing
LSE	load-serving entities
MACRS	Modified Accelerated Cost-Recovery System
MCG	Meister Consultants Group
mc-Si	multicrystalline silicon
NO_x	nitrogen oxide
NPV	Net Present Value
NREAP	National Renewable Energy Action Plan
NREL	National Renewable Energy Laboratory
NYC	New York City
NYISO	New York Independent Service Operators
NYPA	New York Power Authority
NYSERDA	New York State Energy Research and Development Authority
O&M	operations & maintenance
PACE	Property Assessed Clean Energy

PBF	Public Benefits Fund
PBI	performance based incentive
PILOT	payment in lieu of taxes
PPA	Power Purchase Agreement
PSC	Public Service Commission
PSE&G	Public Service Electric and Gas
PTC	Production Tax Credit
PV	Solar Photovoltaic
PVMC	Photovoltaic Manufacturing Consortium
QO	quantity obligation
RAM	Reverse Auction Mechanism
REAP	Rural Energy for America Program
REC	renewable energy credit
REFTI	Renewable Energy Finance Tracking Initiative
REMI	Regional Economic Models, Inc
REPI	Renewable Energy Production Incentive
RGGI	Regional Greenhouse Gas Initiative
RPC	regional purchase coefficient

RPS	renewable portfolio standard
SACP	solar alternative compliance payment
SBC	System Benefit Charge
SEA	Sustainable Energy Advantage, LLC
SEP	State Energy Plan
SO_2	sulfur dioxide
SREC	Solar Renewable Energy Credits
TBtus	Trillion Btus
TPS	Third Party Suppliers
UMG	upgraded metallurgical-grade
VIMG	Variable Indexed Market Gap
ZREC	Zero-emission Renewable Energy Credit

APPENDIX 14 – NORTHEAST STATE RENEWABLES COMPARISON



Renewables 2010 Installed Nameplate Capacity (MW).

Sources: EIA, LBNL, GEA, SEIA/GTM, Larry Sherwood/IREC, U.S. Census

The above figure was obtained from NREL's 2010 Renewable Energy Data Book. The report was produced by Rachel Gelman, edited by Scott Gossett, and designed by Stacy Buchanan of the National Renewable Energy Laboratory (NREL). The document can be found at www.nrel.gov/analysis/pdfs/51680.pdf.

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